ASIAN PACIFIC ENVIRONMENTAL NETWORK • BIOFUEL WATCH • CENTER FOR BIOLOGICAL DIVERSITY • COMMUNITIES FOR A BETTER ENVIRONMENT • COUNCILMEMBERS CLAUDIA JIMENEZ, EDUARDO MARTINEZ, AND GAYLE MCLAUGHLIN • FRIENDS OF THE EARTH • INTERFAITH CLIMATE ACTION NETWORK OF CONTRA COSTA COUNTY • NATURAL RESOURCES DEFENSE COUNCIL • RODEO CITIZENS ASSOCIATION • SAN FRANCISCO BAYKEEPER • THE CLIMATE CENTER • SUNFLOWER ALLIANCE • 350 CONTRA COSTA COUNTY

March 24, 2022

Re: Appeal of Planning Commission Certification for the Final Environmental Impact Report for the Martinez Refinery Renewable Fuels Project

To the Contra Costa County Board of Supervisors:

Asian Pacific Environmental Network, Biofuel Watch, Center for Biological Diversity, Communities for a Better Environment, Richmond City Councilmembers Claudia Jimenez, Eduardo Martinez and Gayle McLaughlin, Friends of the Earth, Interfaith Climate Action Network of Contra Costa County, Natural Resources Defense Council, Rodeo Citizens Association, San Francisco Baykeeper, The Climate Center, Sunflower Alliance, and 350 Contra Costa County (Appellants) hereby appeal the Contra Costa County Planning Commission's (Commission) certification of a deficient Final Environmental Impact Report (FEIR) for the Martinez Refinery Renewable Fuels Project (Project). The decision to certify the FEIR violated the requirements of the California Environmental Quality Act (CEQA), and was not supported by the evidence presented. This appeal is based on the arguments set forth in this appeal letter; the comments (Comments) submitted concerning the draft Environmental Impact Report (DEIR) (Attachment A); the attached technical supplement (Attachment B); all associated documents in the administrative record; and arguments and information presented before the Planning Commission at its March 23, 2022 hearing.

The decision to certify the FEIR and approve the Project suffers from multiple flaws. First, for the reasons set forth in the Comments, the FEIR fails to meet basic CEQA requirements for disclosure of information on issues critical to assessing these projects; and fails to define and consider appropriate mitigation for significant impacts. The FEIR reflects no significant substantive changes in response to the Comments. Second, the FEIR fails to comply with the CEQA requirement to respond to public comments. As discussed in more detail below, the Response fails to provide any substantive response at all to numerous major issues raised in the Comments; and provides a wholly inadequate response with respect to many others. Third, the FEIR presents critical information describing the Project for the first time, so as to deprive the public of the opportunity to comment on that information. And fourth, the Statement of

Overriding Considerations unlawfully purports to override significant impacts that could have been feasibly mitigated.

For these reasons, Appellants request that the Board of Supervisors grant this appeal, reject certification of the FEIR, and instruct the Department of Conservation and Development (Department) and Commission to develop a revised DEIR that meets the requirements of CEQA be prepared and circulated for public comment.

To be clear, this appeal is not presented as a referendum on the merits of the Project. CEQA is a decision tool to aid government in making decisions about whether a project will have significant impacts; and, if so, whether those impacts have been mitigated as necessary. As of now, that tool is not being used properly under the law. The Project at issue here is unprecedented in scope, and proposes a refining technology – hydrotreating esters and fatty acids (HEFA) – that is newly emerging in California on a large scale. A determination whether large-scale deployment of HEFA technology is an appropriate or feasible path for California, and whether its purported benefits outweigh its impacts, cannot be responsibly made without the thorough vetting of all relevant impacts that CEQA requires. We ask that the Board of Supervisors step in to ensure that review takes place.

I. The Decision to Certify the FEIR is Contrary to Law and Not Supported by Substantial Evidence

The Comments documented numerous and basic ways in which the DEIR failed to meet CEQA's requirements for disclosure and development of mitigation. Nothing provided in the Response or the FEIR adequately explains, excuses, or addresses that failure.

The following is a summary of some key issues left unaddressed in any meaningful way by the FEIR and Response:

- *Failure to provide an adequate project description.* Fundamental to CEQA is the requirement that a project be described in sufficient detail to permit informed decisionmaking. "An accurate, stable and finite project description is the *síne qua non* of an informative and legally sufficient EIR." *San Joaquin Raptor/Wildlífe Rescue Center v. County of Staníslaus*, 27 Cal.App.4th 713, 730 (1994), quoting *County of Inyo v. Cíty of Los Angeles*, 71 Cal.App.3d 185, 193 (1977). The DEIR provided essentially no information about the technology proposed to be deployed in the Project – which technology, as described elsewhere in the Comments, is being proposed at an unprecedented scale in the two Bay Area refinery conversions, and has the potential for numerous harmful direct and indirect environmental impacts. The Comments list in detail the aspects of the proposed technology that must be disclosed in order to adequately evaluate its impacts (Comments at 4-9), but the Response provides only limited partial information. It is only in the Response that the EIR even identifies the proposed HEFA technology by name (Response at 3-37); and it still does not describe essential aspects of its deployment as the basis for the Project.
- *Improper baseline.* The baseline from which the FEIR calculates impacts is continued operation of the Marathon Martinez refinery (Refinery). This baseline is

fictitious, as the Refinery has not operated for nearly two years. The Response fails to address the substantial data specific to the Refinery's operation and reasons for its closure – which, as demonstrated through Commenters' methodical analysis, is quite evidently connected to Marathon's intentional consolidation of operations. Comments at 12-20. The highly general information in the Response concerning overall demand for petroleum products (Response at 3-5 – 9) rebuts none of this – since if such demand actually supported the Refinery's re-opening, that re-opening would have happened already. Marathon's continued maintenance of permits also signifies nothing (see Comment at 12). The inadequacy of the Response concerning the project baseline is further described in the attached technical supplement. The inaccurate baseline skews all other analysis in the FEIR. If the baseline or "no project" scenario is non-operation of the refinery, then the purported decreases in impacts from crude oil refining are actually increases over and above the alternative of non-operation.

- *Failure to account for potentially increased operational upsets.* Commenters presented extensive evidence – supported by both their technical consultant and peer-reviewed analysis – that HEFA biofuel processing can lead to increased process upsets as a result of, among other things, higher processing temperatures and gumming and fouling of refinery equipment that results from repurposing crude oil refining equipment to run lipid feedstocks. These upsets can cause worker and public hazards and increased flaring. Comments at 34-37. While the Response purports to address these problems in the Master Response (O12-70, Response at 3-98), it does not actually do so. The fact that the flares are regulated (Response at 3-42) does not relieve the County of the obligation to disclose and properly mitigate their impacts; and is cold comfort to local citizens subjected to increased risks and pollution. The FEIR also continues to exclude any disclosure or analysis of acute short-term episodic air emissions, key to disclosing flaring impact. Comments at 57-58. We note as well that notwithstanding the FEIR's emphasis on existing regulation, the FEIR does not attach a flare minimization plan (per BAAQMD regulation 12-12-404.2).
- *Failure to account for impact of massive food system oil consumption.* The Project would consume on a colossal scale, unprecedented in California, oils that are either directly used as food products (soybean oil) or indirectly in the food system (corn oil used in animal feed). Commenters extensively documented – based on peer-reviewed science – the environmental impacts risks from this massive disruption in the food system, including and especially the risk that soybean oil demand and associated price spikes (which are already happening as a result of existing biofuel projects) will incentivize production of palm oil and associated deforestation. Comments at 20-34. Commenters cited to the CEQA analysis performed by the California Air Resources Board (CARB) in support of the low carbon fuel standard (LCFS) which specifically directed agencies to review relevant project-specific impacts – making the purported rebuttal in the Response that CARB has "previously evaluated" land use impacts (Response at 3-27) entirely beside the point. Commenters further expressly acknowledged that Marathon may be "unable to specify the exact amount of each

feedstock that will be used" (Comments at 24), making all the statements in the Response that marathon cannot specify "exact" feedstock quantities a red herring. Marathon may not have exact numbers, but Commenters presented available information from which the County could readily have grounded estimates. The suggestion that the needed analysis is too complex or difficult in the context of the DEIR is likewise a red herring, as Commenters pointed out that the calculation formula has already been developed for the LCFS – it just needs to be applied at scale to the Project. Comments at 30.

- *Improper deferment of odor mitigation plan.* The FEIR continues to unlawfully delay addressing potential odors from the project – which may be considerable depending on what feedstocks are used. CEQA plainly prohibits deferring development of mitigation until after the CEQA process is complete – the point of CEQA is to disclose and allow the public to vet essential mitigation measures. "Formulation of mitigation measures shall not be deferred until some future time." CEQA Guidelines § 15126.4(a)(1)(B). Yet despite changes made to proposed Mitigation Measure AQ-2, the County continues to propose that the measure be developed after the completion of the CEQA process, "[d]uring the construction phase of the Project." Response at 3-58. This approach is unlawful and must be corrected.
- *Failure to account for cumulative impacts.* As pointed out in the Comments, the County ignored the elephant in the room when evaluating cumulative impacts. Focused on comparisons to geographically proximate but mostly unrelated projects, it failed to account meaningfully for the fact that the Martinez Project is happening in tandem with the much larger and nearby Phillips 66 Rodeo Renewed project, which purports to be the largest of its kind in the world. These two projects together (added to the dozens of smaller listed projects already in operation or planned) would result in a massive disruption of food crop markets, with resultant land use consequences. Comments at 65-77. The Response fails to address these issues at all, save a conclusory assertion that the FEIR reflects an "appropriate level of generality." Response at 3-33. Furthermore, since filing the Comments, experts have additionally indicated the cumulative impacts of projects like the Martinez Project and Phillips 66 Rodeo Renewed project bear a great risk of causing tens of thousands of hectares of deforestation—thus negating any potential climate benefit asserted.[1]
- *Inconsistency with California climate pathways.* The Comments presented detailed analysis, backed up by data and studies developed for CARB and other state agencies, that the volume of biofuels the Project would produce – particularly in combination with the Rodeo Renewed project - an oversupply of renewable diesel that exceeds the supply anticipated in analysis of California's climate pathways. Comments at 44-58, 72-75. This entire analysis was ignored in the Response.
- *Failure to adequately mitigate transportation risk impacts.* The Comments provided detailed concerns with regard to marine impacts, concerns which were dismissed by

[1] C. Malins and C. Sandford, Animal, vegetable or mineral (oil)? Exploring the potential impacts of new renewable diesel capacity on oil and fat markets in the United States. Cerulogy, ed. International Council on Clean Transportation, Jan. 2022. https://theicct.org/wp-content/uploads/2022/01/impact-renewable-diesel-us-jan22.pdf.

the County under the assumption that non-petroleum feedstocks will react to cleanup methodologies identically to petroleum. O12-127, 138. While support is offered for the assumption that petroleum and non-petroleum finished diesel products react similarly, no support is offered for the assumption that petroleum and non-petroleum **feedstocks** react similarly in marine environments, nor is there any evidence offered that current assets will respond to spills of non-petroleum feedstocks. To put it plainly, there is no guarantee that a large spill of vegetable oil will even be responded to, let alone cleaned up effectively, and there is no analysis of what such a cleanup would entail or the damage such a spill could cause. This impact is recognized as significant and unavoidable, but common-sense mitigation such as committing to response and cleanup of spills of non-petroleum feedstocks at every point along their transportation pathways is not included in the FEIR. While the County's response states that Marathon will update the Northern California Blanket Oil Spill Response Plan to include non-petroleum feedstocks, no such commitment is made in the DEIR at the cites provided, and no legal requirement to respond exists. Requiring such response from non-Project assets is outside of the County's jurisdiction, and so should be required of Project assets as a mitigation measure specific to this project.

This list is not a complete catalogue of all of the deficiencies of the FEIS. It is merely intended to illustrate that enormously important issues raised by Commenters remain unaddressed in the FEIR. The County's overall response to the issues raised by Commenters has been to offer justifications (where it responds to the comments at all) but not remedy. The County made very few changes to the FEIR in response to the Comments; and where it did make changes (for instance, regarding the odor mitigation measure), it did not fix the problem. This appeal should be granted with orders to the Department and Commission to fully address the issues raised by Commenters, including development of mitigation as necessary.

II. The FEIR Fails to Comply with the CEQA Requirement to Respond to Public Comments

A key component of CEQA analysis is a considered and thorough response to public comments raising significant environmental issues, where appropriate making changes to the EIR based on them. CEQA Guidelines § 15008. CEQA sets a high bar for the substance of responses, which must fully address each question raised:

> In particular, the major environmental issues raised when the lead agency's position is at variance with recommendations and objections raised in the comments must be addressed in detail giving reasons why specific comments and suggestions were not accepted. There must be good faith, reasoned analysis in response. Conclusory statements unsupported by factual information will not suffice. The level of detail contained in the response, however, may correspond to the level of detail provided in the comment (i.e., responses to general comments may be general).

Id. at 15008(c).

That bar has not been met here. The Comments were extraordinarily thorough and detailed. Commenters presented hundreds of pages of careful analysis, backed up by technical reports and supported by extensive citation of peer reviewed studies and other materials, all provided to the Department to aid its review. In the Response, the Department simply ignores large swaths of that analysis.

A great many comments simply receive no substantive response at all. Although the Response dutifully catalogues by number each point made by Commenters and purports to address it, this superficially meticulous approach cannot disguise the fact that the Response neglects to actually address a great many such points. The Response contains a "Master Response," which is a narrative discussion concerning some of the major comment topics (baseline, cumulative impacts, land use impacts, alternatives, public safety). When addressing Commenters' specific catalogued points, the Response frequently provides only a single sentence cross-referencing to a section of the Master Response – yet in a great number of cases the Master Response does not actually talk about the point at all.

The discussion in the previous sections provides two particularly important examples of this flawed approach. Commenters provided detailed analysis of (among many other things) the potential problem of biofuel oversupply as it concerns California's climate goals (44-48, 72-75); and the problem of runaway reactions and corrosion of equipment as potential contributors to process upsets (Comments at 35). Both analyses were supported by extensive discussion and explanation in the attached technical reports (which cite in turn to peer-reviewed literature). The Response cross-references in both cases to the Master Response (O12-85 cross-referencing Master Response 4; O12-70 cross-referencing Master Response 5), but in neither case does the cross-referenced section directly address the comment. Additionally, with respect to the oversupply point, large portions of Commenters' meticulous quantitative analysis are simply dismissed with "comment noted" (O12-86-88).

In many other cases, the response falls far short in level of detail to the thoughtful and thorough critique provided by Commenters and/or relies upon conclusory assertions as to why the comment should be summarily dismissed without response. For instance, Commenters' concerns with the EIR's failure to adequately evaluate cumulative impacts (Comments at 65-77) are dismissed with the summary assertion that the FEIR's high level of generality is appropriate (Response 3-33). Although the Comments had pointed out that the list of nearby projects used to assess cumulative impacts included many that are irrelevant to determining the Project's actual cumulative impacts (Comments at 63-64, referencing the inclusion of a self-storage unit development and conversion of a billboard to digital format), the Response persists in referencing these projects as "similar," without further explanation.

These problems are pervasive in the Response. To ensure compliance with CEQA, the Board of Supervisors should grant this appeal and order the Department and Commission to thoroughly respond to each substantive comment presented, as mandated by CEQA Guidelines § 15008(c).

III. The County Has Made No Findings Concerning Choice of Alternatives and Throughput Volumes

The FEIR evaluates two alternatives in addition to the no project alternative: a green hydrogen alternative and the reduced feedstock alternative, with the latter identified as the "environmentally superior" alternative. Yet nowhere in either the FEIR or the staff report does the Department identify which is the preferred alternative, and support that finding with facts and documentation. There is simply no finding at all, much less a finding supported by substantial evidence.

Compounding the problem is that the conditions of approval nowhere specify a limit on throughput. The staff report specifies that the project is "anticipated to process approximately" 48,000 barrels per day (bpd) of feedstock; but nothing in the approval conditions limits throughput to that amount. This is a fatal flaw in the CEQA process. The FEIR analyzed the impact of 48,000 bpd, yet nothing constrains the Project from processing more feedstock than that, with attendant greater impacts.

Given these foundational failures to comply with CEQA, the FEIR and proposed approval conditions as presented should be rejected, with orders that the Department make findings among the alternatives evaluated based upon evidence in the record. Furthermore, findings regarding throughput volume must be reflected in a condition of approval that actually governs throughput.

IV. New Information Describing the Project Provided in the Response Must be Re-Circulated to Allow for Public Comment

While the Response is overall sketchy on detail, in a few places it provides for the first time, information describing the Project. This is most notably true with respect to the proposed technology, HEFA, that the Project will deploy. Commenters, through their technical expert, independently discerned and identified HEFA as the Project technology, and in doing so described its many risks and challenges. Comments at 34-52. However, as noted above, the DEIR did not even name HEFA as the proposed technology, much less describe it. The Comments identified the many aspects of HEFA technology that should have been disclosed and addressed. Comments at 5-9. While the Response does not by any means disclose all of the requested information on HEFA, it does specify for the first time that HEFA will be the technology relied upon by the Project.

This disclosure constitutes essential information that the public as a whole (not just Commenters via their consultant) should have had disclosed to them in the DEIR. It is not sufficient, for purposes of CEQA, to present critical information describing the basic nature of a proposed project only in the FEIR, when opportunity for meaningful public comment has passed. For this reason, the DEIR should be revised to include a thorough description of HEFA technology, containing the components outlined in the Comment, and ordered recirculated in response to this appeal.

V. The Statement of Overriding Considerations is Inadequate

The law is clear that, while a government body may choose to override significant impacts that cannot be feasibly mitigated, it may not use a statement of overriding considerations as a basis for project approval in place of feasible mitigation measures. *City of Marina v. Board of Trustees of California State University* (2006) 39 Cal.4th 341, 368, citing Public Resources Code § 21081 ("A statement of overriding considerations is required, and offers a proper basis for approving a project despite the existence of unmitigated environmental effects, only when the measures necessary to mitigate or avoid those effects have properly been found to be infeasible. . . . CEQA does not authorize an agency to proceed with a project that will have significant, unmitigated effects on the environment, based simply on a weighing of those effects against the project's benefits, unless the measures necessary to mitigate those effects are truly infeasible.").

Here, the FEIR fails to even identify and address significant categories of impacts (including safety impacts and land use impacts), much less mitigate them. And as noted above, the FEIR and staff report did not specifically address the alternative of reduced throughput, and the feasibility of reducing impacts in that manner. Additionally, the mitigation proposed for odors, as described above, is inadequate and unlawful, because it is not being fully defined until after the conclusion of the CEQA process. For this reason alone, the Statement of Overriding Considerations presented by staff is legally inadequate to support approval of the Project.

VI. Conclusion

For the foregoing reasons, Appellants respectfully request that the Board of Supervisors grant this appeal, reject the certification of the FEIR and approval of the Project, and remand to the Department and the Commission with orders that the DEIR be revised so as to comply fully with CEQA; and that they address through thorough disclosure and analysis all issues raised in the Comments.

Respectfully submitted,

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ATTACHMENT A

Comments Concerning DEIR

ASIAN PACIFIC ENVIRONMENTAL NETWORK • BIOFUELWATCH • CALIFORNIA ENVIRONMENTAL JUSTICE ALLIANCE • CENTER FOR BIOLOGICAL DIVERSITY • CITIZEN AIR MONITORING NETWORK • COMMUNITIES FOR A BETTER ENVIRONMENT • COMMUNITY ENERGY RESOURCE • EXTINCTION REBELLION SAN FRANCISCO BAY AREA • FOSSIL FREE CALIDORNIA • FRIENDS OF THE EARTH • INTERFAITH CLIMATE ACTION NETWORK OF CONTRA COSTA COUNTY • NATURAL RESOURCES DEFENSE COUNCIL • RAINFOREST ACTION NETWORK • RICHMOND PROGRESSIVE ALLIANCE • RODEO CITIZENS ASSOCIATION • SAN FRANCISCO BAYKEEPER • STAND.EARTH • SUNFLOWER ALLIANCE • THE CLIMATE CENTER • 350 CONTRA COSTA

December 17, 2021

Via electronic mail (joseph.lawlor@dcd.cccounty.us)[1]

Joseph W. Lawlor Jr., AICP
Project Planner
Contra Costa County
Department of Conservation and Development
30 Muir Rd
Martinez, CA 94553

Re: Martinez refinery renewable fuels project (File No. CDLP20-02046) – comments concerning draft environmental impact report

Dear Mr. Lawler:

Asian Pacific Environmental Network, Biofuelwatch, California Environmental Justice Alliance, Center for Biological Diversity, Communities for a Better Environment, Citizen Air Monitoring Network, Community Energy reSource, Extinction Rebellion San Francisco Bay Area, Fossil Free California, Friends of the Earth, Interfaith Climate Action Network of Contra Costa County, Natural Resources Defense Council, Rainforest Action Network, Richmond Progressive Alliance, Rodeo Citizens Association, San Francisco Baykeeper, Stand.Earth, Sunflower Alliance, The Climate Center, and 350 Contra Costa (collectively, Commenters) appreciate this opportunity to submit comments concerning the Contra Costa County's Draft Environmental Impact Report (DEIR) for the Martinez refinery (Refinery) renewable fuels project (Project) proposed by Marathon Petroleum Corporation (Marathon).

For reasons explained in these comments, the DEIR falls far short of the basic requirements of the California Environmental Quality Act (CEQA), Pub. Resources Code §

[1] The sources cited in this Comment are being sent separately via overnight mail to the County on a thumb drive.

21000 et seq. An EIR is "the heart of CEQA."[2] "The purpose of an environmental impact report is to provide public agencies and the public in general with detailed information about the effect which a proposed project is likely to have on the environment; to list ways in which the significant effects of such a project might be minimized; and to indicate alternatives to such a project." Pub. Res. Code § 21061. The EIR "is an environmental 'alarm bell' whose purpose it is to alert the public and its responsible officials to environmental changes before they have reached ecological points of no return. The EIR is also intended 'to demonstrate to an apprehensive citizenry that the agency has, in fact, analyzed and considered the ecological implications of its action.' …." *Laurel Heights Improvement Assn. v. Regents of University of California* (1988) 47 Cal. 3d 376, 392 ("Laurel Heights I"). A project's effects include all indirect impacts that are "reasonably foreseeable." CEQA Guidelines, § 15064, subd. (d). An indirect environmental impact is "reasonably foreseeable" when "the [proposed] activity is capable, at least in theory, of causing" a physical change in the environment. Union of Medical Marijuana Patients, Inc. v. City of San Diego (2019) 7 Cal.5th 1171, 1197. Courts have analyzed whether it is "reasonably foreseeable" that a project will cause indirect physical changes to the environment in a variety of factual contexts, including changes to off-site land use, lifecycle impacts, and displaced development impacts. *County Sanitation Dist. No. 2 v. County of Kern* (2005) 127 Cal.App.4th 1544. *See Save the Plastic Bag Coalition v. City of Manhattan Beach* (2011) 52 Cal.4th 155, 174; *Muzzy Ranch Co. v. Solano County Airport Land Use Com.* (2007) 41 Cal.4th 372, 382-383. As explained below, the DEIR fails adequately to describe the Project's significant effects, let alone mitigate them.

The DEIR fails to meet these legal standards. The proposed Project is unprecedented in scale and scope. A conversion of an existing refinery of this size is new and untested in California, implicating unknown impacts on operational safety, the agricultural land use systems supplying the feedstock, air emissions, and California's climate goals in the transportation sector, among other things. The law requires more than the limited and uninformative document the County has produced. And the community in and around Martinez who will have to live with the Project, and everyone else potentially affected by it, deserve better.

Its key deficiencies, described in the sections below, include the following:

- *Incorrect baseline.* The assessment of impacts in the DEIR, and its definition of the no-project alternative is grounded in an assumption that in the absence of the proposed conversions, the Refinery would continue processing crude oil at historic levels. This assumption is unsupported and contrary to fact – particularly given that the Refinery had shut down its crude processing operations at the time it proposed the Project.
- *Faulty project description.* The DEIR fails to disclose essential information regarding the proposed biofuel processing operations. This includes key information about feedstocks, as well as about the proposed refining process – such as processing chemistry, hydrogen production and input requirements (a major emissions generator) and refining temperature and pressure (which implicates process upset risks),– that

[2] *Laurel Heights Improvement Assn. v. Regents of University of California* (1988) 47 Cal. 3d 376, 392 ("*Laurel Heights I*").

are essential to an assessment of the proposed new operations on the surrounding community.

- *Failure to consider safety impacts.* The County ignored available information indicating a possible heightened threat of process upsets associated with processing of biofuel feedstocks, creating greater risk for workers and the community.
- *Failure to fully evaluate air quality impacts.* The DEIR, having failed to describe the new proposed process chemistry, fails as well to describe the air emissions impact of that process chemistry on air quality. In particular, the County ignored available information that the new feedstocks risk an increase in flaring and accidental releases; and failed to evaluate the differing air emissions impacts of various proposed feedstocks and product slates. The County also failed to assess the acute short-term hazards from flaring, confining itself to addressing longer-term pollution.
- *Failure to fully evaluate marine impacts.* The DEIR failed to either describe the increase and change in use of marine facilities in connection with the Project, or evaluate the many risks associated with it.
- *Failure to consider the environmental impacts of land use changes.* The Project will require importation of an unprecedented volume of food crop feedstocks such as soy bean oil. Yet the DEIR entirely neglects to consider the environmental impact of this massive diversion of food crop oils on land use – including conversion of forest land to cropland, and incentivizing increases in palm oil production.
- *Inadequate analysis of climate impacts.* The DEIR failed to consider the indirect impacts of the proposed Project on California's climate goals. Full analysis of climate impacts must consider not just emissions from Project operations, but also the impact of a large influx of combustion fuel on climate goals for the transportation sector.
- *Inadequate discussion of hazardous contamination.* The Project will have a limited lifetime given that California's climate commitments lead away from combustion fuel. Accordingly, the DEIR should have considered the environmental impacts associated with decommissioning the Refinery site, which is almost certainly heavily contaminated with toxics. Additionally, the DEIR inadequately evaluated the impact of Project construction and operation on ongoing efforts to remediate and monitor hazardous waste contamination.
- *Deficient cumulative impacts analysis.* Remarkably, even though the DEIR was issued simultaneously with the DEIR for the very similar biofuel conversion project at the Phillips 66 Rodeo refinery, the DEIR makes no effort at all to evaluate the cumulative impact of those two projects together – not to mention other biofuel conversion projects – on key issues such as land use impact and regional air quality.
- *Deficient 'no project' alternative analysis.* Without the proposed Project, the Refinery would have remained closed. Accordingly, the DEIR should have considered the environmental impacts associated with subsequent legal requirements for site decommissioning.
- *Deficient project alternatives analysis.* The DEIR improperly considers the various alternatives for reducing the Project's impact separately rather than together. The option of reducing the scope of the Project can and should have been considered together with the option of using electrolytic hydrogen production. It also defines the Project objectives so narrowly as to distort the consideration of alternatives.

The County had abundant information concerning all of these subjects at its fingertips that would have facilitated the type of robust analysis required for this project, but chose to ignore it in the DEIRs. Commenters requested in their March 22, 2021 CEQA scoping comments on the Notice of Preparation (Scoping Comments) that these topics be considered, and provided voluminous documentation concerning each.[3] The County chose to ignore it all in drafting the DEIR, resulting in a woefully deficient document.

The deficiencies we have identified are too pervasive and deep to be corrected merely by making changes in a final EIR. In order to ensure that the public has full information and opportunity to comment upon, the County must re-circulate a revised DEIR providing fully-documented analysis of all of the issues addressed in this comment (as well as the Scoping Comments). It is unavoidable that addressing the deficiencies identified in these comments in a manner that complies with CEA will necessarily require addition of "significant new information." CEQA Guidelines § 15088.5.[4]

This Comment document includes and incorporates the previously-submitted Scoping Comments as well as the expert report of Greg Karras accompanying this document as an appendix. All sources cited in this document have are being provided electronically to the County under separate cover.

[3] Biofuelwatch, Community Energy reSource, Interfaith Climate Action Network of Contra Costa County, Natural Resources Defense Council, Rodeo Citizens Association, San Francisco Baykeeper, Sierra Club, Stand.Earth, Sunflower Alliance, and 350 Contra Costa, Martinez refinery renewable fuels project (File No. CDLP20-02046) – comments concerning scoping submitted via electronic mail and via overnight mail (Mar. 22, 2021), available at Contra Costa County Department of Conservation & Development Community Development Division. Appendix NOP: Comments on Notice of Preparation (NOP) https://www.contracosta.ca.gov/DocumentCenter/View/72958/Appendix-NOP (accessed Dec. 8, 2021).

[4] The regulations implementing CEQA, 14 CCR 15000 *et seq.*, are cited herein as the CEQA Guidelines.

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I. STATEMENTS OF INTEREST

The interest of each of the Commenters in the DEIR and Project impacts is as follows:

Asian Pacific Environmental Network (APEN) is an environmental justice organization with deep roots in California's Asian immigrant and refugee communities. Since 1993, APEN has built a membership base of Laotian refugees in Richmond and throughout West Contra Costa County. We organize to stop big oil companies from poisoning our air so that our families can thrive.

Biofuelwatch provides information, advocacy and campaigning in relation to the climate, environmental, human rights and public health impacts of large-scale industrial bioenergy. Central to the Biofuelwatch mission is promoting citizen engagement in environmental decision making in relation to bioenergy and other bio-based products – including bioenergy-related decisions on land use and environmental permitting.

California Environmental Justice Alliance (CEJA) is a statewide, community-led alliance that works to achieve environmental justice by advancing policy solutions. We unite the powerful local organizing of our members across the state in the communities most impacted by environmental hazards – low-income and communities of color – to create comprehensive opportunities for change at a statewide level through building community power. We seek to address the climate crisis through holistic solutions that address poverty and pollution, starting in the most over-burdened communities.

Center for Biological Diversity is a national, nonprofit conservation organization with more than 1.3 million members and online activists dedicated to the protection of endangered species and wild places, public health, and fighting climate change. The Center works to secure a sustainable and healthy future for people and for all species, great and small, hovering on the brink of extinction. It does so through science, law, and creative media, with a focus on protecting the lands, waters, and the climate.

Citizen Air Monitoring Network is a community group started in 2016 in Vallejo. Our mission is to make sure the air quality in our community is healthy for all. Vallejo is situated in the middle of five refineries, and we are deeply concerned about the impact of their operation.

Communities for a Better Environment is a California nonprofit environmental justice organization with offices in Northern and Southern California. For more than 40 years, CBE has been a membership organization fighting to protecting and enhancing the environment and public health by reducing air, water, and toxics pollution. Hundreds of CBE members live, work, and breathe in Contra Costa County and the area surrounding the Marathon Refinery. The Northern California office is located in Contra Costa County.

Community Energy reSource offers independent pollution prevention, environmental justice, and energy systems science for communities and workers on the frontlines of today's climate, health, and social justice crises. Its work focuses on assisting communities with a just transition from oil refining and fossil power to clean, safe jobs and better health.

Extinction Rebellion San Francisco Bay Area (XRSFBay) is a local chapter of the global movement to compel business and government to address the climate and ecological crisis. We use nonviolent direct action, theater and art to bring the message that we are running out of time to prevent climate disaster and it is necessary to Tell the Truth, Act Now, Go Beyond Politics and Create a Just Transition for all beings in the Bay Area and beyond.

Fossil Free California is a nonprofit organization of climate justice volunteers. Many are members of the two largest public pension funds in the country, CalPERS and CalSTRS, which continue to invest in fossil fuel companies. Fossil Free California works to end financial support for climate-damaging fossil fuels and promotes the transition to a socially just and environmentally sustainable society. Together with allied environmental and climate justice organizations, we mobilize grassroots pressure on CalPERS and CalSTRS, as well as other public institutions, to divest their fossil fuel holdings.

Friends of the Earth is a national nonprofit environmental organization which strives for a more healthy and just world. Along with our 2 million members and activists we work at the nexus of environmental protection, economic justice and social justice to fundamentally transform the way our country and world value people and the environment. For more than 50 years, we have championed the causes of a clean and sustainable environment, protection of the nation's public lands and waterways, and the exposure of political malfeasance and corporate greed. Our current programs focus on promoting clean energy and solutions to climate change; ensuring a healthy, just and resilient food system where organic is for all; protecting marine ecosystems and the people who depend on them; and transforming our financial, economic and political systems.

Interfaith Climate Action Network of Contra Costa County County (ICAN) is a non-profit environmental justice organization working group of California Interfaith Power and Light, whose offices are in Oakland. CA. The mission of ICAN is to inform and educate faith and non-faith communities and individuals about how to mitigate climate change, advocate with leaders of BILPOC communities before government agencies, industry and other organizations that need to hear our collective voices. They are committed to centering the voices of those most impacted by industry, particularly the communities close to the refineries in Contra Costa County.

Natural Resources Defense Council (NRDC) is a nonprofit environmental membership organization that uses law, science, and the support of more than 440,000 members throughout the United States to ensure a safe and healthy environment for all living things. Over 2,200 of NRDC's members reside in Contra Costa County, some of those in the City of Rodeo. NRDC has a long-established history of working to ensure proper oversight of refining activities and minimize their carbon footprint and other environmental impacts, and ensure that biofuels are produced in a sustainable manner.

Rainforest Action Network (RAN) preserves forests, protects the climate and upholds human rights by challenging corporate power and systemic injustice through frontline partnerships and strategic campaigns. RAN works toward a world where the rights and dignity of all communities are respected and where healthy forests, a stable climate and wild biodiversity are protected and celebrated. RAN is a collaborative organization that challenges corporate power and exposes institutional systems of injustice in order to drive positive systemic change.

Richmond Progressive Alliance is an association of members in Richmond, California, with the explicit goal of taking political decision-making back from corporations and putting power in the hands of the people. The RPA mobilizes people in support of progressive policies and candidates, often in alliance with other local groups.

Rodeo Citizens Association is a non-profit environmental organization with the primary purpose of providing a means for the citizens of Rodeo to address issues of local concern with respect to health, safety, and the environment. Currently, RCA's primary activity is focused on promoting responsible use of land and natural resources around the community and to engage in community outreach activities involving education and awareness of environmental protection issues impacting the region.

San Francisco Baykeeper (Baykeeper) has worked for more than 25 years to stop pollution in San Francisco Bay and has more than five thousand members and supporters who use and enjoy the environmental, recreational, and aesthetic qualities of San Francisco Bay and its surrounding tributaries and ecosystems. San Francisco Bay is a treasure of the Bay Area, and the heart of our landscape, communities, and economy. Oil spills pose one of the primary threats to a healthy Bay, and environmental impacts from increased marine terminal activity directly threaten Baykeeper's core mission of a Bay that is free from pollution, safe for recreation, surrounded by healthy beaches, and ready for a future of sea level rise and scarce resources. San Francisco Baykeeper is one of 200 Waterkeeper organizations working for clean water around the world. Baykeeper is a founding member of the international Waterkeeper Alliance and was the first Waterkeeper on the West Coast. Baykeeper also works with 12 Waterkeepers across California and the California Coastkeeper Alliance.

Stand.earth is a San Francisco-based nonprofit that challenges corporations and governments to treat people and the environment with respect, because our lives depend on it. From biodiversity to air, to water quality and climate change, Stand.earth designs and implements strategies that make protecting our planet everyone's business. Its current campaigns focus on shifting corporate behavior, breaking the human addiction to fossil fuels, and developing the leadership required to catalyze long-term change.

Sunflower Alliance engages in advocacy, education, and organizing to promote the health and safety of San Francisco Bay Area communities threatened by the toxic pollution and climate-disruptive impacts of the fossil fuel industry. They are a grassroots group committed to activating broader public engagement in building an equitable, regenerative, and renewable energy-fueled economy.

The Climate Center works to rapidly reduce climate pollution at scale, starting in California. The Climate Center's strategic goal is that by 2025, California will enact policies to accelerate equitable climate action, achieving net-negative emissions and resilient communities for all by 2030, catalyzing other states, the nation and the world to take effective and equity-centered climate action.

350 Contra Costa is a home base and welcoming front door to mobilize environmental activism. It is comprised of concerned citizens taking action for a better community. They envision a world where all people equitably share clean air, water and soil in a healthy, sustainable, and post-carbon future. It is a local affiliate of 350 Bay Area.

II. THE PROJECT DESCRIPTION IN THE DEIR IS LEGALLY INADEQUATE[1]

An EIR must describe a proposed project with sufficient detail and accuracy to permit informed decision-making, as an inaccurate or incomplete project description renders the analysis of significant environmental impacts inherently unreliable. *See* CEQA Guidelines § 15124. "An accurate, stable and finite project description is the *síne qua non* of an informative and legally sufficient EIR." *San Joaquin Raptor/Wildlífe Rescue Center v. County of Stanislaus*, 27 Cal.App.4th 713, 730 (1994), quoting *County of Inyo v. Cíty of Los Angeles*, 71 Cal.App.3d 185, 193 (1977). "An accurate project description is necessary for an intelligent evaluation of the potential environmental effects of a proposed activity." *San Joaquin Raptor*, 27 Cal.App.4th at730 (citation omitted).

Accordingly, courts have found that even if an EIR is adequate in all other respects, the use of a "truncated project concept" violates CEQA and mandates the conclusion that the lead agency did not proceed in a manner required by law. *Id.* When an EIR fails to disclose the "true scope" of a project because it "concealed, ignored, excluded, or simply failed to provide pertinent information" regarding the reasonably foreseeable consequences of the project, then the EIR is inadequate as a matter of law because it violated the information disclosure provisions of CEQA. *Communities for a Better Environment v. City of Richmond* (2010) 184 Cal.App.4th 70, 82-83 ("*City of Richmond*").

The Project DEIR fails to meet basic CEQA requirements for complete and accurate project description. As described in more detail below, the DEIR's cursory description failed entirely to address the actual processes and process chemistry associated with biofuel refining; and failed to address the operational duration of the Project, which is highly relevant to impacts expected to worsen over time.

A. The DEIR Failed to Describe Aspects of the Proposed Refining Process Essential to Analyzing Project Impacts

As discussed in the sections below, the Project aspects that the DEIR fails to describe, and that are critical to understanding its impacts, are manifold. They include the following:

- Process chemistry for Hydrotreating Esters and Fatty Acids (HEFA), the biofuel refining technology proposed for the Project.
- The class, types, and differing chemistries and processing characteristics of HEFA feedstocks which can have varying upstream land use, air quality, and safety impacts.
- The geographic sources and existing volumetric supplies of each potential feedstock, necessary to fully disclose upstream environmental impacts of land use changes.
- Hydrogen demand associated with HEFA technology, including differential hydrogen demands for production targeting HEFA diesel versus jet fuel, which affect air emission levels.
- The process chemistry of proposed hydrogen production, which could coproduce carbon dioxide, to enable processing of HEFA feedstocks

[1] Supplemental information in support of this analysis is provided in Karras 2021c accompanying this comment, in the section entitled "Project Description and Scope."

- Known differences in hydro-conversion processing between petroleum and HEFA refining, which have potential to lead to increased risk associated with HEFA refining of process upset, process safety hazard, and flaring incidents
- A Project component designed to maximize jet fuel production, which has impacts that differ from diesel production.
- Marine terminal modificatios and changes in use of the terminal, including an increase in ship traffic associated with the Project
- The anticipated and technically achievable operating duration of the project.

1. <u>The DEIR Fails to Disclose Information Regarding the HEFA Biofuel Refining Process Essential to Evaluating its Impacts</u>

The HEFA biofuel refining technology proposed to be used for the Project has important capabilities, limitations, and risks that distinguish it from other biofuel technologies. These differences result in environmental impacts associated with HEFA technology that are unique or uniquely severe as compared with other biofuel technologies.

The DEIR, however, describes none of this. In its entire 400-plus pages, it does not once even mention or reference HEFA, or in any way describe what it is and how it works. This is a major deficiency, and inadequate disclosure that undercuts the integrity of the entire DEIR analysis, for reasons described throughout this Comment with respect to the risks and impacts that attend HEFA production.

The following subsections describe the aspects of the HEFA process that needed to be included in a description of the Project but were not.

a. HEFA as the Proposed Type of Processing

As noted above, the DEIR never once mentions that HEFA is the technology the Project would employ. It can be discerned nonetheless that HEFA is, in fact, the proposed technology, based on the Project's sole reliance upon repurposed refinery hydrotreaters and hydrocrackers for feed conversion to fuels, and upon repurposed refinery hydrogen plants to produce and supply hydrogen for that hydro-conversion processing. This is confirmed by independent expert review of the Project.[2] [3] [4]

But the fact that technical experts (such as Commenters') can read between the lines and discern that HEFA is the proposed technology does not satisfy CEQA's requirement that the County directly disclose this information to the public. Such disclosure was particularly important here given the wide range of existing biofuel technologies and environmentally significant differences between them, and the significant environmental impacts that attend

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[2] Karras, G, *Changing Hydrocarbons Midstream*; technical report and accompanying supporting material appendix for Natural Resources Defense Council, San Francisco, CA, June 2021 (Karras, 2021a).
[3] Karras, G, *Unsustainable Aviation Fuel;* technical report for Natural Resources Defense Council, San Francisco, CA, August 2021 (Karras, 2021b).
[4] Karras, G, *Technical Report in Support of Comments Concerning Marathon Martinez Renewable Fuels Project*; technical report prepared for Natural Resources Defense Council, San Francisco, CA, December 2021 (Karras, 2021c).

HEFA production. In a revised DEIR, the County should disclose, explain, and evaluate the specific impacts of HEFA production.

b. Capabilities and Limitations of HEFA

HEFA processing technology differs from most or all other commercially available biofuel technologies in many ways linked to environmental impacts, in ways that must be known in order to evaluate Project impacts:[5] [6] [7] First, HEFA biofuels can be produced by repurposing otherwise stranded petroleum refining assets, thereby potentially extending the operable duration and resultant local impacts of large combustion fuel refineries concentrated in disparately toxic low income Black and Brown communities. Second, HEFA diesel can be blended with petroleum diesel in pipelines, petroleum storage tanks, and internal combustion vehicles in any amount, thereby raising the potential for competition with or interference with California climate goals for the development of zero-emission vehicles infrastructure for climate stabilization. Third, HEFA technology has inherent limitations that affect its potential as a sustainable substitute for petroleum diesel, jet fuel, or both - including its low yield on feedstock, high hydrogen demand, and limited feedstock supply. The DEIR fails to disclose or describe any these basic differences between HEFA and other biofuels (having failed to even mention HEFA at all), thereby obscuring unique or uniquely pronounced environmental consequences of the type of biofuel project proposed.

c. HEFA process chemistry

HEFA process chemistry reacts lipidic (oily) vegetable oils and animal fats with hydrogen over a catalyst at high temperature and very high pressure to produce and alter the chemical structure of deoxygenated hydrocarbons. Although this is done in repurposed refinery equipment, this process chemistry is radically different from petroleum processing in respects that lead directly to potential environmental impacts of the Project.[8] Moreover, site-specific differences in process design conditions[9]—which have been reported in other CEQA reviews for oil refining projects[10]—can affect the severity of impacts significantly. The DEIR fails to disclose or describe this basic information.

d. Differing hydrogen demand associated with different feedstocks and product slates

Known environmental emissions and hazards of HEFA processing are related in part to the amount of hydrogen demand per barrel of feed converted to biofuel, which varies significantly among HEFA feedstocks and product production targets.[11] The DEIR does not

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[5] Karras, 2021a and 2021b.
[6] Karras, 2021a.
[7] Karras, 2021b.
[8] *Id*.
[9] In addition to process-specific operating temperatures, pressures, and engineered process controls such as quench and depressurization systems, examples include process unit-specific input, internal recycle rates, hydrogen consumption rates, and in some cases, even how those operating conditions interact across refining processes to affect overall hydrogen demand when processing feedstocks of various qualities.
[10] *See* Chevron Refinery Modernization Project, SCH# 2011062042, DEIR Appendix 4.3–URM: Unit Rate Model.
[11] *Id*.

disclose this data. Moreover, to a significant degree, process hydrogen demand and thus resultant impacts may vary depending on plant and project-specific design specifications, data the DEIR likewise fails to disclose or describe.

e. Process chemistry of proposed hydrogen production

This deficiency in the DEIR project description fails to inform that public of known climate impacts the proposed Project would cause and fails to disclose data necessary to adequate review of Project impacts. First, the DEIR fails to specifically disclose that the type of hydrogen production proposed for this "renewable" fuels project would use fossil gas hydrogen production, which, because of its production chemistry, can emit roughly ten tons of carbon dioxide per ton of hydrogen produced.[12] The DEIR further fails to describe the high *and* variable carbon intensity of fossil gas hydrogen technology among specific plants and refineries;[13] and the project-specific hydrogen production design data necessary for impact estimation.

f. Differences between HEFA and petroleum refining that increase risk of process upset, process safety hazard, and flaring incidents

There is a risk of upsets, fires, explosions, and flaring (Section V) linked to specific process hazards that switching from petroleum to HEFA processing has known potential intensify.[14] The DEIR fails to disclose the aspects of the HEFA process creating these hazards, and fails to describe the known differences between HEFA and crude refining that could worsen these impacts.

g. Process upset, process safety hazard, and flaring incident records at the Refinery

The risk of explosion, fire, and flaring impact of the proposed HEFA refining is associated with specific design and operating specifications of the Refinery units proposed for conversion. These specifications, and the attendant risk, can be estimated using available data concerning past incidents involving the same units.[15] [16] The DEIR fails to disclose of address this incident data.

The failure to describe anything at all about the proposed new technology makes a meaningful evaluation of its impacts impossible. Moreover, failing to name and describe HEFA technology eliminated the opportunity for the County to assess whether an alternative biofuel production technology (e.g., Fischer-Tropsch synthesis) might result in different impacts. This analytical limitation was compounded by the DEIR's overly narrow description of the Project's purpose described in Section VIII, which accepted at face value Marathon's commercial desire to repurpose its stranded asset to the greatest extent possible, an assumption that biased the DEIR against consideration of alternative technologies.

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[12] Karras, 2021a.
[13] Sun et al. 2019. Environ. Sci. Technol. 53: 7103–7113. DOI: 10.1021/acs.est.8b06197, https://pubs.acs.org/doi/10.1021/acs.est.8b06197.
[14] Karras, 2021a,
[15] *Id.*
[16] BAAQMD §12-12-406 causal reports; reports relevant to the Project accompany this Comment; recent reports available at https://www.baaqmd.gov/about-air-quality/research-and-data/flare-data/flare-causal-reports

2. The DEIR Fails to Disclose Adequate Information Concerning HEFA Feedstocks

HEFA feedstock is limited to lipids (triacylglycerols and fatty acids freed from them) produced as primary or secondary agricultural products, but there are many different oils and fat in this class of feedstocks, and many environmentally significant differences between them in terms of chemistry and process characteristics.[17] As discussed in Sections IV, VI, and VII, choice of feedstock has a major effect on the magnitude and potential significance of multiple impacts, from upstream land use impacts to process safety to air emissions.

The DEIR, however, provides extremely minimal information concerning Project feedstocks. The DEIR merely lists three types of materials that feedstock for the Project is "expected to include": distillers corn oil (DCO), soybean oil (SBO), and previously-rendered fats (tallow). DEIR at 2-36. It does not reflect a commitment by Marathon to use these feedstocks exclusively. It does additionally state, "As technology evolves, other biological fuel sources such as used cooking oils, and plant and animal processing by-products, may also be used as feedstock using substantially the same equipment and processes as those proposed under the proposed Project." *Id.* This cryptic reference to the possibility that other feedstocks may be used "as technology evolves" is entirely insufficient. What technology is potentially evolving, and what additional feedstocks would such evolved technology allow? What is the availability of such feedstocks?

This description is entirely inadequate to inform the public regarding the nature and impacts of the Project – regardless of whether or not it is possible to specify an exact quantity of each feedstock that will be used into the future. Even the absence of such precise information, the County was obligated to use available information to estimate the likelihood of any given feedstock or combination of feedstocks will be used. Section IV details some of that information on upstream environmental impacts of land use changes, presenting multiple sources of data concerning availability and current use patterns of known feedstocks. That information is sufficient to develop at least a reasonable prediction of the likely mix, or range of potential mixes.

The DEIR should have developed scenarios (including a reasonable worst case scenario – *see* Section IV) for likely feedstock mixes. It should also have specified likely sources for anticipated feedstocks, necessary to facilitate analysis of the upstream environmental impacts of land use changes described in Section IV. Then, as described in that section, the DEIR should have evaluated capping the use of particular feedstocks as a mitigation measure.

3. The DEIR Fails to Disclose a Project Component Designed to Maximize Jet Fuel Production

During and after proposed Project construction, Marathon would configure the repurposed refinery to swing between production targets to maximize HEFA diesel production and those to maximize HEFA jet fuel production. The capability and intent to do so is clear from

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[17] *Id.*

the existence of two hydrocracking reactors, which the Project proposes to operate in series.[18] However, the Project's ability to effectuate this flexibility in production targets depends upon Project aspects not disclosed in the DEIR. Specifically, the DEIR does not disclose the need to boost low jet fuel yield for mid-term Project viability; and neither does it disclose how the Project will achieve that end - including the need to add intentional hydrocracking to HEFA processing for boosting jet fuel yield, and the capability of the 1st Stage Hydrocracker configuration included in the Project to do just that. These steps would increase Project impacts.[19]

B. The DEIR Fails to Sufficiently Describe Changes Affecting the Project's Marine Facilities

The DEIR fails to adequately describe either the marine terminal modifications or changes in use of the terminal.. In the absence of such description, the public is not in a position to evaluate potential Project impacts on such resources.

The DEIR fails to provide an estimate or evaluation of how many ships are projected to use the marine facilities under the new plan. The five-year average for vessel calls was, according to the DEIR, 143. DEIR Table 3-4.

Table 3-4 Comparative Vehicle and Vessel Traffic for Marathon Refinery, 1-year, 3-year Average, and 5-year Average

Vessel or Vehicle	Units	1-year (2019-2020)	1-year (2018-2019)	3-year Average (2017-2020)	5-year Average (2015-2020)
Truck	Miles Traveled	2,837,991	4,559,507	3,972,015	4,146,210
Train	Miles Traveled	2,380	4,820	4,154	4,605
Vessel	Calls	124	161	150	143

Source: Marathon Petroleum Corporation, 2021

No description is provided about whether that number would increase or decrease under the Project.[20] Instead, the public is expected to flip back and forth between different sections and try to estimate for itself whether various levels of feedstocks and finished product traveling across

[18] DEIR pp. 2-20, 2-21: Table 2-1 (separate 1st and 2nd stage hydrocracker components to be deployed for different types of processing).
[19] Karras 2021c.
[20] To the extent this information is buried somewhere in the approximately 450 pages of the DEIR, or in the thousands of pages of appendices, it is not sufficiently clear and/or accessible. For instance, buried in the Air Impacts section of the DEIR is the statement that "Overall, the number of vessel calls at the Amorco MOT is expected to decrease, and the number of vessel calls at the Avon MOT is expected to increase compared to past actual operations." DEIR 3.3-27. No precise information is estimated or given. This type of obfuscation and hiding the ball is not permitted under CEQA. Another random statement, unsupported or referenced, mentions that "[w]ith the Project, it is estimated there will be an increase in deep-draft vessels." DEIR 3.4-37. Impacts must be discussed in a plain, straightforward manner that is easily accessible by the public. That "the Project does not change the unloading/loading capacities of these two MOTs" is irrelevant. *Id*. The DEIR must evaluate proposed conditions against existing conditions, as well as against the various alternatives, including the No Project Alternative. This DEIR fails to do so.

Marathon's wharves constitute an increase in impacts to marine resources. CEQA requires more.

The description of the modifications contemplated under the Project constitute two paragraphs, and the descriptions about how operations would change constitute another two short paragraphs. At the Avon MOT, for instance, we are told that "part of the system of pipes and hoses would be reconfigured to keep the finished petroleum products separate from the renewable feedstocks, and to facilitate transmission of the renewable feedstock through receiving pipelines." DEIR 2-17. That, and the rest of the paragraph describing minor details of the conversation, are the only analysis provided. "[T]he Avon MOT would change from a point of distribution to primarily a facility for receiving of renewable feedstocks." DEIR 2-36. "In total, the Avon MOT would receive an average of 70,000 bpd of renewable feedstocks, gasoline product for distribution, and naptha for transfer." DEIR 2-37. No further specifics are given. Nothing in this description tells the public how much of each feedstock, gasoline product, and naptha will be coming over this wharf, what kinds of vessels will be bringing it, what the chemical composition of the feedstocks and other products will be, what kinds of equipment might be needed should a spill at the Avon MOT occur, how these feedstocks and other products differ from the petroleum products the refinery typically handles and what types of equipment might be more or less effective at addressing these differences, etc. The list of missing details is far longer than the bare 9- and 7-line paragraphs provided in the DEIR. DEIR 2-17, 2-36 – 2-37.

Similarly, the DEIR neglects to give required details of the changes in use expected at the other marine terminal attached to the Marathon Refinery, the Amorco MOT. Here, the public is only told that there will need to be "modifications … to accommodate the smaller marine vessels (25,000- to 50,000-barrel capacities) expected to dock there." The only volume information the public is given is that "use of the Amorco MOT would change from a receiving facility to primarily a distribution facility for loading of renewable diesel product for outbound shipments from the Refinery. Product from the Refinery would be distributed from the Amorco MOT at an average rate of 27,000 bpd of renewable fuel." DEIR 2-37. Again, the public is not told how many smaller (or larger) vessels are expected, what they will be carrying, and all the other questions left unanswered by the description of the Avon MOT, as well. Again, the DEIR only provides two 8-line paragraphs. This is glaringly insufficient.

These deficiencies are of particular import given that the DEIR suggest in places – albeit with extreme lack of clarity – that ship traffic may, in fact, increase in connection with the Project. One among a series of confusing tables buried in Appendix B to Appendix AQ-GH appears to show an increase in pre- to post-Project (though the specific baseline period used is not explained) increase of number of trips to the Avon MOT of 144, from 120 trips pre-Project to 364 trips post-Project. DEIR Appendix AQ-GH, Appendix B, Table B-7. Similarly, onside annual pre-Project emissions are estimated (confusingly) as 210 trips, while total post-Project trips are estimated at 404. *Id.* This at least doubling of the amount of vessel traffic is not adequately evaluated or discussed in the DEIR.

Thus, even if the DEIR's baseline is taken at face value, in spite of the lack of any evidence that purported baselines reflect the actual amount of refining occurring at the Facility ("Marathon recently suspended refining of crude oil in April 2020," DEIR ES-3), the Project may contemplate a significant increase in the amount of feedstock and other potential pollutants crossing through the marine terminal. The public can only speculate, but any such increase represents a significant impact to the marine environment around the refinery, in San Francisco Bay, and all along the routes the shipping transportation will take when delivering and distributing products from the proposed Project. These routes and numbers of ships must be provided in to the public, with adequate opportunity to comment given.

C. The DEIR Failed to Disclose the Operational Duration of the Project, Essential to Describing Impacts that Worsen Over Time

Essential to evaluating environmental impacts of the Project is knowing the period over which the impacts could occur, and could worsen. Thus, the operational duration of the Project is highly relevant to evaluating impacts that may accumulate or otherwise worsen over time.

However, the DEIR fails to disclose the anticipated and technically achievable operational duration of the Project. The necessary data and information could have been obtained from various sources. First, the County should have taken into consideration the declining place of combustion fuel as California moves toward its climate goals, and the County fulfils its own "Diesel Free in '33" pledge (Section VI). Additionally, the County could have requested operational duration data from Marathon as necessary supporting data for its permit application. Such data could also have been accessed from publicly reported sources. For example, process unit-specific operational duration data from Bay Area refineries, including data for some of the same types of process units to be repurposed by the Project, have been compiled, analyzed and reported publicly by Communities for a Better Environment.[21]

III. THE DEIR IDENTIFIES AN IMPROPER BASELINE FOR THE PROJECT [22]

The DEIR commits a major error in using an operating crude oil refinery as a baseline for determining impact significance. Marathon made a clear and widely-reported declaration last year that it no longer intends to refine crude oil at this facility.[23] As discussed below, even though crude oil demand rebounded this year after the initial pandemic-related drop in 2020, Marathon did not re-commence refining operations. It is clear that Marathon has no intention of resuming crude oil refining at the Martinez site for reasons pertaining to operational economics.

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[21] 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.

[22] Supplemental information in support of this analysis is provided in Karras 2021c accompanying this comment, in the section entitled "The DEIR Obscures the Significance of Project Impacts by Asserting an Inflated Alternative Baseline Without Factual Support."

[23] *See, e.g.*, "Marathon Petroleum to Close its Martinez Refinery and Convert it to an Oil-storage Facility," *The Mercury News* August 1, 2020.

A. CEQA Requires Use of an Accurate Baseline

The CEQA baseline, with a limited exception,[24] must "describe physical environmental conditions as they exist at the time the notice of preparation is published." CEQA Guidelines § 15125. "An approach using hypothetical allowable conditions as the baseline results in 'illusory' comparisons that 'can only mislead the public as to the reality of the impacts and subvert full consideration of the actual environmental impacts,' a result at direct odds with CEQA's intent." *Communities for a Better Environment v. South Coast Air Quality Management District* (2010), 48 Cal4th 310, 322 (*Communities for a Better Environment*). Accordingly, the existence of permits allowing a certain level of operation is not appropriately determinative of baseline "physical environmental conditions." *Id.* at 320-21 ("A long line of Court of Appeal decisions holds, in similar terms, that the impacts of a proposed project are ordinarily to be compared to the actual environmental conditions existing at the time of CEQA analysis, rather than to allowable conditions defined by a plan or regulatory framework."). Certainly, using an operating facility as a baseline where the operator has definitively declared a definitive intention to end operations and carried through with it finds no support in the law. *See Association of Irritated Residents v. Kern County Board of Supervisors* (2017), 17 Cal.App.5th 708, 728 (use of operating crude oil facility as baseline was appropriate where the owner "has consistently stated its intention to continue refining at the site," and had continued operations to the extent possible).

Thus, as discussed in the section below, the DEIR analysis concerning baseline identification is legally deficient. The issue is not whether the Refinery's emissions fluctuated over time when it was processing crude oil. DEIR at 3-2, citing CEQA Guidelines § 15125(a)(1). It is that the Refinery *is no longer processing crude oil.* The DEIR cites *Communities for a Better Environment* and the CEQA guidelines for the proposition that agencies have leeway in setting a baseline "where an *existing* operation is present," and may look to past years ... "to characterize that *existing* operation,"; but here *there is no existing operation here to characterize.* DEIR at 1-2, 1-3 (emphasis added). That key fact must determine the establishment of a baseline.

B. Available Evidence Makes Clear that Marathon Made and Carried Out a Decision to Permanently Cease Crude Refining Operations at the Refinery

Determining a proper baseline is critical to all aspects of the DEIR, rendering much of its analysis fatally flawed if the baseline is wrong. If, in fact, the Refinery has been forced by current circumstances to cease crude oil production, then baseline conditions (and the no project alternative) would almost certainly have less environmental impact than any Project alternative.

Available evidence demonstrates that the baseline chosen by the County is simply wrong. It is abundantly clear that Marathon does not, in fact, intend to re-commence crude oil processing at the Refinery if the Project application is not approved. This fact renders key portions of the DEIR analysis quite simply fictional. The Project Description states that an objective of the Project is to "Eliminate the refining of crude oil at the Martinez Refinery while preserving high quality jobs" (DEIR at 1-2); yet crude refining has already been eliminated there. The description

[24] A baseline reflecting projected future conditions is appropriate where "use of existing conditions would be either misleading or without informative value to decision makers and the public." CEQA Guidelines § 15125(a)(1) and (2).

of "Existing Refinery Operations," while acknowledging at the end that the Refinery has been idled, is otherwise written as though it were still functioning, describing transport and other operations in the present tense. DEIR at 1-3 – 4.

The most important piece of information that would support this conclusion is simply the fact that the Refinery has closed – long before the reasonable prospect of a Project approval, and before the Application was developed and submitted. Petroleum refining operations ended there on April 28, 2020.[25] In July 2020, Marathon asserted that closure was permanent with no plans to restart the refinery.[26] This Project launched later. Marathon was "evaluating the possibility" of this Project in August,[27] began "detailed engineering" for the Project during October–December 2020,[28] and "approved these plans" on February 24, 2021.[29] The Project Description does not propose restarting oil refining as an alternative to the Project.

Beyond the fact of the Refinery's current closed state, there is extensive information indicating that the decision to close the Refinery was likely not grounded in plans to pursue the Project, but rather was the result of economic factors and resultant business directions independent of the possibility of re-purposing the refinery to produce biofuels. As discussed in the sections below, available evidence – not disclosed in the DEIR although it was referenced in the Scoping Comments – indicates that the closure of the refinery was based on economic factors unrelated to the Project. Marathon's failure to re-open the Refinery when refined product demand rebounded in 2020 further confirms that the closure decision was permanent. The DEIR should have disclosed that the real question is not whether the Refinery will close – it already has - but whether the Project will enable Marathon to re-purpose its stranded asset, and if so under what conditions and mitigation requirements.

1. <u>Available Evidence, Not Disclosed in the DEIR, Indicates that Marathon Closed the Refinery for Economic Reasons Unrelated to the Project</u>

Available evidence strongly 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.[30] Consolidation, in which fewer refineries build to greater capacity, has been the trend for decades across the U.S.[31] The increase in total capacity concentrated in

[25] 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.
[26] 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.
[27] August 25, 2020 email from A. Petroske, Marathon, to L. Guerrero and N. Torres, Contra Costa County.
[28] 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.
[29] *Id*.
[30] 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
[31] *Id*.

fewer plants[32] 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 almost entirely to the West Coast.[33] In this context, 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[34] and left Marathon with *extra* capacity in California, and across the West Coast, even after its Martinez refinery closed. This is shown by federal refining capacity data.[35] *See* Table 1.

Table 1. 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;* U.S. EIA; www.eia.gov/petroleum/refinerycapacity/archive.

Since refineries wear out in the absence of sufficient reinvestment,[36] and run more efficiently when running closer to full capacity, those decisions to invest and expand elsewhere set the stage for refining asset consolidation. And indeed, Marathon informed its investors that it expected to complete the "consolidation" and expansion of its refining facilities in Los Angeles in the first quarter of 2020,[37] 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.

This consolidation should be understood in the context of a declining market, which further reinforces the evidence that the Refinery closure is independent of plans for the Project.

32 *Id*.
33 PADD 5 Transportation Fuels Markets, September 2015 (PADD 5 2015), U.S. Energy Information Administration (EIA). https://www.eia.gov/analysis/transportationfuels/padd5/
34 Marathon Petroleum Corp., 2019 Annual Report, Part I, p. 9 (2019 Annual Report). https://www.annualreports.com/HostedData/AnnualReportArchive/m/NYSE_MPC_2019.pdf.
35 EIA *Refinery Capacity by Individual Refinery*. Data as of January 1, 2021, and previous years; U.S. Energy Information Administration: Washington, D.C. www.eia.gov/petroleum/refinerycapacity (USEIA 2021).
36 *See* G. Karras, *Decommissioning California Refineries: Climate and Health Paths in an Oil State* at 20, *available at* https://www.energy-re-source.com/decomm (July 2020) and supporting material (Karras 2020).
37 2019 Annual Report. *See* "From the Chairman and CEO" at p. 1.

The Refinery was losing its market. Its domestic market is limited to the West Coast,[38] and West Coast demand for refined products peaked years ago, starting an unprecedented decade-on-decade decline.[39] This decline is accelerating in part because electric vehicles are replacing gasoline demand. Going three times as far per unit energy as gasoline-burning cars, and with fewer moving parts to wear out and fix along the way—e.g., no transmission—battery-electric vehicles will cost less overall.[40] State climate policy is intentionally encouraging the switch to EVs, as part of a policy to phase out most gasoline and diesel vehicles rapidly.[41]

In light of these trends, the COVID-19 pandemic cannot be fingered as the sole cause of the Refinery shutdown, or evidence that it is temporary. Although COVID-19 resulted in an unprecedented temporary curtailment in statewide refining rates,[42] no other California oil refinery closed during the pandemic. COVID further revealed the limits of refineries' increasing reliance on exports to foreign markets, which command lower prices than we pay here, as a way out of this self-inflicted crisis – but again, the impact of that reliance inherently fell harder on the Refinery. Here, the Refinery's setting, landward of a shallow shipping channel that forces tankers to partially unload before calling at Martinez, wait for high tide to sail to and from Martinez, or both,[43] put it in a worse export position than its competitors in Richmond and Los Angeles—and crucially, targeted Martinez rather than Anacordes for closure in the consolidation described above. All available information thus indicates that it was simply more economical – for reasons predating both COVID-19 and the Project – for Marathon to run two refineries closer to full than it was to run three refineries closer to empty. Marathon closed the Refinery in the face of declining fuels demand, when it had more than replaced the capacity of this refinery in Los Angeles, as shown in Table 1. At worst, COVID only accelerated its closure.

Thus, it is highly significant that in the competition between major California refineries over a shrinking, climate-constrained, and electric vehicle-challenged petroleum fuels market, this one closed first; and no other has closed. It lost that competition after Marathon and former owners of this refinery prioritized investments in refining assets elsewhere instead of Martinez. Those investment decisions effectively divested from the competitiveness of this refinery, and were implemented before COVID-19 and before this Project was conceived, engineered, or proposed. These facts must be considered in evaluating the true "no project" baseline that accurate environmental review will depend upon in the DEIR.

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[38] PADD 5 2015.

[39] West Coast (PADD 5) Supply and Disposition, EIA February 26, 2021. http://www.eia.gov/dnav/pet/pet_sum_snd_d_r50_mbbl_m_cur.htm; New Climate Threat: Will Oil Refineries make California the Gas Station of the Pacific Rim? Communities for a Better Environment (CBE). http://www.cbecal.org/resources/our-research

[40] Palmer et al., Total cost of Ownership and Market Share for Hybrid and Electric Vehicles in the UK, US and Japan. *Applied Energy* 209: 108-119 (2018) (Palmer et al. 2018). www.researchgate.net/publication/321642002_Total_cost_of_ownership_and_market_share_for_hybrid_and_electric_vehicles_in_the_UK_US_and_Japan

[41] California Executive Order N-79-20 (September 23, 2020), *available at* https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-text.pdf.

[42] Community Energy reSource. 2021, *COVID and Oil*. https://www.energy-re-source.com/covid-and-oil

[43] Draft Integrated General Reevaluation Report and Environmental Impact Statement, San Francisco Bay to Stockton, California Navigation Study, April 2019. U.S. Army Corps of Engineers: Jacksonville, FL. *See* p. ES-3, maps. https://usace.contentdm.oclc.org/digital/collection/p16021coll7/id/11171

Finally, Marathon's evident intent to close the Refinery, and the history of chronic under-investment in the Refinery by its multiple owners, must be evaluated in the context of the overall increasingly poor profit margins of crude oil refining. These declining profit margins have led to the closure, and in some cases conversion to biofuels production, of numerous refineries in California and throughout the country. Refinery profits across the nation have been declining since before the COVID pandemic.[44] Refineries are closing or converting to biofuel production in the United States and throughout the world, and there is significant doubt whether the economics of refining will improve post-pandemic.[45] The International Energy Agency (IEA) reported in November 2020 that roughly a dozen refinery closures had been announced in the previous few months, with the bulk of the capacity closures – over 1 million b/d – happening in the United States. IEA stated in its monthly report, "There were capacity shutdowns planned for 2020-2021 prior to COVID-19, but the bulk of the new announcements reflect pessimism about refining economics in a world suffering from temporary demand collapse and structural refining overcapacity."[46] Specifically in California, growth reversed years ago in both the crude supply and the market that California refineries were first built to tap.[47] The site-specific structural overcapacity that resulted locked in conditions that effectively ended the viability of crude oil processing at the Refinery, as discussed below.

Thus, the Refinery very likely would have closed—with or without the pandemic—because of chronic under-investment in its competitiveness with other refineries that compete for the same dwindling petroleum fuels market. The DEIR should evaluate all of these facts in establishing the baseline from which Project impacts are measured, and in determining the need for mitigation.

2. <u>The DEIR Improperly Concludes Petroleum Processing Will Recommence Without Basing That Conclusion On Any Relevant Evidence.</u>

A conclusion that Marathon has no intention to re-commence crude refining operations at the Refinery is further supported by the fact that it did not, in fact, do so even when refined fuels demand strongly rebounded in 2021 after early-pandemic declines. That fact should have been disclosed and evaluated as part of the DEIR baseline determination, but was not. The DEIR goes to considerable length scrutinizing production levels *before* the pandemic, and then comparing them to 2019-2020 year, during which demand was much lower. DEIR at 3-3 – 6. However, what it fails to consider is the failure of the Refinery to re-commence crude refining operations *after* 2020, in the demand rebound; and the economic factors that underlie that decision.

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[44] "Bad News for Oil: Refinery Profits are Sliding," *Oilprice.com* January 13, 2020, *available at* https://oilprice.com/Energy/Oil-Prices/Bad-News-For-Oil-Refinery-Profits-Are-Sliding.html.

[45] *See* "Factbox: Oil Refiners Shut Plants as Demand Losses May Never Return," *Reuters* November 10, 2020, *available at* https://www.reuters.com/article/us-global-oil-refinery-shutdowns-factbox/factbox-oil-refiners-shut-plants-as-demand-losses-may-never-return-idUSKBN27R0AI; "Refinery News Roundup: Refinery Closures Loom," *Platts S&P Global* November 12, 2020, *available at* https://www.spglobal.com/platts/en/market-insights/latest-news/oil/111220-refinery-news-roundup-refinery-closures-loom-across-the-globe.

[46] "Permanent Oil Refinery Closures Accelerate as Pandemic Bites – IEA," *Reuters* November 12, 2020, *available at* https://www.reuters.com/article/oil-refining-shutdowns/permanent-oil-refinery-closures-accelerate-as-pandemic-bites-iea-idUSL1N2HY13P.

[47] G. Karras, *Decommissioning California Refineries: Climate and Health Paths in an Oil State* at 20, *available at* https://www.energy-re-source.com/decomm (July 2020) and supporting material (Karras 2020).

2021 post-vaccine refined fuels demand has rebounded from unprecedented pandemic lows—at least temporarily—to reach or exceed pre-COVID levels, accounting for seasonal and interannual variability. At the same time, global oil prices are driving price spikes at the pump. The Phillips 66 Rodeo refinery, which is on roughly the same timeline for its proposed biofuel conversion, is currently refining and selling into this apparent bonanza. As the DEIR points out (DEIR at 5-4), the Marathon Martinez refinery has all the permits and equipment in place to do so as well. If Marathon was ever going to restart crude refining at Martinez, it would have done so.

Fuels demand data for California and U.S. West Coast—AK, AZ, CA, HI, OR, and WA; also known as Petroleum Administration Defense District 5 (PADD 5)—are summarized in tables 2 and 3.

Table 2. 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

Pre-COVID statistics are for the same month in 2012–2019. Multiyear comparison range shown accounts for interannual variability in fuels. Jet fuel totals exclude fueling in California for fuels presumed to be burned outside the state during interstate and international flights. Data from 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. *See* Karras, 2021c Attachment 14.

Table 3. 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) Minimum	Median	Maximum	Comparison of 2021 data with the same month in 2010–2019
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 for "Product Supplied" from *West Coast (PADD 5) Supply and Disposition,* (USEIA, various years). Product Supplied approximately represents demand because it measures the disappearance of these fuels from primary sources, i.e., refineries, natural 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. This multiyear comparison range accounts for interannual variability in fuels demand.

In California, from April through June 2021 taxable fuel sales 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 2. Similarly, 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. 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. *See* Table 3.

California and West Coast refineries supplied the rebound in fuels demand while running well below capacity, as summarized in tables 4 and 5.

Table 4. 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 CEC Fuel Watch, various dates. Statewide refinery capacity as of 1/1/21, after the Marathon Martinez refinery closure, from USEIA, 2021a. 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.

Statewide, four-week average California refinery capacity utilization rates from 20 March through 6 August 2021 ranged from 81.6% to 87.3% (Table 4), similar to those across the West Coast, and well below maximum West Coast capacity utilization rates for the same months in 2010–2019 (Table 5). Moreover, review of Table 4 reveals 222,000 b/d to more than 305,000 b/d of spare California refinery capacity during this period when fuels demand rebounded.

Table 5. 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	NR	80.4 %	87.2 %	96.9 %
October	NR	76.4 %	86.1 %	91.2 %
November	NR	77.6 %	85.3 %	94.3 %
December	NR	79.5 %	87.5 %	94.4 %

NR: Not reported. Utilization of operable capacity, accounting for downstream refinery bottlenecks, types and grades of crude processed, operating permit constraints, and both scheduled and unscheduled downtime for inspection, maintenance, and repairs, from USEIA, 2021b. PADD 5 includes AK, AZ, CA, HI, NV, OR, and WA. Pre-COVID data for the same month in 2010–2019. 2021 data account for Marathon Martinez closure.

Thus, spare California refining capacity during this period when fuels demand increased to reach pre-COVID levels and crude processing at the Marathon Martinez refinery remained shut down (222,000–305,000 b/d) exceeded the total 161,000 barrel per calendar day crude capacity of the Refinery.[48] Had the shuttered Refinery restarted, idled capacity elsewhere would have grown to some 383,000–466,000 b/d, a volumetric market impact exceeding the entire capacity of the largest crude refinery in Western North America—the recently consolidated and expanded Marathon Los Angeles refinery (LAR).[49] *See* Table 1. That is, the idled Martinez capacity would have shifted to other refiners in West Coast, and especially the California refining market, including at the LAR. Marathon did not follow this course of action and re-open the Refinery because it would have made no economic sense to do so. The economics that kept the Refinery closed are akin to commercial airline decisions to limit flights to keep seats full. Running refineries closer to empty costs the refiner nearly as much as running closer to full but refinery revenues shrink disproportionately. It became clear in 2021 that the rational economic choice Marathon made was to keep the Refinery closed in order to limit its idled capacity elsewhere. This was the likely reasoning behind the 2020 closure decision, as documented in the previous subsection, and that reasoning did not change with a rebound in demand. The Refinery would almost surely remain closed indefinitely without Project for the same reasons.

The County's failure to consider any of this market data, and to disclose and evaluation the ongoing refinery consolidation driven by structural overcapacity and the first long sustained statewide and West Coast refined fuels demand decline in the recorded history of the oil industry,[50] was inconsistent with CEQA's requirements, and renders the baseline determination unsupported by substantial evidence.

IV. THE DEIR FAILED TO CONSIDER THE UPSTREAM ENVIRONMENTAL IMPACTS OF FEEDSTOCKS

Commenters' Scoping Comments provided the County with abundant information concerning the potential upstream environmental impact of the Project's proposed feedstocks, including through indirect land use changes.[51] The Scoping Comments offered reliable data that indicates severe shortages in non-food crop sources such as waste oil and animal fats will necessarily require the Project to make use of large amounts of food crop oils, most notably soybean oil.[52] Commenters pointed to studies that have documented the unintended economic, environmental, and climate consequences of using fungible feedstock to produce biofuels. Although the environmental and climate impacts of each may vary in biofuel production, food crop oils share a basic chemical structure that allows them to be used interchangeably or substituted for each other in the market—a characteristic called fungibility. Most notably, Commenters documented the massive spike in demand for biofuel feedstocks that will be induced by the Project.[53]

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[48] USEIA, 2021.
[49] USEIA, 2021.
[50] USEIA, *Supply and Disposition: West Coast (PADD 5);* U.S. Energy Information Admin-istration: Washington, D.C. www.eia.gov/dnav/pet/pet_sum_snd_d_r50_mbbl_m_cur.htm.

[51]Scoping Comments, pp. 10.
[52] Scoping Comments, pp. 12-14.
[53] Scoping Comments, pp. 13.

The DEIR effectively disregards all this information. None of the extensive scientific research and data provided by Commenters concerning the potential upstream indirect impact of food crop feedstocks is even referenced, much less considered - even though both the environmental analysis for the California 2017 Scoping Plan and the Low-Carbon Fuel Standard (LCFS) expected localities to disclose, analyze, and mitigate the potentially destructive consequences of such food crop and food system-related biofuels.

Ultimately, the DEIR concludes, without any analysis resembling an evaluation of either displacement or induced land use changes, that the Project will have no impact on agricultural or forestry resources, and no significant impact on land use. DEIR at 3.1-1, 5-10. The DEIR's very limited discussion and conclusions concerning upstream impacts suffers from the following deficiencies, addressed at greater length in the sections below:

- *Misplaced reliance on the LCFS.* Implicitly, the DEIR appears to justify rejecting the Scoping Comments' concerns about the inducement land use changes based on the existence of the State's Low Carbon Fuel Standard (LCFS), which draws on an analysis of upstream impacts. DEIR at 3.8-12 – 15. That reliance is entirely misplaced.
- *Failure to fully describe feedstocks and their limited availability.* The DEIR fails to fully identify and analyze all potential feedstock the Project will be capable of processing. It merely states what feedstocks the Project's slate is "expected to include" (DEIR at 2-36; *see* Section II), without describing in detail the full suite of feedstocks the Project could potentially refine, and the factors that will determine the feedstock slate. Further, the analysis makes no reference to the data presented in the Scoping Comments concerning the limited availability of biofuel feedstocks, particularly for waste oils and animal fats, and the impact of that limited availability on the likely feedstock mix for the Project.[54]
- *Failure to address impact of feedstock fungibility with an indirect land use change (ILUC) and displacement analysis.* The DEIR nowhere mentions the multiple uses or the fungibility of HEFA feedstocks. There is no mention of the fact that increasing HEFA feedstock demand has induced land conversions or market substitution, ultimately increasing global and domestic agricultural land use changes. Most notably, this includes the increase of overseas palm oil production as domestic soybean oil is diverted from existing uses for biofuel production. [55]
- *Failure to address the magnitude of feedstock demand increase.* The Scoping Comments set forth the large percentage increase in demand for food system-related feedstocks of the type proposed to be used for the Project. These enormous spikes receive no mention in the DEIR.
- *Failure to address environmental impacts from land use changes caused by feedstock demand increases.* There is now broad consensus that increased demand for food crop oil biofuel feedstock has induced land use changes with significant negative environmental and climate consequences. Of particularly great concern are the studies

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[54] *Id.*

[55] Scoping Comments at 14. Ironically, the DEIR for the nearby Phillips 66 biofuel conversion project (Phillips 66 DEIR) – deficient in many other ways – does include a discussion of the fungibility of feedstock commodities, entirely omitted in the Marathon DEIR. Rodeo Renewed Project Draft Environmental Impact Report, 2021, Project Description 3-27. https://www.contracosta.ca.gov/DocumentCenter/View/72880/Rodeo-Renewed-Project-DEIR-October-2021-PDF (accessed Dec 7, 2021) (hereinafter Rodeo Renewed Project 2021 DEIR).

that document a link between increased demand for SBO to a dangerous increase in palm oil production.

- *Failure to meaningfully address mitigation of upstream environmental impacts.* Meaningful mitigation measures, not addressed in the DEIR, would include limiting use of the most harmful types of feedstocks and those likely to induce increased production of such feedstocks. It is likely that the County would need to place caps on the volumes of all feedstocks identified in the DEIR— including SBO and DCO—as a mitigation measure.

A. Existence of Previous LCFS Program-Level CEQA Analysis Does Not Excuse the County from Analyzing Impacts of Project-Induced Land Use Changes and Mitigating Them

The DEIR extensively references the California Low Carbon Fuel Standard (LCFS) crediting system, implicitly (albeit not overtly) suggesting that any land use impacts have already been addressed in the environmental analyses to adopt and amend the LCFS.[56] That approach, if the County means to take it, is entirely unsupportable. While CARB may have evaluated, considered, and hoped to mitigate greenhouse gas emissions from the transportation sector in the design of the LCFS, its land use change modeling was one factor in the quantification of carbon intensity (CI) and associated credits generated for an incremental unit of fuel. It does not purport to assess the impact of an *individual project,* which produces a specific volume of such fuel using a knowable array of feedstocks. That is the County's job in this CEQA review.

The LCFS analysis is not a substitute for CEQA because it does not establish or otherwise imply a significance threshold under CEQA Guidelines § 15064.7. As the DEIR acknowledges,[57] the LCFS is a "scoring system" in that the quantity of LCFS credits available for each barrel of fuel produced is based on the fuel's "score"—its carbon intensity (CI). It calculates the incremental CI per barrel of production of covered fuels by incorporating multiple sources of associated carbon emissions, including those associated with feedstock-based land use changes. The LCFS uses the Global Trade Analysis Project (GTAP), which is mentioned in the DEIR, to incorporate the incremental carbon impact of feedstock-induced indirect land use changes (ILUC) in its incremental CI scoring system. CARB uses GTAP to estimate the amounts and types of land worldwide that are converted to agricultural production to meet fuel demand. [58] DEIR 3.8-13. A closer reading of a key CARB staff report on the LCFS ILUC

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[56] In Section 3.8.12, Greenhouse Gas Emissions Regulatory Setting, the DEIR states, "CARB has previously evaluated, considered and mitigated the environmental impacts associated with increased production and consumption of such fuels at a programmatic level, as part of its adoption, re-adoption and amendment of the LCFS..." DEIR at 3.8-13.

[57] "The LCFS CI [carbon intensity] scoring system therefore reflects CARB's efforts to apply the best available science and economic analyses to mitigate the impacts associated with land use changes occurring both within the U.S. and internationally." DEIR at 3.8-13.

[58] In 2010, the LCFS ILUC analysis updated using GTAP-BIO, which was designed to project the specific effects of one carefully defined policy change—namely the increased production of a biofuel. The methodology behind the change is detailed in Prabhu, A. Staff Report: Calculating Carbon Intensity Values from Indirect Land Use Change of Crop-Based Biofuels, California Environmental Protection Agency & Air Resources Board, 2015; Appendix I-6, I-7, I-19, https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/peerreview/050515staffreport_iluc.pdf (accessed Dec 8, 2021) (hereinafter CARB 2015 LCFS Staff Report ILUC); *see also* Appendix I: Detailed Analysis for Indirect Land Use Change in Low Carbon Fuel Standard Regulation Staff Report: Initial Statement of Reasons for

analysis clarifies, "The GTAP-BIO analysis was designed to isolate the *incremental* contribution… GTAP-BIO is not predicting the overall aggregate market trend—only the *incremental* contribution of a single factor to that trend… GTAP-BIO projections are *incremental* and *relative*" (emphasis added).[59] The ILUC emission factors in the LCFS are calculated by averaging 30 GTAP scenarios with different input parameters per incremental unit increase in fuel demand,[60] disaggregating the land use change estimates by world region and agro-ecological zones (AEZ),[61] and applying annualized emission factors.[62] This incremental adjustment of CI values is useful for augmenting incremental units of biofuel production based on carbon emissions from associated land use changes, but no more.

As a marginal tool, the LCFS ILUC modeling does not set or have a threshold that could distinguish between significant and insignificant impacts under CEQA. The LCFS can determine the incremental CI of one barrel per day of biofuel production, but it says nothing about what happens when an individual project produces a finite amount of fuel. As a result, the LCFS cannot tell you if 48,000 b/d—and its associated environmental and climate impacts—is a little or a lot, insignificant or significant.

Indeed, the 2018 LCFS Final EA indicates that state regulators did not intend for the LCFS to be a replacement for CEQA review of individual projects. The 2018 LCFS Final EA explicitly explains that the environmental review conducted was only for the LCFS program—*not* for individual projects. It repeatedly states, "the programmatic level of analysis associated with this EA does not attempt to address project-specific details of mitigation…"[63] and defers to local agencies like the County who have the "authority to determine project-level impacts and require project-level mitigation…for individual projects."[64] The County not only has the authority, but also the duty to determine project-level land use impacts and require project-level mitigation.

Finally, the LCFS only addresses carbon emissions, as it is designed to assign a CI score to fuels. It thus does *not* address non-carbon impacts associated with land use change. These impacts, as discussed further below, can be ecologically devastating. LCFS CI calculations are not designed to capture the full range of impacts associated with deforestation and other land use changes that may be wrought by increased production of biofuel feedstock crops.[65] Following the guidance of the 2018 LCFS Final EA, it is up to a project-specific DEIR to analyze the

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Proposed Rulemaking, California Air Resources Board, Jan 2015, I-1, https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2015/lcfs2015/lcfs15appi.pdf (accessed Dec 8, 2021) [hereinafter CARB 2015 LCFS Staff Report ILUC Appendix].

59 CARB 2015 LCFS Staff Report ILUC Appendix I-20.

60 CARB 2015 LCFS Staff Report ILUC Appendix I-8, I-16.

61 CARB 2015 LCFS Staff Report ILUC Appendix I-13.

62 CARB 2015 LCFS Staff Report ILUC Appendix Attachment 3-1.

63 CARB analyzed the Conversion of Agricultural and Forest Resources Related to New Facilities, Agricultural and Forest Resource Impacts Related to Feedstock Cultivation and Long-Term Operational Impacts Related to Feedstock Production. *See* Final Environmental Analysis Prepared For The Proposed Amendments To The Low Carbon Fuel Standard And The Alternative Diesel Fuels Regulation, California Air Resources Board: Sacramento, CA, 2018; https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2018/lcfs18/finalea.pdf (accessed Dec 8, 2021) [hereinafter CARB 2018 LCFS Final EA].

64 *Id.*

65 *Id.*

agricultural, forest, soil and water impacts related to land use changes because this analysis is specific to the geographic source of the feedstock crops.

In sum, the County cannot rely on the LCFS as a basis to abdicate its duty to disclose, analyze, and mitigate Project-induced land use changes in the DEIR. That the LCFS passed through program-level environmental review does not exempt any and all individual fuel production projects from CEQA review simply because they might qualify for LCFS subsidies. It is imperative that the DEIR evaluate all effects of use of potential food-grade feedstocks on upstream land use and agricultural systems, and the environmental impacts associated with those effects.

B. The DEIR Should Have Specified That the Project Will Rely Largely on Non-Waste Food System Oils, Primarily Soybean Oil [66]

The Project would convert existing crude oil refining equipment for use in HEFA refining. DEIR at 2-19 *et seq*.[67] The only HEFA feedstocks available in commercially relevant amounts for biofuel refining are from land-based food systems.[68] These include the three feedstocks identified in the DEIR: distillers corn oil (DCO), soybean oil (SBO), and tallow or previously-rendered fats. DEIR at 2-36. However, the proposed refinery technology has the ability to process other oil crops not specifically referenced in the DEIR, such as canola, rapeseed, cottonseed oils, tropical palm oil, and used cooking or other previously used "waste" oils which originate mainly from the oil crops and fats.[69] As noted above in Section II, the DEIR states that the Project is "expected to include" the three identified feedstocks, but reflects no commitment to use these feedstocks exclusively, or in any particular proportion.

The law requires more. Even to the extent Marathon is unable to specify the exact amount of each feedstock that will be used in the Project year to year, the County should have evaluated a "reasonable worst case scenario" for feedstock consumption and its impacts. *See Planning and Conservation League v. Castaic Lake Water Agency* (2009), 180 Cal.App.4th 210, 252; *Sierra Club v. Tahoe Regional Planning Agency*, 916 F.Supp.2d 1098, 1151-52 (E.D.Cal. 2013). While the County was not required to address entirely speculative worst case scenarios, neither may it use the mere existence of uncertainty as justification to avoid addressing any feedstock-varying scenarios at all. *Id.* Neither is analysis *only* of the reasonable worst case scenario necessarily sufficient – the County was required to evaluate a reasonable array of scenarios, including but

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[66] Portner, H.O. et al., Scientific outcome of the IPBES-IPCC co-sponsored workshop on biodiversity and climate change, IPBES Secretariat, June 2021, 18-19, 28-29, 53-58. https://www.ipbes.net/events/launch-ipbes-ipcc-co-sponsored-workshop-report-biodiversity-and-climate-change (accessed Dec 8, 2021).
[67] Although as discussed in Section II the DEIR never specifically mentions HEFA, the description generally references that technology, *i.e.,* briefly noting that the process feeds lipids, and more specifically, lipids from triacylglycerols (TAGs), and fatty acids cleaved from those TAGs, from biomass into the refinery.
[68] While fish oils are commercially available, they are extremely limited in availability. Food and Agriculture Organization of the United Nations (FAO), *The State of World Fisheries and Aquaculture: Sustainability in action*, 2020. http://www.fao.org/documents/card/en/c/ca9229en (accessed Dec 12, 2021); *see also* Yusuff, A., Adeniyi, O., Olutoye M., and Akpan, U. *Waste Frying Oil as a Feedstock for Biodiesel Production*, IntechOpen, 2018. http://dx.doi.org/10.5772/intechopen.79433 (accessed Dec 8, 2021).
[69] *See* Karras, 2021a and 2021b.

not necessarily limited to the worst case scenario, in order to provide full disclosure. *City of Long Beach v. City of Los Angeles* (2018), 19 Cal.App.5th 465, 487-88.

Whether the list is exclusive or not, appropriate DEIR impact analysis should reflect historic, current, and projected feedstock availability that will influence the proportional selection of feedstocks as demand for feedstock increases. While market forces will also influence the selection of feedstocks (as acknowledged in the parallel Rodeo Renewed DEIR[70]), the County cannot ignore this readily available information about feedstock availability. Under CEQA, the County must still identify analyze the significance of the foreseeable feedstock mix scenarios—including a reasonable worst case scenario—accordingly.

Had it done so, the County would have determined that the very large majority of the feedstock the Project will use will almost certainly come from food crop and food system oils—predominantly SBO but also potentially others like DCO —with very little coming from waste oils such as tallow. One indicator for the likely predominant role of SBO and other food crop oils for the Project is the current breakdown of feedstock *demand* for biodiesel (another lipid-based biofuel) production.[71] From 2018 to 2020, 59% of biodiesel in the United States was produced from SBO as feedstock, compared to 11% from yellow grease, 14% from DCO, and only 3% from tallow, or rendered beef fat.[72] Another indicator is the limited domestic *supply* of alternative feedstock sources. Tallow and other waste oil volumes have come nowhere near meeting current biodiesel feedstock demand, with little prospect of expanding soon.[73] The future possible supply for these wastes is substantially constrained by the industries that produce them, and as such are generally nonresponsive to increased levels of demand. As a result, supplies will likely only increase at the natural pace of the industries that produce them.[74] Thus, a large fraction of feedstock likely to be used for the Project will be food crop oils – both purpose-grown food crop oils, such as SBO, canola, rapeseed, and cottonseed oils; and oils currently used in the food system, such as DCO.

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[70] Rodeo Renewed DEIR 3.8.3.5.

[71] *See* Zhou, Y; Baldino, C; Searle, S. *Potential biomass-based diesel production in the United States by 2032*. Working Paper 2020-04. International Council on Clean Transportation, Feb. 2020, https://theicct.org/sites/default/files/publications/Potential_Biomass-Based_Diesel_US_02282020.pdf (accessed Dec 8, 2021).

[72] Uses data from EIA Biodiesel Production Report, Table 3. Feedstock breakdown by fat and oil source based on all data from Jan. 2018–Dec. 2020 from this table. U.S. Energy Information Administration (EIA), Monthly Biodiesel Production Report Table 3, Feb. 26, 2021, https://www.eia.gov/biofuels/biodiesel/production/table3.pdf (accessed Dec. 14, 2021). Data were converted from mass to volume based on a specific gravity relative to water of 0.914 (canola oil), 0.916 (soybean oil), 0.916 (corn oil), 0.90 (tallow), 0.96 (white grease), 0.84 (poultry fat), and 0.91 (used cooking oil). See also Zhou, Baldino, and Searle, 2020-04.

[73] *See* Baldino, C; Searle, S; Zhou, Y, *Alternative uses and substitutes for wastes, residues, and byproducts used in fuel production in the United States*, Working Paper 2020-25, International Council on Clean Transportation, Oct. 2020, https://theicct.org/sites/default/files/publications/Alternative-wastes-biofuels-oct2020.pdf (accessed Dec 8, 2021).

[74] *See* Zhou, Baldino, and Searle, 2020-04.

C. The Project's Use of Feedstocks From Purpose-Grown Crops For Biofuel Production Is Linked to Upstream Land Use Conversion

There is now broad consensus in the scientific literature that increased demand for food crop oil biofuel feedstock has induced or indirect land use changes (ILUC) with significant negative environmental and climate consequences.[75] ILUC is already widely considered in policies to evaluate the environmental benefits of biofuels relative to fossil fuel counterparts, including the California Low-Carbon Fuel Standard, Renewable Fuel Standard (RFS),[76] EU Renewable Energy Directive (RED) and RED II,[77] and ICAO CORSIA[78]. After a decade of studies, soybean oil will likely be designated a high-ILUC risk biofuel that will be phased out of European Union renewable energy targets by 2030. [79] Belgium has already banned soybean oil-based biofuels as of 2022.[80]

HEFA biofuels can result in ILUC in several ways. One way is through the additional lands converted for crop production as feedstock demand for that crop increases. In simple economic terms, increased HEFA biofuel production requires increased feedstock crops, resulting in increased prices for that crop. The price increases then cause farmers of existing cultivated agricultural land to devote more of such land to that crop as it becomes more lucrative,[81] and are incentivized to clear new land to meet increased demand.[82][83]

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[75] *See* Portner et al., 2021.; *see also* Searchinger, T. et al., *Use of U.S. Croplands for Biofuels Increases Greenhouse Gases Through Emissions from Land Use Change*. Science, 2008, 319, 1238, https://science.sciencemag.org/content/319/5867/1238 (accessed Dec 8, 2021) (This landmark article notes one of the earliest indications that certain biofuel feedstock are counterproductive as climate measures.)

[76] O'Malley, J. *U.S. biofuels policy: Let's not be fit for failure*, International Council on Clean Transportation, Oct. 2021, https://theicct.org/blog/staff/us-biofuels-policy-RFS-oct21 (accessed Dec 11, 2021).

[77] Currently, the European Union is phasing out high ILUC fuels to course correct their biofuel policies based on nearly a decade of data. Adopted in 2019, Regulation (EU) 2019/807 phases out high ILUC-risk biofuels from towards their renewable energy source targets by 2030. ILUC – High and low ILUC-risk fuels, Technical Assistance to the European Commission. https://iluc.guidehouse.com/ (accessed Dec 8, 2021).

[78] International Civil Aviation Organization (ICAO), "CORSIA Supporting Documents: CORSIA Eligible Fuels – Life Cycle Assessment Methodology," 2019. https://www.icao.int/environmental-protection/CORSIA/Documents/CORSIA%20Supporting%20Document_CORSIA%20Eligible%20Fuels_LCA%20Methodology.pdf (accessed Dec 11, 2021).

[79] Malins, C. *Risk Management: Identifying high and low ILUC-risk biofuels under the recast Renewable Energy Directive*; Cerulogy, 2019; 4, 14. http://www.cerulogy.com/wp-content/uploads/2019/01/Cerulogy_Risk-Management_Jan2019.pdf (accessed Dec 8, 2021).

[80] Belgium to ban palm- and soy-based biofuels from 2022. Argus Media, Apr. 14, 2021. https://www.argusmedia.com/en/news/2205046-belgium-to-ban-palm-and-soybased-biofuels-from-2022 (accessed Dec 8, 2021).

[81] *See Appendix I: Detailed Analysis for Indirect Land Use Change in Low Carbon Fuel Standard Regulation Staff Report: Initial Statement of Reasons for Proposed Rulemaking,* California Air Resources Board, Jan 2015, I-1, https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2015/lcfs2015/lcfs15appi.pdf (accessed Dec 8, 2021) [hereinafter CARB 2015 LCFS Staff Report ILUC Appendix].

[82] *Id.*

[83] Lenfert et al., *ZEF Policy Brief No. 28;* Center for Development Research, University of Bonn, 2017. www.zef.de/fileadmin/user_upload/Policy_brief_28_en.pdf; Gatti, L.V., Basso, L.S., Miller, J.B. et al. Amazonia as a carbon source linked to deforestation and climate change. *Nature* 595, 388–393 (2021). https://doi.org/10.1038/s41586-021-03629-6 (accessed Dec 8, 2021); Nepstad, D., and Shimada, J., *Soybeans in the Brazilian Amazon and the Case Study of the Brazilian Soy Moratorium,* International Bank for Reconstruction and Development / The World Bank, Washington, D.C., 2018 (accessed Dec 8, 2021); Rangaraju, S, 10 years of EU fuels policy increased EU's reliance on unsustainable biofuels, Transport & Environment, Jul 2021.

A second way that HEFA biofuels can cause ILUC, most relevant for the feedstocks proposed for the Project, is through displacement and substitution of commodities, leading to the conversion of land use for crops other than that of the feedstock demanded. As mentioned above, oil crops are to a great degree fungible—they are, essentially, interchangeable lipid, triacylglycerol (TAG) or fatty acid inputs to products.[84] Due to their fungibility, their prices are significantly if not wholly linked: when the price of one crop increases, another cheaper crop will be produced in greater volumes to fill the gap as consumers substitute their use of the more expensive crop. This substitution effect is known as displacement.[85] Studies have extensively documented the linkage between rising prices for one biofuel feedstock oil crop and the expanding production of another substitute oil crop.[86] These effects have been demonstrated for each of the three feedstocks identified in the DEIR—SBO, DCO, and tallow.

Soybean Oil (SBO): SBO accounts for only about a third of the total market value of whole soybeans, with the majority of the value in the soybean meal. As a result, the livestock feed market is the primary driver of SBO production, with biofuel demand as an important secondary driver. This means that SBO demand will lead to both *direct* and *indirect* economic pressures to convert domestic and overseas lands for soybean crops.[87] For example, increased biofuel demand is a partial contributor to deforestation in South America for production of soybean crops.[88] Meanwhile, the supply of *palm oil* also responds to SBO prices. Historical data show that SBO price increases lead to increased imports of palm oil, as domestic consumers substitute SBO with palm oil. .[89] [90] The price of SBO, which would be the predominant source

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https://www.transportenvironment.org/wp-content/uploads/2021/08/Biofuels-briefing-072021.pdf (accessed Dec 8, 2021).

[84] The DEIR for the similar Rodeo Renewed biofuel conversion project expressly recognized this fungibility: "The different uses of the commodity and whether or not there are substitutes for those commodities also affect the renewable feedstocks market. For example, soy and corn can both be used for livestock feed or human food production. If one commodity increases in price, farmers may be able to switch to the other commodity to feed their livestock for a cheaper cost (CME Group). This is particularly important for renewable feedstocks given the different uses for oilseeds, including food production and animal feedstocks, and the different vegetable oils that may be used as substitutes (e.g., canola oil may be a substitute for soybean oil)." Rodeo Renewed DEIR 3.8.3.2.

[85] *See generally* Pavlenko, N. and Searle, S. *Assessing the sustainability implications of alternative aviation fuels*. Working Paper 2021-11. International Council on Clean Transportation, Mar 2021. https://theicct.org/sites/default/files/publications/Alt-aviation-fuel-sustainability-mar2021.pdf (accessed Dec 8, 2021).

[86] *See* Malins, C. *Thought for food: A review of the interaction between biofuel consumption and food markets*, Transport & Environment, Sept 2017. https://www.transportenvironment.org/wp-content/uploads/2021/07/Cerulogy_Thought-for-food_September2017.pdf (accessed Dec 8, 2021).

[87] See Martin, J. '*Soybean freakonomics'* in *Everything You Ever Wanted to Know About Biodiesel (Charts and Graphs Included!)* Union of Concerned Scientists, The Equation, Jun 22, 2016. https://blog.ucsusa.org/jeremy-martin/all-about-biodiesel/ (accessed Dec 8, 2021).

[88] Malins, C., *Soy, land use change, and ILUC-risk: a review*, Cerulogy, 2020a, https://www.transportenvironment.org/wp-content/uploads/2021/07/2020_11_Study_Cerulogy_soy_and_deforestation.pdf

[89] *See* Santeramo, F. and Searle, S. *Linking soy oil demand from the US Renewable Fuel Standard to palm oil expansion through an analysis on vegetable oil price elasticities*. Energy Policy 2018, 127, 19 https://www.sciencedirect.com/science/article/abs/pii/S0301421518307924 (accessed Dec 8, 2021).

[90] Searle, S. *How rapeseed and soy biodiesel drive oil palm expansion*, The International Council on Clean Transportation, Jul 2017. https://theicct.org/publications/how-rapeseed-and-soy-biodiesel-drive-oil-palm-expansion (accessed Dec 8, 2021).

of feedstock in this Project, is already skyrocketing, in part in connection with increased biofuel production.[91] Marathon has ostensibly recognized the unacceptable environmental destruction associated with palm oil production, also described in subsection E, in its commitment not to use palm oil. However, by proposing a Project that will heavily rely on SBO, palm oil production and use will nonetheless increase because of SBO feedstock fungibility.

DCO: Distiller's corn oil (DCO) is a co-product produced during ethanol production, alongside another co-product, distiller's grains with solubles (DGS).[92] DCO can be extracted from distiller's grains with solubles (DGS), leading to substitution effects between the two commodities.[93] DGS is a valuable agricultural residue commonly used in animal feed. In response to recently increasing biofuel feedstock demand, ethanol producers have been increasingly extracting DCO from DGS.[94] Yet extracting DCO from DGS feed also removes valuable nutrients, requiring farmers to add even more vegetable oils or grains to replace the lost calories in their livestock feed.[95] In practice, the most economical, and common source for these replacement nutrients has been more DCO, or DGS containing DCO, both of which then require additional corn crops.[96] Thus, while DCO is not an oil from purpose-grown crops, any increase in DCO demand for Project biofuel production will ultimately increase food corn crop demand.[97]

Tallow: Tallow represents a small portion of the total value of cattle, less than 3%, and as a result, increased demand for tallow will only result in marginal increases in tallow supply, even with substantial price increases.[98] Like several other animal fats and DCO, tallow is not truly a waste fat, because it has existing uses. Tallow is currently used for livestock feed; pet food, for which it has no substitute; and predominantly, the production of oleochemicals like wax candles,

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[91] *See* Walljasper, C. GRAINS–Soybeans extend gains for fourth session on veg oil rally; corn mixed. *Reuters*, Mar 24 2021. https://www.reuters.com/article/global-grains-idUSL1N2LM2O8 (accessed Dec 8, 2021).

[92] Malins, C., Searle, S., and Baral, A., *A Guide for the Perplexed to the Indirect Effects of Biofuels Production*, International Council on Clean Transportation 2014, 80 ("Co-products can be broadly placed into two categories: those that directly displace land-based products and have land use implications, such as distillers grains with solubles (DGS) displacing soybean meal, and those that displace non-land-based products such as urea, glycerol, and electricity. Co-products in the second category do not have land use implications but have greenhouse gas (GHG) reduction implications."). https://theicct.org/sites/default/files/publications/ICCT_A-Guide-for-the-Perplexed_Sept2014.pdf (accessed Dec 8, 2021).

[93] *Id*. at 79.

[94] Searle, S. *If we use livestock feed for biofuels, what will the cows eat?* The International Council on Clean Transportation, Jan. 2019. https://theicct.org/blog/staff/if-we-use-livestock-feed-biofuels-what-will-cows-eat (accessed Dec 8, 2021).

[95] *See* Final Rulemaking for Grain Sorghum Oil Pathways. 81 Fed. Reg. 37740-37742 (August 2, 2018), https://www.govinfo.gov/content/pkg/FR-2018-08-02/pdf/2018-16246.pdf (accessed Dec 8, 2021); *see also* EPA sets a first in accurately accounting for GHG emissions from waste biofuel feedstocks, International Council on Clean Transportation Blog (Sept. 2018), https://theicct.org/blog/staff/epa-account-ghg-emissions-from-waste (accessed Dec 8, 2021).

[96] Searle 2019.

[97] Gerber, P.J. et al., *Tackling climate change through livestock—A global assessment of emissions and mitigation opportunities*, Food and Agriculture Organization of the United Nations 2013, 8. https://www.fao.org/3/i3437e/i3437e.pdf (accessed Dec 8, 2021).

[98] Pavlenko, N. and Searle, S. *A comparison of methodologies for estimating displacement emissions from waste, residue, and by-product biofuel feedstocks*, Working Paper 2020-22, International Council on Clean Transportation, Oct 2020, 6. https://theicct.org/sites/default/files/publications/Biofuels-displacement-emissions-oct2020.pdf (accessed Dec 8, 2021).

soaps, and cosmetics.[99] As a result, the dominant impact of increased tallow demand is through diversion of existing uses. Therefore, increased tallow production will likely yield increased palm oil and corn oil production.[100]

D. The Scale of This Project Would Lead to Significant Domestic and Global Land Use Conversions

As shown above, all of the feedstocks demanded by the Project would lead to either direct or indirect increases in crops, such as soy, oil palm, and corn, which will require land use conversion. These potential land use impacts are of particular concern with respect to a project of the magnitude proposed by Marathon, given its potential to significantly disrupt food crop agricultural patterns.

The DEIR failed to address the significant impact of the Project's demand for food crop feedstocks on agricultural markets, and hence on land use. The volume of food crop oil feedstock, namely SBO, likely to be required for the Project represents a disproportionately large share of current markets for such feedstock.[101] The anticipated heavy spike in demand for food crop oils associated with the Project (not to mention the cumulative spike when considered together with other HEFA projects such as Rodeo Renewed, *see* Section VIII) will have significant environmental impacts, as discussed in the next subsection.

To assess the significance the Project's anticipated feedstock use, the County could and should have analyzed the Project's proposal to consume up to 48,000 b/d[102] of lipid feedstocks in the context of both total biofuel demand and total agricultural production data. With respect to biofuel demand, data from the U.S. Energy Information Administration on total biodiesel production in the United States indicates that oil crop and animal fat demand associated with U.S. biodiesel production on average totaled approximately 113,000 barrels per day (b/d) for the time period 2018-2020.[103] The Project would increase this nationwide total by a full 42 percent.[104]

With respect to total production, US agricultural yield of the types of oil crops and animal fats that are potentially usable as Project feedstocks was roughly 372,000 b/d on average.[105]

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[99] Baldino, Searle, and Zhou, 2020-25, pp. 6.
[100] Pavlenko and Searle 2020-22, pp. 26.
[101] *See* Karras, G. Biofuels: Burning Food?, Community Energy resource, 2021. https://f61992b4-44f8-48d5-9b9d-aed50019f19b.filesusr.com/ugd/bd8505_a077b74c902c4c4888c81dbd9e8fa933.pdf (accessed Dec 8, 2021).
[102] DEIR 2-2.
[103] Uses EIA data from the Monthly Biodiesel Production Report, Table 3. This 113,000 b/d estimate is based on all data from Jan. 2018–Dec. 2020 from this table. U.S. Energy Information Administration (EIA), Monthly Biodiesel Production Report Table 3, Feb. 26, 2021, https://www.eia.gov/biofuels/biodiesel/production/table3.pdf (accessed Dec. 14, 2021). Data were converted from mass to volume based on a specific gravity relative to water of 0.914 (canola oil), 0.916 (soybean oil), 0.916 (corn oil), 0.90 (tallow), 0.96 (white grease), 0.84 (poultry fat), and 0.91 (used cooking oil).
[104] DEIR 2-2. The Project percentage boost over existing biofuel feedstock consumption is from 48,000 b/d, divided by that 113,000 b/d from existing biodiesel production.
[105] This 372,000 b/d estimate is from two sources. First, data were taken from the U.S. Department of Agriculture (USDA) "Oil Crops Data: Yearbook Tables" data. U.S. Department of Agriculture (USDA), Oil Crops Yearbook Tables 5, 26, and 33, Mar. 26, 2021, https://www.ers.usda.gov/data-products/oil-crops-yearbook/ (accessed Dec. 14,

Thus, the Project alone would consume approximately a 13 percent share[106] of current total US production of lipid feedstocks. With that increase from the Project in place, U.S. biofuel feedstock demand could claim as much as 43 percent of total U.S. farm yield for *all* uses of these oils and fats. The Project alone would thus commit a disproportionate share of US food crop oils to California, with attendant potential climate consequences.[107]

The projected impact of the Project on the SBO markets is particularly notable. Existing biodiesel production uses approximately 66,000 b/d of SBO out of the total 203,000 b/d of SBO produced domestically for all uses.[108] As a result, the Project alone could use up to 24 percent of total domestic SBO production. This would constitute a rapid increase in domestic SBO consumption, which would dramatically outpace the recent year-on-year increases in domestic SBO production, ranging from 1-7%. This in turn would lead to rapid price spikes and substitution across the oil markets.

In order to assess the impacts of a "reasonable worst case" scenario, the County could, and should, have calculated the magnitude of the land use changes attributable to the anticipated feedstock mix. Had the County taken a closer look at the LCFS environmental assessment it cited, it could have readily used the same analysis conducted by CARB for the LCFS, as previously discussed in subsection A in order to quantify the upstream land use impacts of the Project's use of SBO feedstock. For example, under a hypothetical "shock" increase of 0.812 billion gallons / year of soy biodiesel, the GTAP-BIO model identified an average of over 2 million acres of forest, pasture, and cropland-pasture land would be converted to cropland. The

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2021). Specifically, from Oct. 2016 through Sep. 2020 average total U.S. yields were: 65.1 million pounds per day (MM lb/d), or 202,672 b/d at a specific gravity (SG) of 0.916 for soybean oil (*see* i below), 4.62 MM lb/d or 14,425 b/d at 0.915 SG for canola oil (ii), and 15.8 MM lb/d or 49,201 b/d at 0.923 SG for corn oil (iii).. *See* USDA Oil Crops Yearbook (OCY) data tables (i) OCY Table 5, (ii) OCY Table 26, (iii) OCY Table 33, (iv) OCY Table 20), (v) OCY Table 32. Second, we estimated total U.S. production of other animal fats and waste oils from the U.S. Department of Agriculture (USDA) "Fats and Oils: Oilseed Crushings, Production, Consumption and Stocks" Annual Summaries. National Agricultural Statistics Service, "Fats and Oils: Oilseed Crushings, Production, Consumption and Stocks Annual Summary", 2017 through 2020, https://usda.library.cornell.edu/concern/publications/mp48sc77c (accessed Dec. 14, 2021)., Specifically, from 2017 to 2020, average total U.S. yields were: 16.2 MM lb/d or 51,386 b/d for edible, inedible, and technical tallow production, 6.65 MM lb/d or 22,573 b/d for poultry fat production, 4.52 MM lb/d or 13,420 b/d for lard and choice white grease production, and 5.83 MM lb/d or 18,272 b/d for yellow grease production.

[106] This figure represents Project feedstock demand of 48,000 b/d over the estimated 372,000 b/d total lipid production in the U.S. calculated in the previous footnote.

[107] Importing biofuel feedstock from another state or nation which is needed there to help decarbonize its economy could make overreliance on biofuels to help decarbonize California's economy counterproductive as a climate protection measure. Accordingly, expert advice commissioned by state agencies suggests limiting the role of biofuels within the state's decarbonization mix to the state's per capita share of low-carbon biofuel feedstocks. *See* Mahone et al. 2020 and 2018. On this basis, given California and U.S. populations of 39.5 and 330 million, respectively, California's total share of U.S. farm production (for all uses) of plant oils and animal fats which also are used for biofuels would be approximately 12%. As described in the note above, however, the Project could commit 13% of that total U.S. yield (for all uses) to biofuels produced at the Refinery alone.

[108] U.S. Department of Agriculture (USDA) "Oil Crops Data: Yearbook Tables." Table 5 https://www.ers.usda.gov/data-products/oil-crops-yearbook/oil-crops-yearbook/#All%20Tables.xlsx?v=7477.4 (accessed Dec 12, 2021); U.S. Energy Information Administration (EIA). Monthly Biodiesel Production Report, Table 3. Inputs to biodiesel production; www.eia.gov/biofuels/biodiesel/production/table3.xls (accessed Dec 12, 2021). Soybean oil consumed for biodiesel production is an average of 2018 through 2020 data, while total U.S. production is an average from Oct. 2016 through Sept. 2020.

majority of this land use change would be overseas, with 1.2 million acres of the converted land use outside of the U.S.[109] While land use impacts will not necessarily be linear with the feedstock demand increases, this finding can be extrapolated to estimate the land use converted as a result of the Project. This finding, if scaled to the 0.74 billion gallons of feedstock consumed by the Project and if 100% of that feedstock was SBO, would mean 1.8 million acres of land would need to be converted for this Project.

E. Land Use Conversions Caused By the Project Will Have Significant Non-Climate Environmental Impacts

The land use changes incurred by increased use of feedstock supplies risk an array of environmental impacts related to habitats, human health, and indigenous populations.[110] Conversion of more natural habitat to cropland is often accompanied by efforts to boost short-term yields by applying more fertilizers and pesticides, thereby destroying habitat needed to reverse biodiversity loss. Indeed, authoritative international bodies have warned explicitly about the potential future severity of these impacts.[111] One path for creating additional crop lands is by burning non-agricultural forests and grasslands. This destructive process not only releases sequestered carbon, but also causes non-carbon related environmental impacts due to use of nitrogen-based fertilizers and petroleum-derived pesticides on the newly cleared lands; and use petroleum-fueled machinery to cultivate and harvest feedstock crops from newly converted land to meet crop-based biofuel demand.[112]

These non-climate environmental impacts were even identified by the 2018 LCFS Final EA as significant negative environmental impacts. CARB concluded that the agricultural, forest, and water resources related to land use changes related to feedstock cultivated would likely have significant negative effects, which are extraneous to the LCFS CI calculation. Adverse effects associated with the conversion or modification of natural land or existing agriculture include impacts on sensitive species populations; soil carbon content; annual carbon sequestration losses, depending on the land use; long-term erosion effects; adverse effects on local or regional water resources; and long-term water quality deterioration associated with intensified fertilizer use, pesticide or herbicide run-off; energy crops and short rotation forestry on marginal land, and intensive forest harvest could both have long-term effects on hydrology; agricultural activities may cause pollution from poorly located or managed animal feeding operations; pollutants that

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109 2018 CARB LCFS Staff Report Appendix I-8, I-29, I-30.

110 Malins, C., *Soy, land use change, and ILUC-risk: a review*, Cerulogy, 2020a, https://www.transportenvironment.org/wp-content/uploads/2021/07/2020_11_Study_Cerulogy_soy_and_deforestation.pdf; Malins, C. *Biofuel to the fire – The impact of continued expansion of palm and soy oil demand through biofuel policy*. Report commissioned by Rainforest Foundation Norway, 2020b. https://d5i6is0eze552.cloudfront.net/documents/RF_report_biofuel_0320_eng_SP.pdf (accessed Dec 8, 2021); Garr, R. and Karpf, S., BURNED: Deception, Deforestation and America's Biodiesel Policy, Action Aid USA, 2018. https://www.actionaidusa.org/publications/americas-biodiesel-policy/ (accessed Dec 8, 2021).

111 IPBES Summary for policymakers of the global assessment report on biodiversity and ecosystem services of the Intergovernmental Science-Policy Platform on Biodiversity and Ecosystem Services. IPBES: Bonn, DE, 2019, pp. 12, 18, 28. https://ipbes.net/global-assessment (accessed Dec 8, 2021);.

112 CARB 2018 LCFS Final EA, pp. 120, 172-173.

result from farming and ranching may include sediment, nutrients, pathogens, pesticides, metals, and salts; increased use of pesticides could increase greenhouse gas emissions.[113]

The expansion of palm oil production, due to SBO consumption as described above, will have a particularly severe environmental impact.[114] The palm oil industry is a source of pollutants and greenhouse gas emissions in two ways: deforestation and the processing of palm oil. Fires clearing the way for a palm oil plantation are a major source of air pollution that adversely affect human health; agrochemicals associated with biofuels are dangerous for terrestrial and aquatic ecosystems.[115] Palm oil production happens in biodiversity hotspots like Indonesia and the Brazilian Amazon, where massive deforestation and attendant species loss can dramatically affect both global biodiversity and the climate.[116]

F. Land Use Conversions Caused By the Project Will Have Significant Climate Impacts

The County failed to address evidence that increased use of food crop or food system feedstocks like palm and soybean oil have resulted in net increases in greenhouse gas emissions. As noted above, while the LCFS takes into account climate impacts resulting from land use change in its CI calculations, those calculations are expressly not intended to substitute for project-level analysis of impacts.

As described in the previous subsection, when the increased consumption of palm and soybean oil results in the clearing of more land or deforestation to grow more of those crops, it leads to the counterproductive destruction of natural carbon sinks. This expansion of soy production not only results in carbon loss from the destruction of vegetation and upheaval of high carbon stock soil, but also the loss of future sequestration capabilities. Available analysis suggests that a significant fraction of cropland expansion in general, and soy expansion in particular, continues to occur at the expense of carbon-sequestering forests, especially in South America.[117] Greenhouse gas emissions induced by land use changes from increased demand for food crop or food system-based feedstock also occur in the United States. One recent study concluded "perhaps surprisingly—that despite the dominance of grassland conversion in the US, emissions from domestic [land use change] are greater than previously thought."[118] More than 90% of emissions from grassland conversions came from soil organic carbon stocks (SOC).[119] Due to the longtime accumulation time of the SOCs, those emissions may be impossible to mitigate on a time scale relevant to humans.[120.]

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[113] CARB 2018 LCFS Final EA, pp. 110 – 120.

[114] *See* Petrenko, C., Paltseva, J., and Searle, S. *Ecological Impacts of Palm Oil Expansion in Indonesia*, International Council on Clean Transportation, Jul 2016. https://theicct.org/sites/default/files/publications/Indonesia-palm-oil-expansion_ICCT_july2016.pdf (accessed Dec 8, 2021);.

[115] *Id.,* pp. 7-11.

[116] *Id.*

[117] Malins 2019, pp. 5.

[118] Spawn, S. et al. Carbon emissions from cropland expansion in the United States Environ. Res. Lett. 14 045009, 2019. https://iopscience.iop.org/article/10.1088/1748-9326/ab0399 (accessed Dec 11, 2021).

[119] Spawn 2019, pp. 5.

[120] Spawn 2019, pp. 7, 9.

Domestic and global climate impacts from land use changes are interconnected because the feedstock are tied to a global food system. For example, even if the feedstock source is domestic, the increase in soybean oil demand will result in increases in palm oil production expansion as described above—ultimately resulting in substantial increases in GHG emissions.[121] As a result, modeled soy-based biofuel net carbon emissions are , at best, virtually the same as those from fossil diesel, with even worse climate impacts for greater quantities of soy-based biofuel produced.[122] These estimates suggest the DEIR has dramatically overstated the potential GHG benefits of the Project.

G. The County Should Have Taken Steps to Mitigate ILUC Associated with the Project by Capping Feedstock Use

The County should have considered a feedstock cap as a mitigation measure for land use impacts, but did not.[123] The one mitigating measure it did mention, best management practices (BMPs), has no meaningful application here.

Best Management Practices: Section 6.2 of the DEIR, concerning significant irreversible environmental changes, contains a brief high-level mention of Best Management Practices (BMPs) that can reduce agricultural impacts when used properly. DEIR at 6-3 *et seq.* However, the DEIR nowhere proposes BMPs as a mitigation measure. Indeed, without further specificity about the type and origins of potential feedstock, it is also impossible to know what types of BMPs are possible.

BMPs should, however, have been specifically included as a mitigation measure. The 2018 LCFS EA indicates that CARB anticipated local governments like the County to use their land use authority to mitigate projects by requiring feedstock sources to be developed under Best Management Practices specific to the ecological needs of feedstock origins. In particular, CARB left localities with land use authority to consider BMPs to mitigate long-term effects on hydrology and water quality related to changes in land use and long-term operational impacts to geology and soil associated with land use changes. [124]

Feedstock Cap: To guard against the severe environmental and climate impacts associated with the inevitably induced land use changes, the County should set capped feedstock volume, at a level that would prevent significant ILUC impacts, as already recommended by environmental advocates for California climate policy.[125] The DEIR should have considered

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[121] Malins, C. Driving deforestation: The impact of expanding palm oil demand through biofuel policy, 2018. http://www.cerulogy.com/wp-content/uploads/2018/02/Cerulogy_Driving-deforestation_Jan2018.pdf (accessed Dec 12, 2021); *see also* Malins 2020, pp. 57; *see* generally Searle 2018.
[122] Malins 2020a, pp. 57.
[123] *See e.g.*, Mitigation B.2.b: Agricultural and Forest Resource Impacts Related to Feedstock Cultivation; Mitigation Measure B.7.b Long-Term Operational Impacts to Geology and Soil Associated with Land Use Changes; Mitigation B.10.b: Long-Term Effects on Hydrology and Water Quality Related to Changes in Land Use, Mitigation B.11.b: Long-Term Operational Impacts on Land Use Related to Feedstock Production.
[124] *See* Mitigation Measure B.7.b Long-Term Operational Impacts to Geology and Soil Associated with Land Use Changes; Mitigation B.10.b: Long-Term Effects on Hydrology and Water Quality Related to Changes in Land Use.
[125] *See e.g.,* Martin et al., Union of Concerned Scientists Letter Re: 2022 Scoping Plan - Scenario Inputs Technical Workshop, Nov 10, 2021, pp. 3 ("_...CARB should ensure that future growth comes primarily from [non-lipid]

both caps on individual feedstocks, and an overall cap on feedstock volume. Such limits would be based on an ILUC assessment of each potential feedstock and total combinations of feedstock. In particular, the County should take steps to ensure that California does not consume a disproportionate share of available feedstock, in exceedance of its per capita share, in accordance with the prudent assumptions in CARB's climate modeling.[126]

V. THE DEIR FAILS TO ASSESS AND MITIGATE PROCESS SAFETY RISKS ASSOCIATED WITH RUNNING BIOFUEL FEEDSTOCKS[127]

The Scoping Comments described how processing vegetable or animal-derived biofuel feedstocks in a hydrotreater or hydrocracker creates significant refinery-wide process hazards beyond those that attend crude oil refining. That information was disregarded and not addressed in the DEIR. It is essential that the DEIR address the process safety risks described in the subsections below, and evaluate their potential impact on human health.

A. The Project Could Worsen Process Hazards Related to Exothermic Hydrogen Reactions

Running biofuel feedstocks risks additional process safety hazards even beyond those associated with processing crude oil. This is because the extra hydrogen that must be added to convert the new biofuel feedstock to hydrocarbon fuels generates more heat in process reactions that occur under high pressure and are prone to runaway reactions. The reaction is exothermic: it generates heat. When it creates more heat, the reaction can feed on itself, creating more heat even faster.[128]

The reason for the increased heat, and hence risk, is that the removal of oxygen from fatty acids in the biofuel feed, and saturating the carbon atoms in that feed to remove that oxygen without creating unwanted carbon byproducts that cannot be made into biodiesel and foul the process catalyst, require bonding that oxygen and carbon with a lot more hydrogen. The Project would use roughly nine times more hydrogen per barrel biorefinery feed than the average petroleum refinery needs from hydrogen plants per barrel crude.[129] Reacting more hydrogen

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feedstocks and directly constrain the consumption of lipid-based fuels at a level commensurate to the available feedstocks. In addition to an immediate constraint on the scale of lipid diversion to fuel markets, CARB should monitor the use of corn grain, various categories of biomass, electricity and hydrogen and ensure the scale of their use for fuel, energy or carbon removal uses does not exceed a sustainable level.")

[126] California Air Resources Board, PATHWAYS Biofuel Supply Module, Technical Documentation for Version 0.91 Beta, Jan 2017, pp. 9 https://ww2.arb.ca.gov/sites/default/files/classic/cc/scopingplan/bfsm_tech_doc.pdf (accessed Dec 12, 2021).

[127] Supplemental information in support of this analysis is provided in Karras 2021c accompanying this comment, in the section entitled "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."

[128] Robinson and Dolbear, "Commercial Hydrotreating and Hydrocracking. *In* Hydroprocessing of heavy oils and residua," 2007. Ancheyta and Speight, eds. CRC Press, Taylor and Francis Group: Boca Raton, FL, pp. 308, 309.

[129] The Project could consume 2,220–3,020 standard cubic feet of H_2 per barrel of biomass feed processed. Karras, 2021a. *Changing Hydrocarbons Midstream* (attached hereto). Operating data from U.S. petroleum refineries during 1999–2008 show that nationwide petroleum refinery usage of hydrogen production plant capacity averaged 272 cubic feet of H_2 per barrel crude processed. Karras, 2010. *Environ. Sci. Technol.* 44(24): 9584 and Supporting Information. (*See* data in Supporting Information Table S-1.) https://pubs.acs.org/doi/10.1021/es1019965.

over the catalyst in the hydrotreating or hydrocracking reactor generates more heat faster.[130] This is a well-known hazard in petroleum processing, that manifests frequently in flaring hazards[131] when the contents of high-pressure reactor vessels must be depressurized[132] to flares in order to avoid worse consequences that can and sometimes have included destruction of process catalyst or equipment, dumping gases to the air from pressure relief valves, fires and explosions. The extra hydrogen reactants in processing the new feedstocks increase these risks.[133]

B. The Project could Worsen Process Hazards Related to Damage Mechanisms Such as Corrosion, Gumming, and Fouling

The severe processing environment created by the processing of new feedstocks for the Project also can be highly corrosive and prone to side reactions that gum or plug process flows, leading to frequent or even catastrophic equipment failures. Furthermore, depending on the contaminants and processing byproducts of the particular Project feedstock chosen, it could create new damage mechanism hazards or exacerbate existing hazards to a greater degree. As one researcher notes:

> Feedstock that is high in free fatty acids, for example, has the potential to create a corrosive environment. Another special consideration for renewable feedstocks is the potential for polymerization ... which causes gumming and fouling in the equipment ... hydrogen could make the equipment susceptible to high temperature hydrogen attack ... [and drop-in biodiesel process] reactions produce water and carbon dioxide in much larger quantities than petroleum hydrotreaters, creating potential carbonic acid corrosion concerns downstream of the reactor.[134]

C. Significant Hazard Impacts Appear Likely Based on Both Site-Specific and Global Evidence

Site-specific evidence shows that despite current safeguards, hydrogen-related hazards frequently contributed to significant flaring incidents, even before the worsening of hydro-conversion intensity and hydrogen-related process safety hazards which could result from the Project. Causal analysis reports for significant flaring from unplanned incidents indicate that at least 49 hydrogen-related process safety hazard incidents occurred at the Refinery from January

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[130] van Dyk et al., 2019. *Biofuels Bioproducts & Biorefining* 13: 760–775. *See* p. 765 ("exothermic reaction, with heat release proportional to the consumption of hydrogen"). https://onlinelibrary.wiley.com/doi/10.1002/bbb.1974.

[131] Flaring causal analyses, various dates. Reports required by Bay Area Air Quality Management District Regulation 12, Rule 12, including reports posted at https://www.baaqmd.gov/about-air-quality/research-and-data/flare-data/flare-causal-reports and reports for incidents predating those posted at that link.

[132] 22 Chan, E., 2020. Converting a Petroleum Diesel Refinery for Renewable Diesel; White Paper /- Renewable Diesel. Burns McDonnell. www.burnsmcd.com/insightsnews/tech/converting-petroleum-refinery-for-renewable-diesel. (Chan, 2020) *See* p. 2 ("emergency depressurization" capacity required).

[133] van Dyk et al., 2019 ("heat release proportional to the consumption of hydrogen"); and Chan, 2020 at 2 ("significantly more exothermic than petroleum diesel desulfurization reactions").

[134] Chan, 2020.

2010 until it closed on 28 April 2020.[135] This is a conservative estimate, since incidents can cause significant impacts without environmentally significant flaring, but still represents, on average, another hydrogen-related hazard incident at the Refinery every 77 days. Considering both the Refinery and the Phillips 66 rodeo facility data together during this period, sudden unplanned or emergency shutdowns of major hydro-conversion or hydrogen production plants occurred in 84 of these reported incidents.[136] Such sudden forced shutdowns of *both* hydro-conversion and hydrogen production plants occurred in 22 of these incidents.[137] In other words, incidents escalated to refinery-level systems involving multiple plants frequently—a foreseeable consequence since 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 three of these incidents, consequences of underlying hazards included fires at the Refinery.[138]

Catastrophic consequences of hydrogen-related hazards are foreseeable based on industry-wide reports as well as site-specific evidence. For example:

- Eight workers are injured and a nearby town is evacuated in a 2018 hydrotreater reactor rupture, explosion and fire;[139]
- A worker is seriously injured in a 2017 hydrotreater fire that burns for two days and causes an estimated $220 million in property damage;[140]
- A reactor hydrogen leak ignites in a 2017 hydrocracker fire that causes extensive damage to the main reactor;[141]
- A 2015 hydrogen conduit explosion throws workers against a refinery structure;[142]
- Fifteen workers die, and 180 others are injured, in a series of 2005 explosions when hydrocarbons flood a distillation tower during an isomerization unit restart;[143]
- 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;[144]
- A worker dies, 46 others are injured, and the surrounding community is forced to 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 Refinery;[145]

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[135] Flaring causal analyses, various dates. Reports required by Bay Area Air Quality Management District Regulation 12, Rule 12, including reports posted at https://www.baaqmd.gov/about-air-quality/research-and-data/flare-data/flare-causal-reports and reports for incidents predating those posted at that link.
[136] Flaring causal analyses as cited above. Hydro-conversion includes hydrotreating and hydrocracking.
[137] *Id.*
[138] Flaring causal analyses as cited above. *See* reports for incidents starting 13 May 2010, 17 February 2011 and 17 April 2015.
[139] Process Safety Integrity, *Refining incidents;* https://processsafetyintegrity.com/incidents/industry/refining ; *see* Bayernoil Refinery Explosion, January 2018.
[140] Process Safety Integrity as cited above; *see* Syncrude Fort McMurray Refinery Fire, March 2017.
[141] Process Safety Integrity as cited above; *see* Sir Refinery Fire, January 2017.
[142] Process Safety Integrity as cited above; *see* Petrobras (RLAM) Explosion, January 2015.
[143] Process Safety Integrity as cited above; *see* BP Texas City Refinery Explosion, March 2005.
[144] Process Safety Integrity as cited above; *see* Chevron (Richmond) Refinery Explosion, March 1999.
[145] Process Safety Integrity as cited above; *see* Tosco Avon (Hydrocracker) Explosion, January 1997.

- 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;[146]
- A high-pressure hydrogen line fails in a 1989 fire which buckles the seven-inch-thick steel of a hydrocracker reactor that falls on nearby Richmond refinery equipment;[147]
- An undetected vessel overpressure causes a 1987 hydrocracker explosion and fire.[148]

Since the Project's new feedstock and process system are thus known to worsen the underlying conditions that can become (and have become) root causes of hazardous incidents, the DEIR should have disclosed, thoroughly evaluated, and mitigated these risks. The DEIR should have analyzed, *inter alia,* the impact of the proposed new feedstock and production process on worker safety, community safety, and upset frequency and impacts (including increased flaring – *see* Section VII).

D. Process Operation Mitigation Measures Can Reduce but Not Eliminate Process Safety Hazard Impacts

There are procedures to control the reaction heat, pressure – including through process operation measures such as quenching between catalyst beds in the reactor and careful control of how hot the reactor components get, how much hydrogen is added, how much feed is added, and how long the materials remain in the reactor, preventing hot spots from forming inside of it, and intensive monitoring for equipment damage and catalyst fouling. These measures should have been considered in the DEIR as mitigation for process safety impacts, but were not.

However, such analysis would also need to account for the fact that these measures they are imperfect at best, and rely on both detailed understanding of complex process chemistry and monitoring of conditions in multiple parts of the process environment. Both those conditions are difficult to attain in current petroleum processing, and even more difficult with new feedstocks with which there is less current knowledge about the complex reactions and how to monitor them when the operator cannot "see" into the reactor very well during actual operation; and cannot meet production objectives if production is repeatedly shut down in order to do so.

In fact, the measures described above are "procedural safeguards,"[149] the least effective type of safety measure in the "Hierarchy of Hazard Control"[150] set forth in California process safety management policy for petroleum refineries.[151] Marathon itself added automated

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[146] Process Safety Integrity as cited above; *see* Carson Refinery Explosion, October 1992.
[147] Process Safety Integrity as cited above; *see* Chevron (Richmond) Refinery Fire, April 1989.
[148] Process Safety Integrity as cited above; *see* BP (Grangemouth) Hydrocracker Explosion, March 1987.
[149] Procedural safeguards are policies, operating procedures, training, administrative checks, emergency response and other management approaches used to prevent incidents or to minimize the effects of an incident. Examples include hot work procedures and emergency response procedures. California Code of Regulations (CCR) § 5189.1 (c).
[150] This Hierarchy of Hazard Control ranks hazard prevention and control measures "from most effective to least effective [as:] First Order Inherent Safety, Second Order Inherent Safety, and passive, active and procedural protection layers." CCR § 5189.1 (c).
[151] We note that to the extent this state policy, the County Industrial Safety Ordinance, or both may be deemed unenforceable with respect to biorefineries which do not process petroleum, that only further emphasizes the need for full analysis of Project hazard impacts and measures to lessen or avoid them in the DEIR.

shutdown control logic systems to these procedural safeguards before it closed the refinery, but these are "active safeguards,"[152] the next least effect type of safety measure in the Hierarchy of Hazard Control. Marathon now proposes to replace some of the vessel and piping linings of its old Refinery equipment, which would be repurposed for the Project, with more corrosion-resistant metallurgy—an added layer of protection in those parts of the biorefinery where this proposal might be implemented, and a tacit admission that potential hazards of processing its proposed feedstock are a real concern. This type of measure is a "passive safeguard,"[153] the next least effective type of measure in the Hierarchy of Hazard Control, after procedural and active safeguards. Marathon has not proposed more effective first or second order inherent safety measures for the specific Project hazards identified above.

Importantly, and perhaps most telling, Marathon proposes to repurpose and continue to use the flare system of its closed refinery for this Project. DEIR at 2-22. Rather than eliminating underlying causes of safety hazard incidents or otherwise preventing them, refinery flare systems are designed to be used in procedures that minimize the effects of such incidents.[154] This is a procedural safeguard, again the least effective type of safety measure.[155] The flares would partially mitigate incidents that, in fact, are expected to occur if the Project is implemented, but flaring itself causes acute exposure hazards. And as incidents caused by underlying hazards that have not been eliminated continue to recur, they can eventually escalate to result in catastrophic consequences.

E. The DEIR Should Have Evaluated the Potential for Deferred Mitigation of Process Hazards

The DEIR should have considered available means to address the Project design, and impose appropriate conditions and limitations, to mitigate process safety hazards. Examples of potential mitigation measures that should have been considered (in addition to the process measures referenced above of limited effectiveness) include 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 and some HEFA feedstocks increase process hydrogen demand significantly more than other others, 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, would thereby lessen or avoid further intensified hydrogen reaction hazard impacts.

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[152] Active safeguards are controls, alarms, safety instrumented systems and mitigation systems that are used to detect and respond to deviations from normal process operations; for example, a pump that is shut off by a high-level switch. CCR § 5189.1 (c).
[153] See CCR § 5189.1 (c).
[154] *See* BAAQMD regulations, § 12-12-301. Bay Area Air Quality Management District: San Francisco, CA.
[155] *See* Procedural Measure and Hierarchy of Hazard Control definitions under CCR § 5189.1 (c) in the notes above.

- *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.

Commenters are not necessarily recommending these particular measures. However, these and any other options for mitigating process hazards through design or other conditions should have been considered, and were not.

VI. THE DEIR INADEQUATELY DISCLOSES AND ADDRESSES PROJECT GREENHOUSE GAS AND CLIMATE IMPACTS

The DEIR analysis of greenhouse gas (GHG) emissions and climate impacts suffers from the same baseline-related flaw as numerous other subjects in the document, *i.e.*, it determines emission impacts from a baseline of continuing crude oil production as opposed to actual current shutdown conditions. Based on the flaw alone, the DEIR analysis of GHG emissions impacts must be revised to incorporate the correct baseline.

However, even aside from this major flaw, the DEIR's analysis of GHG and climate impacts is deficient. The document identifies as significance criteria both (1) whether the Project would generate significant GHG emissions, and (2) whether it would "conflict with an applicable plan, policy or regulation adopted for the purpose of reducing the emissions of GHG." DEIR at 3.8-19. The DEIR fails to adequately evaluate the first significance criterion because it fails to account for potentially increased GHG emissions associated with the processing of varying biofuel feedstocks. It also fails to adequately evaluate the second significance criterion, because it ignores the potential downstream impact of a significant increase in biofuel production on state and local climate goals. As noted in the Scoping Comments but not addressed in the DEIR at all, those goals include an increase in use of battery electric vehicles to electrify the state's transportation sector and decrease use of combustion fuels[156]; as well as a "Diesel Free by '33" pledge promoted by BAAQMD and entered into by Contra Costa County, which commits the County to, *inter alia,* "[u]se policies and incentives that assist the private sector as it moves to diesel-free fleets and buildings."[157] The DEIR further fails to identify the significant shifting of GHG emissions from California to other jurisdictions that would likely occur as a consequence of the Project.

The following sections address the various potential conflicts between the Project and state and local plans, policies, and regulations adopted for the purpose of reducing GHG

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[156] Executive Order N-79-20 dated September 23, 2020, *available at* https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-text.pdf.
[157] *See* https://dieselfree33.baaqmd.gov/ (landing page), https://dieselfree33.baaqmd.gov/statement-of-purpose (text of the pledge), https://dieselfree33.baaqmd.gov/signatories (signatories).

emissions that render the Project's impacts potentially significant, but which the DEIR nonetheless failed to consider.

A. The DEIR Air Impacts Analysis Fails to Take Into Account Varying GHG Emissions from Different Feedstocks and Crude Slates

The following subsections discuss ways in which project GHG emissions vary widely with feedstock choice, as well as reasons why those emissions may increase rather than decrease over the comparable crude oil refining emissions.

1. Processing Biofuel Feedstock Instead of Crude Oil Can Increase Carbon Emission Intensity of the Refining Process

The DEIR did not address the fact that the process of refining biofuel feedstocks is significantly more carbon intense than crude oil refining. This increased carbon intensity has primarily to do with the fact that HEFA feedstocks have vastly more oxygen in them than crude oil – and hence require more hydrogen production to remove that oxygen. The oxygen content of the various proposed Project feedstocks is approximately 11 wt. % (Table 6), compared with refining petroleum crude, which has virtually no oxygen. Oxygen would be forced out of the HEFA feedstock molecules by bonding them with hydrogen to make water (H_2O), which then leaves the hydrocarbon stream. This process consumes vast amounts of hydrogen, which must be manufactured in amounts that processing requires. The deoxygenation process chemistry further boosts HEFA process hydrogen demand by requiring saturation of carbon double bonds.

These "hydrodeoxygenation" (HDO) reactions are a fundamental change from petroleum refining chemistry. This new chemistry is the main reason why—despite the "renewable" label Marathon has chosen—its biorefinery could emit more carbon per barrel processed than petroleum refining. That increase in the carbon intensity of fuels processing would be directly connected to the proposed change in feedstock.

Table 6. Impact of Project Feedstock Choice on CO_2 Emissions from Hydrogen Production for Marathon Project Targeting Diesel: Estimates based on readily available data.

t/y: metric tons/year **kg:** kilogram **b:** barrel, 42 U.S. gallons

	Feedstock			Difference	
	Tallow	**Soy oil**	**Fish oil**	**Soy oil–tallow**	**Fish oil–tallow**
Processing characteristics [a]					
Oxygen content (wt. %)	11.8	11.5	11.5	– 0.3	– 0.3
H_2 for saturation (kg H_2/b)	0.60	1.58	2.08	+ 0.98	+ 1.48
H_2 for deoxygenation (kg H_2/b)	4.11	4.11	4.13	0.00	+ 0.02
Other H_2 consumption (kg H_2/b)	0.26	0.26	0.26	0.00	0.00
Process H_2 demand (kg H_2/b)	4.97	5.95	6.47	0.98	1.50
Hydrogen plant emission factor					
HEFA mixed feed (g CO_2/g H_2) [a]	9.82	9.82	9.82		
Methane feed (g CO_2/g H_2) [b]	9.15	9.15	9.15		
Hydrogen plant CO_2 emitted					
HEFA mixed feed (t/y) [a]	855,000	1,020,000	1,110,000	165,000	255,000
Methane feed (t/y) [b]	797,000	954,000	1,040,000	157,000	243,000

a. Data from HEFA feedstock-specific composition analysis based on multiple feed measurements, process analysis for HEFA hydro-conversion process hydrogen demand, and emission factor based on median SF Bay Area hydrogen plant verified design performance and typical expected HEFA process hydrogen plant feed mix. From Karras, 2021b. *See* also Karras, 2021a.
b. Data from Sun et al. for median California merchant steam methane reforming hydrogen plant performance. Sun et al., 2019. Criteria Air Pollutants and Greenhouse Gas Emissions from Hydrogen Production in U.S. Steam Methane Reforming Facilities. Environ. Sci. Technol. 53: 7103–7113. https://pubs.acs.org/doi/10.1021/acs.est.8b06197 Note that these steam methane reforming plant data are shown for context. Steam reforming of HEFA byproduct propane can be expected to increase direct emissions from the steam reforming and shift reactions. Karras, 2021a. Mass emissions based on 48,000 b/d project capacity. Fish oil values shown are based on menhaden.

Hydrogen must be added to bond with oxygen in HEFA feeds and thereby remove the oxygen in them, and to bond with carbon atoms in fatty acids in order to facilitate this deoxygenation of the feed carbon chains converted to hydrocarbons. This increases the hydrogen needed for the proposed HEFA[158] processing over and above the hydrogen that was needed for the crude refining that formerly took place at the Refinery. Deoxygenation is the major driver of this high process hydrogen demand, but HEFA feeds are consistently high in hydrogen, while some have more carbon double bonds that must be "saturated" first, and thus higher saturation hydrogen demand, than other feeds. Table 6 shows both of these things.

The DEIR – to the extent it considers past petroleum refining emissions in its analysis – must consider the air emissions impact of increased hydrogen use. Oxygen-rich HEFA feedstocks force increased hydrogen production – and attendant hydrogen production emissions -- by a proportional amount. These emissions are significant, because Marathon proposes to make that hydrogen in existing fossil fuel hydrogen plants. This hydrogen steam reforming technology is extremely carbon intensive. It burns a lot of fuel to make superheated high-pressure steam mixed with hydrocarbons at temperatures up to 1,400–1,900 ºF. And on top of those combustion emissions, its "reforming" and "shift" reactions produce hydrogen by taking it

[158] As noted in previous sections, the type of drop-in biofuel technology proposed is called "Hydrotreating Esters and Fatty Acids" (HEFA).

from the carbon in its hydrocarbon feed. That carbon then bonds with oxygen to form carbon dioxide (CO_2) that emits as well. Making the vast amounts of hydrogen needed for project processing could cause CO_2 emissions from project hydrogen plants alone to exceed a million tons each year.

The resulting carbon intensity difference between crude oil refining and biofuel refining is striking. CO_2 emissions from U.S. petroleum refineries averaged 41.8 kg per barrel crude feed from 2015-2017 (the most recent data available).[1] By contrast, HEFA production emits 55-80 kg per barrel biomass feed associated with increased hydrogen production *alone* – such exceeding petroleum refining carbon intensity by 32-91 percent. Beyond the hydrogen-production driver of increased carbon intensity, additional CO_2 would emit from fuel combustion for energy to heat and pressure up HEFA hydro-conversion reactors, precondition and pump their feeds, and distill, then blend their hydrocarbon products.[159]

2. <u>GHG Emissions Impacts Vary With Different Potential Feedstocks</u>

Crucially, feeds that the project targets, such as tallow and SBO - and some that it does not but may nonetheless potentially use such as fish oil - require hydrogen for processing to significantly different degrees. Table 6 shows this difference in weight percent, a common measure of oil feed composition. The 0.98 kilograms per barrel feed difference in hydrogen saturation between soy oil and tallow is why processing soy oil requires that much more hydrogen per barrel of project feed (0.98 kg H_2/barrel). Table 6. Similarly, the 1.48 kg/b difference between saturating fish oil and tallow requires 1.48 more kilograms of hydrogen per barrel to make so-called “renewable” diesel from fish oil than to make it from tallow. *Id.*

Thus, feedstock choice would drive the magnitude of carbon emissions to a significant degree. *Id.* For instance, to the extent Marathon runs SBO, Project hydrogen plants could emit approximately 165,000 metric tons more CO_2 each year than if it runs tallow. *Id.* This 165,000 t/y excess would exceed the emissions significance threshold for greenhouse gases in the DEIR, 10,000 metric tons/year CO_2e (DEIR at 3.8-16) by *15 times.* And if Marathon were to run fish oil, another potential feedstock not specifically targeted but also not excluded, the estimates in Table 6 suggest that Project hydrogen plants could emit 255,000 tons/year more CO_2 than if it runs tallow, or *24 times* that significance threshold. Thus, available evidence indicates that the choice among project feedstocks itself could result in significant emission impacts. Therefore, emissions from each potential feedstock should be estimated in the EIR.

The CO_2 emissions estimates in Table 6 are relatively robust and conservative, though the lack of project specific-details disclosed in the DEIR described in Section II still raises questions a revised County analysis should answer. The carbon intensity estimate for HEFA hydrogen production is remarkably close that for steam methane reforming, as expected since hydrocarbon byproducts of HEFA refining, when mixed with methane in project hydrogen plants, would form

[159] Karras, 2021. Unverified potential to emit calculations provided by one refiner[1] suggest that these factors could add ~21 kg/b to the 55-80 kg/b from HEFA steam reforming. This ~76–101 kg/b HEFA processing total would exceed the 41.8 kg/b carbon intensity of the average U.S. petroleum refinery by ~82-142 percent. Repurposing refineries for HEFA biofuels production using steam reforming would thus increase the carbon intensity of hydrocarbon fuels processing. *See* supporting material for Karras, 2021a.

more CO_2 per pound of hydrogen produced than making that hydrogen from methane alone. The estimate may indeed turn out to be too low, given the variability in hydrogen plant emissions generally,[160] the tendency of older plant designs to be less efficient and higher-emitting, and since the Marathon No. 1 Hydrogen Plant design is a 1963 vintage.[161] The DEIR should have evaluated this part of Project processing emissions using data for the Marathon and Air Products hydrogen plants that would be used by the Project; and Marathon should have been required to provide detailed data on those plants to support this estimate.

Feedstock choices can impact other greenhouse gases as well through varying hydrogen demand. In addition to the potential for feedstock-driven increases in emissions of CO_2, the proposed hydrogen production would emit methane, a potent greenhouse gas that also contributes to ozone formation, via "fugitive" leaks or vents. Aerial measurements and investigations triggered by those recent measurements suggest, further, that methane emissions from hydrogen production have been underestimated dramatically.[162]

Crucially as well, making a different product slate can increase GHG emissions from the same feedstock. This is why, for example, the California Air Resources Board estimates a different carbon intensity for refining gasoline, diesel, or jet fuel from the same crude feed. It is relevant because, although Marathon originally said that the project would target drop-in biodiesel, it could switch to target jet fuel production. Indeed, Marathon hinted recently that it may do so.[163] Available evidence suggests that targeting jet fuel instead of drop-in diesel production from the same vegetable oil or animal fat feed could increase processing emissions significantly.[164] Thus, since differences between potential project feedstocks and project products could each increase emissions independently or in combination, the DEIR should have estimated emissions for each potential project feedstock for product slates targeting both diesel and jet fuel.

Thus, processing emissions of GHGs should have been estimated in the DEIR for each potential project feedstock and product slate, or range of product slates, proposed to be manufactured from it, including a reasonable worst case scenario.

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[160] Sun et al., 2019. Criteria Air Pollutants and Greenhouse Gas Emissions from Hydrogen Production in U.S. Steam Methane Reforming Facilities. Environ. Sci. Technol. 53: 7103–7113. https://pubs.acs.org/doi/10.1021/acs.est.8b06197 .

[161] BAAQMD Source S-1005. *See* Application 28789 File, submitted to the Bay Area Air Quality Management District (BAAQMD) by Tosco Corp. on 9 Sep 1982 for permits regarding this refinery now owned by Marathon. *See* esp. Form G for Source S-1005 as submitted by M. M. De Leon, Tosco Corp., on 11/12/82.

[162] Guha et al., 2020. *Environ. Sci. Technol.* 54: 9254–9264 and Supporting Information. https://dx.doi.org/10.1021/acs.est.0c01212

[163] Compare January 29, 2021 draft Project Description at 1-1 ("including renewable diesel, renewable propane, renewable naphtha, *and potentially renewable jet*") (emphasis added) with October 2020 Project Description at 1-1 ("including renewable diesel, renewable propane, and renewable naphtha"). We note in this regard that as stated in its title, the preliminary estimates in Table 2 are based on the conversion of Project feedstocks into diesel, not jet fuel. Emissions from jet fuel production could be significantly higher.

[164] Seber et al., 2014. *Biomass and Bioenergy* 67: 108–118. http://dx.doi.org/10.1016/j.biombioe.2014.04.024. *See* also Karatzos et al., 2014. Report T39-T1, IEA Bioenergy Task 39. IEA ISBN: 978-1-910154-07-6. (*See* esp. p. 57; extra processing and hydrogen required for jet fuel over diesel.) https://task39.sites.olt.ubc.ca/files/2014/01/Task-39-Drop-in-Biofuels-Report-FINAL-2-Oct-2014-ecopy.pdf. *See also* Karras, 2021b.

B. The DEIR Failed to Consider the Impact of Biofuel Oversupply on Climate Goals

California has implemented a series of legislative and executive actions to reduce greenhouse gas emissions (GHGs) and address climate change. Two flagship bills were aimed at directly reducing GHG emissions economy wide: AB32, which called for reductions in GHG emissions to 1990 levels by 2020;[165] and SB32, which calls for reductions in GHG emissions to 40% below 1990 levels by 2030.[166] Following this, California Executive Order S-3-05 calls for a reduction in GHG emissions to 80% below 1990 levels by 2050.[167] Finally, Executive Order B-55-18 calls for the state "to achieve carbon neutrality as soon as possible, but no later than 2045, and achieve and maintain net negative emissions thereafter."[168]

In order to meet these legislative and executive imperatives, numerous goals have been set to directly target the state's GHG emissions just in the last two years: for 100% of light-duty vehicle (LDV) sales to be zero-emission vehicles (ZEVs) by 2035; for 100% of medium- and heavy-duty vehicle (MDV and HDV) sales to be ZEVs by 2045;[169] for a ban on hydraulic fracturing by 2024; and for an end to all state oil drilling by 2045.

Such goals, both the ZEV sales mandates that target liquid combustion fuel demand and the proposed bans on petroleum extraction that target supply, point to the need to transition from petroleum-based transportation fuels to sustainable alternatives. The DEIR frames biofuels as a means to reduce reliance on "traditional" transportation fuels, the original purpose of the LCFS. DEIR at 3.8-13. It insists that this Project is a necessary fulfillment of the 2017 Scoping Plan and LCFS. DEIR at 3.8-22. However, the 2017 Scoping Plan targets do not distinguish between fuel technologies (e.g. HEFA v. Fischer-Tropsch) or feedstock (crop-based lipid v. cellulosic). Yet feedstock and technology make a significant difference on GHG emissions. If anything, the environmental analysis of the 2017 Scoping Plan, like that of the LCFS, predicted that crop-based biofuels would need additional project-specific environmental analysis and mitigation.[170] This cursory invocation of the LCFS fails to address the problem of biofuel volume: too much biofuel production risks interfering with the ZEV goals most recently established by Governor Newsom. The overproduction problem is related in part to the higher carbon intensity of biofuel refining as compared to oil refining, and in part to its volume effects on the types, amounts, and locations of both zero-emission and petroleum fuels production and use. This problem of overproduction is not addressed in the LCFS. The LCFS, designed to establish incremental per-

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[165] Legislative Information, AB-32, California Global Warming Solutions Act of 2006 (Accessed November 29, 2021), http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.html

[166] Legislative Information, SB-32 California Global Warming Solutions Act of 2006: Emissions Limit, (Accessed November 29, 2021), from https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB32

[167] Executive Order S-3-05. Executive Department, State of California, Arnold Schwarzenegger, Governor, State of California; https://www.library.ca.gov/wp-content/uploads/GovernmentPublications/executive-order-proclamation/5129-5130.pdf.

[168] Executive Order B-55-18. Executive Department, State of California, Edmund Brown, Governor, State of California; https://www.ca.gov/archive/gov39/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf.

[169] Executive Order N-79-20. Executive Department, State of California, Gavin Newsom, Governor, State of California; https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-Climate.pdf

[170] California Air Resources Board. Appendix F: Final Environmental Analysis for The Strategy for Achieving California's 2030 Greenhouse Gas Target, pp. 56, https://ww2.arb.ca.gov/sites/default/files/classic/cc/scopingplan/2030sp_appf_finalea.pdf. .

barrel impacts, is not set up to address the macro impact of overproduction of combustion fuels on California climate goals.

In numerous state-sponsored studies, there is acknowledgment of the need to limit our biofuel dependence. These studies consistently demonstrate that California's climate goals require a dramatic reduction in the use of *all* combustion fuels in the state's transportation sector, not just petroleum-based fuels. They indicate the need for biofuel use to remain limited. Specifically, pathway scenarios developed by Mahone et al. for the California Energy Commission (CEC),[171] Air Resources Board (CARB)[172] and Public Utilities Commission,[173] Austin et al. for the University of California,[174] and Reed et al. for UC Irvine and the CEC[58] add semi-quantitative benchmarks to the 2050 emission target for assessing refinery conversions to biofuels. They join other work in showing the need to decarbonize electricity and electrify transportation.[175] Their work evaluates a range of paths to state climate goals,[176] analyzes the roles of liquid hydrocarbon combustion fuels and hydrogen in this context,[177] and addresses potential biomass fuel chain effects on climate pathways.[178]

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[171] Mahone et al., 2018. *Deep Decarbonization in a High Renewables Future: Updated results from the California PATHWAYS Model;* Report CEC-500-2018-012. Contract No. EPC-14-069. Prepared for California Energy Commission. Final Project Report. Energy and Environmental Economics, Inc.: San Francisco, CA. https://ww2.energy.ca.gov/2018publications/CEC-500-2018-012/CEC-500-2018-012.pdf

[172] Mahone et al., 2020. Achieving Carbon Neutrality in California: Pathways Scenarios Developed for the California Air Resources Board, California Air Resources Board, Energy and Environmental Economics, Inc. https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_report_oct2020_0.pdf.

[173] Mahone et al., 2020b. *Hydrogen Opportunities in a Low-Carbon Future: An Assessment of Long-Term Market Potential in the Western United States;* Energy and Environmental Economics, Inc.: San Francisco, CA. Report prepared for ACES, a joint development project between Mitsubishi Hitachi Power Systems Americas, Inc. and Magnum Development, LLC. Submitted to the California Public Utilities Commission June 2020. https://www.ethree.com/?s=hydrogen+opportunities+in+a+low-carbon+future

[174] Austin et al., 2021. *Driving California's Transportation Emissions to Zero;* Report No.: UC-ITS-2020-65. Institute of Transportation Studies, University of California. DOI: 10.7922/G2MC8X9X. https://escholarship.org/uc/item/3np3p2t0

[175] Mahone et al 2018; Mahone et al. 2020a; Mahone et al. 2020b; Austin et al. 2021; Reed et al., 2020. *Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California;* Final Project Report CEC-600-2020-002. Prepared for the California Energy Commission by U.C. Irvine Advanced Power and Energy Program. Clean Transportation Program, California Energy Commission: Sacramento, CA. https://efiling.energy.ca.gov/getdocument.aspx?tn=233292; Williams et al., 2012. The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity. *Science* 53–59. https://doi.org/DOI:10.1126/science.1208365; Williams et al., 2015. Pathways to Deep Decarbonization in the United States; The U.S. report of the Deep Decarbonization Pathways Project of the Sustainable Development Solutions Network and the Institute of Sustainable Development and International Relations. Revision with technical supp. Energy and Environmental Economics, Inc., in collaboration with Lawrence Berkeley National Laboratory and Pacific Northwest National Laboratory. https://usddpp.org/downloads/2014-technical-report.pdf; Williams et al., 2021. Carbon-Neutral Pathways for the United States. *AGU Advances* 2, e2020AV000284. https://doi.org/10.1029/2020AV000284.

[176] Mahone et al. 2020a.

[177] Mahone et al. 2018; Mahone et al. 2020a; Mahone et al. 2020b; Austin et al. 2020; Reed et al. 2020.

[178] Mahone et al. 2018; Mahone et al. 2020a; Reed et al. 2020.

Mahone's study prepared for CARB explored three scenarios for achieving carbon neutrality by 2045.[179] The scenarios include "The Zero Carbon Energy scenario" which would achieve zero-fossil fuel emission by 2045 with minimal use of carbon dioxide removal (CDR) strategies, "The High CDR scenario" which would achieve an 80% reduction in gross GHG emissions by 2045 but relies heavily on CDR, and "The Balanced scenario" which serves as a midpoint between the other two scenarios. Notably, all three of these pathways cut liquid petroleum fuel use dramatically, with biofuels replacing only a portion of that petroleum. Chart 1 illustrates the transportation fuel mix for these three pathways:

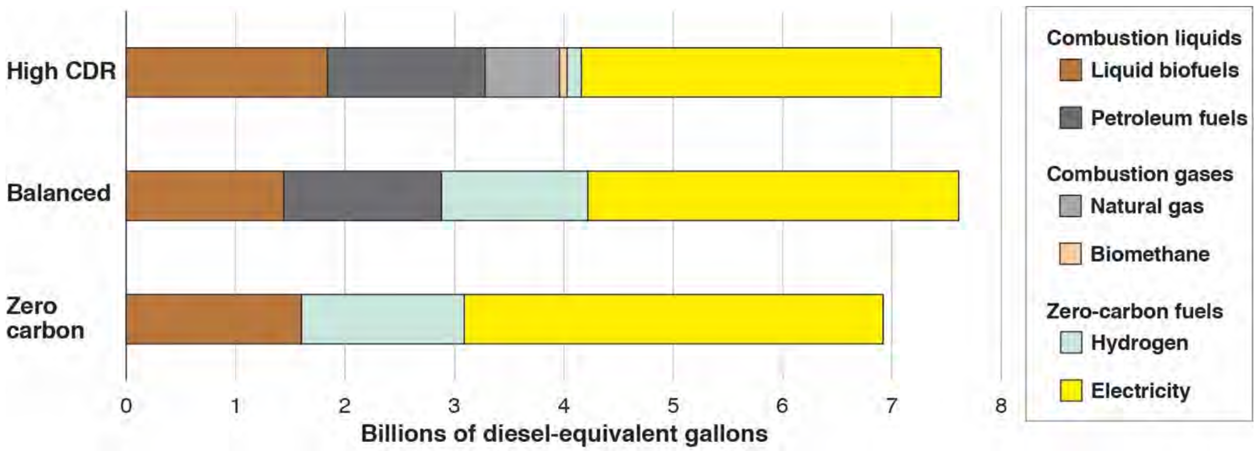

Chart 1: California Transportation Fuels Mix in 2045: Balanced and "bookend" pathways to the California net-zero carbon emissions goal.
Adapted from Figure 8 in Mahone et al. (2020).[180] Fuel shares converted to diesel energy-equivalent gallons based on Air Resources Board LCFS energy density conversion factors. **CDR:** carbon dioxide removal (sequestration).

Total liquid hydrocarbon combustion fuels for transportation in 2045, including both petroleum and biofuels, range among the pathways from approximately 1.6 to 3.3 billion gallons/year, with the lower end of the range corresponding to "The Zero Carbon Energy scenario," and the higher end of the range corresponding to "The High CDR scenario." The range represents roughly 9% to 18% of statewide annual petroleum transportation fuels use from 2013-2017, indicating the planned reduction in liquid hydrocarbon combustion fuels reliance by 2045.[181] Liquid biofuels account for approximately 1.4 to 1.8 billion gallons/year by 2045, which is roughly 40% to 100% of liquid transportation fuels use in 2045 depending on scenario, with 100% corresponding to "The Zero Carbon Energy Scenario." So, in "The Zero Carbon Energy Scenario," the most ambitious of the three, though biofuels constitute the entirety of liquid transportation fuel use, liquid transportation fuel use overall is greatly reduced.

These State-commissioned studies put limits on the use of biofuels by specifically excluding or limiting the production of HEFA ("lipid") fuels. PATHWAYS, the primary

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[179] Mahone et al., 2020. Achieving Carbon Neutrality in California: Pathways Scenarios Developed for the California Air Resources Board, California Air Resources Board, Energy and Environmental Economics, Inc. https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_report_oct2020_0.pdf .
[180] Mahone et al., 2020.
[181] Mahone et al., 2020.

modeling tool for the AB 32 Scoping Plan, now run a biofuels module to determine a least-cost portfolio of the biofuel products ultimately produced (e.g. liquid biofuel, biomethane, etc.) based on biomass availability.[182] Mahone et al. chose to exclude purpose-grown crops, as explained in prior similar studies, because of its harmful environmental impacts and climate risks and further limitied the biomass used to in-state production in addition to California's population-weighted share of total national waste biomass supply.[183] Consequently, it was assumed that all California biofuel feedstock should be cellulosic residues as opposed to the typical vegetable oil and animal fat HEFA feedstocks. A study by Austin et al. meanwhile, in considering pathways to reduce California's transportation emissions, placed a cap on HEFA jet fuel and diesel use to a maximum of 0.5–0.6 and 0.8–0.9 billion gallons/year, respectively.[184] Yet new in-state HEFA distillate (diesel and jet fuel) production proposed statewide, with a large share to come from the Martinez Refinery, would total approximately 2.1 billion gallons/year when fully operational.[185] If fully implemented, HEFA fuel production could exceed caps of 0.0–1.5 billion gallons/year prescribed by the aforementioned state climate pathways.

In both studies, the reason given for limiting HEFA fuel reliance is the difficult-to-predict land use emissions associated with HEFA feedstocks. As discussed in the previous subsection, HEFA fuels can be associated with significant greenhouse gas emissions, on par with emissions from conventional oil production in some cases. Additionally, the refining emissions associated with HEFA production, impact HEFA fuel cycle emissions—an impact that the DEIR did not consider. The carbon intensity of HEFA refining is roughly 180% to 240% of the carbon

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[182] E3 introduced a new biofuels module in the model that, unlike previous iterations of the PATHWAYS model, endogenously selects least-cost biofuel portfolios given the assumed available biomass. Mahone et al., 2020, footnote 2 at 19-20.

[183] *See e.g.,* Mahone et al., 2018. *Deep Decarbonization in a High Renewables Future: Updated results from the California PATHWAYS Model;* Report CEC-500-2018-012. Contract No. EPC-14-069. Prepared for California Energy Commission. Final Project Report. Energy and Environmental Economics, Inc.: San Francisco, CA. https://ww2.energy.ca.gov/2018publications/CEC-500-2018-012/CEC-500-2018-012.pdf ("most scenarios apply this more restrictive biomass screen to avoid the risk that the cultivation of biomass for biofuels could result in increased GHG emissions from natural or working lands.", pp. 10)

[184] Austin et al., 2021. *Driving California's Transportation Emissions to Zero;* Report No.: UC-ITS-2020-65. Institute of Transportation Studies, University of California. DOI: 10.7922/G2MC8X9X. https://escholarship.org/uc/item/3np3p2t0

[185] Supporting Material Appendix for *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, www.energy-re-source.com; *Application for Authority to Construct Permit and Title V Operating Permit Revision for Rodeo Renewed Project: Phillips 66 Company San Francisco Refinery (District Plant No. 21359 and Title V Facility # A0016);* Prepared for Phillips 66 by Ramboll US Consulting, San Francisco, CA. May 2021; *Initial Study for: Tesoro Refining & Marketing Company LLC—Marathon Martinez Refinery Renewable Fuels Project;* received by Contra Costa County Dept. of Conservation and Development 1 Oct 2020; *April 28, 2020 Flare Event Causal Analysis; Tesoro Refining and Marketing Company, subsidiary of Marathon Petroleum, Martinez Refinery Plant #B2758;* report dated 29 June, 2020 submitted by Marathon to the Bay Area Air Quality Management District: San Francisco, CA. https://www.baaqmd.gov/about-air-quality/research-and-data/flare-data/flare-causal-reports; *Paramount Petroleum, AltAir Renewable Fuels Project Initial Study;* submitted to City of Paramount Planning Division, 16400 Colorado Ave., Paramount, CA. Prepared by MRS Environmental, 1306 Santa Barbara St., Santa Barbara, CA; Brelsford, R. Global Clean Energy lets contract for Bakersfield refinery conversion project. *Oil & Gas Journal*. 2020**.** Jan. 9, 2020.

intensity of refining at the average U.S. crude refinery.[186] Those refining emission increments would then add to the potentially larger effect of overuse of biofuels instead of ZEVs.

Repurposing refineries for HEFA biofuels production using steam reforming would thus increase the carbon intensity of hydrocarbon fuels processing when climate goals demand that carbon intensities decrease. . That could contribute significantly to emissions in excess of the needed climate protection and state policy trajectory. California's goal of 2050 goal of emissions 80% below 1990 levels by 2050[187] is equivalent to 86.2 million tons (MT) CO_2eq emissions in 2050. Given future projections of transportation fuel demand, HEFA diesel and jet fuel CO_2eq emissions could reach 66.9 Mt per year in 2050.[188] Adding in emissions from remaining petroleum fuel production could push emissions to 91 Mt in 2050.[189] Total 2050 emissions would thus be larger than the state target.

Similarly, the goal of carbon neutrality by 2045 either requires no emissions in 2045, or for emissions that do occur to be offset by negative emissions technologies such as carbon capture and storage (CCS). Relying on HEFA fuels in the future means that there will be emissions, so without CCS, carbon neutrality will not be reached. Yet carbon capture and storage has not been proven at scale, so it cannot be relied upon to offset HEFA fuel-associated emissions to meet mid-century emissions goals. Existing CCS facilities capture less than 1 percent of global carbon emissions, while CCS pilot projects have repeatedly overpromised and underdelivered in providing meaningful emissions reductions.[190] Therefore, repurposing idled petroleum refinery assets for HEFA biofuels will cause us to miss key state climate benchmarks.

The DEIR's conclusion that the Project is consistent with state climate directives without the analysis described above is a fatal flaw in that conclusion. A recirculated DEIR must evaluate all of the pathway studies and analysis described in this section, and make a determination regarding the Project's consistency with the state's climate law and policy based on all of the factors described in this comment.

C. The DEIR Failed to Consider a Significant Potential GHG Emission Shifting Impact Likely to Result from the Project

Despite claims that biofuels have a carbon benefit, the data thus far show that increased biofuel production has actually had the effect of *increasing* total GHG emissions, by simply pushing them overseas. Instead of replacing fossil fuels, adding renewable diesel to the liquid combustion fuel chain in California resulted in refiners increasing exports of petroleum distillates

[186] The difference between the upper and lower bounds of that range is driven by the (here undisclosed in the DEIR) difference between choices by the refinery to be made by Marathon: among HEFA feeds, and between diesel versus jet fuel production targets. Karras, 2021a.
[187] The 80% is required as a direct emission reduction, not a net reduction that may take into consideration negative emission measures such as CCS. Executive Order S-3-05.
[188] Karras, 2021a. For context, HEFA hydrogen steam reforming emissions alone could account for some 20 Mt/yr or more of this projected 66.9 Mt/yr.
[189] *Id.*
[190] Center for International Environmental Law, Confronting the Myth of Carbon-Free Fossil Fuels, Why Carbon Capture Is Not a Climate Solution (2021), https://www.ciel.org/wp-content/uploads/2021/07/Confronting-the-Myth-of-Carbon-Free-Fossil-Fuels.pdf.

burned elsewhere, causing a worldwide net increase in GHG emissions. The DEIR improperly concludes the project would decrease net GHG emissions[191] without disclosing this emission-shifting (leakage) effect. A series of errors and omissions in the DEIR further obscures causal factors in the emission shifting by which the project would cause and contribute to this significant potential impact.

1. <u>The DEIR Fails to disclose or Evaluate Available Data That Contradict Its Conclusion That the Project Would Result in a Net Decrease in GHG Emissions</u>.

State climate 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."[192] However, the DEIR fails to 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[193] and total distillates—petroleum distillates and diesel biofuels—burned in California.[194] Had the DEIR evaluated these data the County could have found that its conclusion regarding net GHG emissions resulting from the project was wholly unsupported.

As shown in Chart 2, petroleum distillate fuels refining for export continued to expand in California in the last two decades even as biofuel production ramped up in recent years. It is clear from this data that renewable diesel production since 2012 - originally expected to replace fossil fuels - actually merely added a new source of carbon to the global liquid combustion fuel chain. Total distillate volumes, including diesel biofuels burned in-state, 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.[195] [196]

Specifically, crude 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, in fact, 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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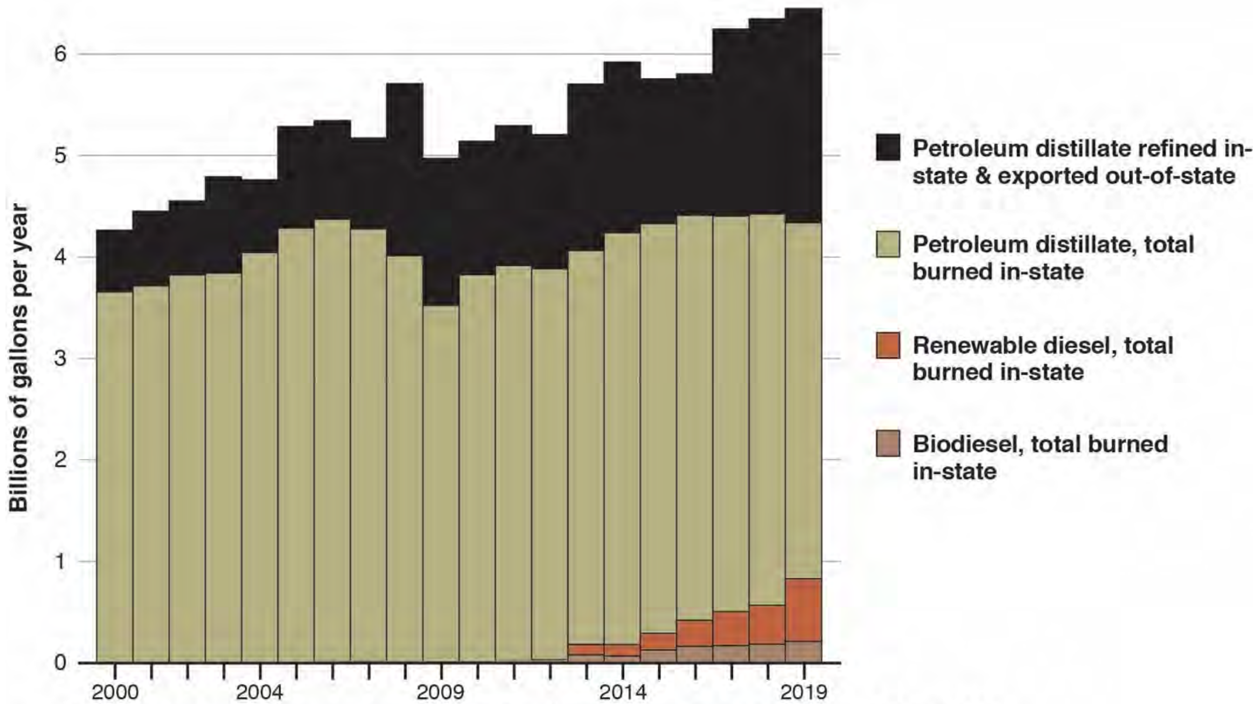
[191] "Project would result in an overall decrease in emissions ... [including] indirect GHG emissions" (DEIR p. 3.8-20) and "GHG emissions from stationary and mobile sources" DEIR at 3.8-22.
[192] CCR §§ 38505 (j), 38562 (b) (8).
[193] CEC Fuel Watch data, various dates.
[194] CARB GHG Inventory Fuel Activity data, 2019 update.
[195] *Id.*
[196] CEC *Fuel Watch*. Weekly Refinery Production. California Energy Commission: Sacramento, CA. https://ww2.energy.ca.gov/almanac/petroleum_data/fuels_watch/output.php



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 and CARB GHG Inventory Fuel Activity Data, 2019 update.

2. <u>The DEIR Fails to Consider Exports in Evaluating the Project's Climate Impact</u>

The DEIR describes potential GHG emissions resulting from imports[197] while ignoring fuels exports from California refineries and conditions under which these exports occur – a key factor in assessing the Project's global climate impact, as discussed in the previous subsection. 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.[198] Importantly, before diesel biofuel addition further increased refining of petroleum distillates for export, the structural over-capacity of California refining infrastructure was evident from the increase in their exports after in-state demand peaked in 2006. *See* Chart 2. California refining capacity, especially, is overbuilt.[199] Industry reactions -- seeking to protect those otherwise stranded refining assets through increased refined fuels exports as domestic markets for petroleum fuels declined -- resulted in California refiners exporting fully 20% to 33% of

[197] DEIR p. 4-12
[198] USEAI, 2015.
[199] Karras, 2020. *Decommissioning California Refineries.*

statewide refinery production to other states and nations from 2013–2017.[200] West Coast data further demonstrate the strong effect of changes in domestic demand on foreign exports from this over-built refining center.[201] *See* Table 7.

Table 7. 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, West Coast (PADD 5) *Supply and Disposition*; www.eia.gov/dnav/pet/pet_sum_snd_d_r50_mbbl_m_cur.htm

Current California and West Coast data 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 related Contra Costa County crude-to-biofuel conversion project. Accordingly, the project can be expected to worsen in-state petroleum refining overcapacity, and thus the emission shift, by adding a very large volume of renewable diesel to the California liquid combustion fuels mix.

Despite the project objective to provide renewable fuels to the California market, which could further shift petroleum fuels from this market, the DEIR fails to disclose or evaluate this causal factor in the observed emission shifting impact of recent renewable fuel additions.

3. <u>The DEIR Fails to Describe or Evaluate Project Design Specifications That Would Cause and Contribute to Significant Emission-Shifting Impacts</u>

By failing to disclose and consider refinery export patterns, the DEIR fails to address the essential question of how fully integrating renewable diesel into petroleum fuels refining, distribution, and combustion infrastructure could worsen GHG emission shifting by more directly tethering biofuel addition here to petroleum fuel refining for export. Compounding its error, the DEIR fails to evaluate the degree to which the Project's HEFA diesel production capacity could add to the existing statewide distillates production oversupply, and 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. *See* Table 8.

[200] *Id.*
[201] USEIA, West Coast (PADD 5) *Supply and Disposition;* www.eia.gov/dnav/pet/pet_sum_snd_d_r50_mbbl_m_cur.htm

Table 8. 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. . Pearlson, M., Wollersheim, C., and Hileman, J., A techno-economic review of hydroprocessed renewable esters and fatty acids for jet fuel production, Biofuels, Bioprod. Bioref. 7:89-96 (2013). DOI: 10.1002/bbb.1378. **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 Rodeo project calculated at 55,000 b/d feed rate, less than the 80,000 b/d Rodeo project capacity.

Accounting for fuel yields on refining targeting renewable diesel[202] and typical feed and fuel densities shown noted in Table 8, at its 48,000 b/d capacity the project could produce approximately 1.62 million gallons per day of renewable diesel, potentially resulting in crude refining for export of the equivalent petroleum distillates volume if current patterns continue. State default emission factors for full fuel chain "life cycle" emissions associated with the type of renewable diesel proposed[203] account for a range of potential emissions from lower ("residue") to higher ("crop biomass") emission feeds, also shown in the table. The net emission shifting impact of the project based on this range of state emission factors could thus be approximately 3.46 to 4.99 million metric tons (Mt) of CO_2e emitted per year. Table 8. 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*.

[202] Pearlson et al., 2013.
[203] Low Carbon Fuel Standard Regulation, CCR §§ 95484–95488, tables 2, 4, 7-1, 8 and 9.

VII. THE DEIR FAILS TO ADEQUATELY DISCLOSE AND ANALYZE THE PROJECT'S AIR QUALITY IMPACTS

As discussed in Section III above, the DEIR is fatally flawed for having chosen a baseline that assumes an operating crude oil refinery rather than actual current conditions, in which the refinery is shut down with no plan or intention to continue processing crude oil. That flaw renders the entire analysis of air emissions in the DEIR inadequate, because the conclusion that "[t]he Project would result in emission reductions of all criteria air pollutants from both stationary and mobile sources" (DEIR at 3.3-38) is based on a faulty premise and must be revisited; as must all air quality health impacts analysis and cumulative impacts analysis that is grounded in this conclusion. Starting from a zero baseline, the analysis should determine the increase in pollutants associated with operating the Project over current shutdown conditions. Since the calculations in the DEIR indicate that such emissions will be significant and unavoidable using the BAAQMD thresholds of significance, and the DEIR should further identify mitigation measures to address those emissions.

Even aside from the faulty baseline, however, the DEIR analysis of air quality impacts suffers from three major flaws described in the subsections below- the first of which was addressed extensively in the Scoping Comments but ignored by the County. First, for reasons discussed in Section VI concerning GHG emissions, the analysis fails to take into account the widely differing air emissions impact associated with both different feedstocks and different product slates. Those differences should have been factored in the reasonable worst case scenario analysis to address uncertainty as to the feedstocks that will be used, *see* Sections II and IV, as well as any other feedstock scenarios appropriate to the analysis. Second, the DEIR air quality analysis systematically excludes acute exposures to short-term episodic facility emissions in nearby communities from consideration, even though the Project risks increasing acute exposures associated with flaring. And third, the DEIR odor analysis of new malodorous feedstock in new and repurposed facilities adjacent to vulnerable populations is too cursory and incomplete to approach sufficiency.

A. The DEIR Air Impacts Analysis Fails to Take Into Account Varying Air Emissions from Different Feedstocks and Crude Slates

Section VI demonstrates that GHG emissions vary significantly with differing feedstocks and product slates. For these same reasons and others, emissions of multiple air pollutants vary with feedstock and product slate as well. Processing a different type of oil – including crude feedstock oils – can increase processing emissions in several ways. It can introduce contaminants that escape the new feed and pass through the refinery into the local environment. It can require more severe, more energy-intensive processing that burns more fuel per barrel, increasing combustion emissions from the refinery. At the same time, processing the new feed can change the chemistry of processing to create new pollutants as byproducts or create polluting byproducts in greater amounts.

There are also potential increases in emissions of air pollutant emissions – including nitrogen oxides, particulate matter, sulfur dioxide, and polycyclic aromatic hydrocarbons, among others – associated with fossil fuel combustion and energy demand in proposed Project processes. The emissions result not only from the more intense hydrogen demands associated with certain feedstocks (*see* Section VI), but from the higher energy demands in addition to hydrogen reforming associated with processing certain types of feedstocks. More contaminated or difficult to pretreat feeds may require more energy in the proposed new feed pretreatment plant. Feeds that are more difficult to process may require more recycling in the same hydrotreater or hydrocracker, such that processing each barrel of fresh feed twice, for example, may double the load on pumps, compressors, and fractionators at that process unit, increasing the energy needed for processing. As another example further downstream in the Refinery, feeds that yield more difficult to treat combinations of acids and sour water as processing byproducts may need additional energy for pretreatment to prevent upsets in the main wastewater treatment system. Feeds that require more energy-intensive processing of this nature may increase combustion emissions of an array of toxic and smog-forming pollutants, including but not limited to those noted above.

Additionally, contaminants in the feedstocks themselves can be released during processing, adding to the air emissions burden. Fish oils can be contaminated with bio-accumulative lipophilic toxins such as polychlorinated biphenyls, dioxins, and polybrominated diphenyl ethers, which could be released from processing at 48,000 barrels per day in cumulatively significant amounts. So-called "brown grease" collected from sewage treatment plants – another potential feedstock whose use has not been ruled out - can adsorb and concentrate lipophilic toxic chemicals from across the industrial, commercial and residential sewerage collection systems—disposal and chemical fate mechanisms similar to those that have made such greases notoriously malodorous.

B. The DEIR Fails to Assess the Likelihood of Increased Air Pollution Associated With the Increased Likelihood of Process Upsets[204]

As discussed in Section V, running biofuel feedstocks risks increasing the likelihood of process upsets and flaring incidents at the Refinery. Any such incident will result release of in a significant volume of uncontrolled air emissions. Accordingly, the DEIR should have addressed those emissions, and ways to mitigate them,as part of its air quality impacts analysis. Specifically, the DEIR should have determined whether increased flaring is likely as a result of HEFA processes (per Section V); described the air impacts associated with flaring (which are acute rather than chronic); and evaluated the possibility of limits on certain feedstocks prone to cause flaring as a mitigation measure.

1. <u>The DEIR Did Not Describe the Air Quality Impacts of Flaring</u>

Although the inclusion of repurposed refinery flare systems in the project clearly anticipates their use, and serious local air impacts have long been known to occur as a result of refinery flares, the DEIR simply does not describe those impacts. This is a fatal flaw in the DEIR independently from its flawed baseline analysissince, as discussed in Section V, the Project is likely to increase process upset incidents at the Refinery.

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[204] Supplemental information in support of this analysis is provided in Karras 2021c accompanying this comment, in the section entitled "Air Quality and Hazard Release Impacts of Project Flaring that Available Evidence Indicates Would be Significant are Not Identified, Evaluated, or Mitigated in ihe DEIR."

The County cannot argue that data for this essential impact description were not available. As described in a recent technical report:

> Causal analysis reports for significant flaring show that hydrogen-related hazard incidents occurred at the Phillips 66 Rodeo and Marathon Martinez refineries a combined total of 100 times from January 2010 through December 2020 ... on average, and accounting for the Marathon plant closure since April 2020, another hydrogen-related incident at one of those refineries every 39 days.
>
> ... Sudden unplanned or emergency shutdowns of major hydro-conversion of hydrogen production plants occurred in 84 of these 100 reported safety hazard incidents. Such sudden forced shutdowns of *both* hydro-conversion and hydrogen production plants occurred in22 of these incidents. ... In four of these incidents, consequences of underlying hazards included fires in the refinery.
>
> ... Refinery flares are episodic air polluters. Every time the depressurization-to-flare safeguard dumps process gases in attempts to avoid even worse consequences, that flaring is uncontrolled open-air combustion. Flaring emits a mix of 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 incidents described above flared more than two million cubic feet of vent gas each, and many flared more than ten million.
>
> ... In 2005, flaring was linked to episodically elevated local air pollution by analyses of a continuous, flare activity-paired, four-year series of hourly measurements of the ambient air near the fence lines of four Bay Area refineries. By 2006, the regional air quality management district independently confirmed the link, assessed community-level impacts, and set environmental significance thresholds for refinery flares. These same significance thresholds were used to require [Phillips 66 and Marathon and previous owners of the Rodeo and Martinez refineries] to report the hazard data described above.
>
> ... Thus, each of the hundred hydrogen-related flaring incidents since 2010 at the P66 Rodeo and MPC Martinez refineries discussed above *individually* exceeded a relevant environmental significance threshold for air quality. [205]

2. <u>The DEIR Failed to Describe the Impact of Feedstock Switching on Flaring</u>

With regard to causal factors for flaring, the allusion in the DEIR to reduced process hazards because the Project would result in fewer onsite equipment units where incidents could occur is specious. The hundred incidents described above include only those in which the type of process units to be repurposed for the Project *and* hydrogen-related hazards were causal factors in an environmentally significant flaring incident.[206] Had the DEIR evaluated the same

[205] Karras, 2021a.
[206] Karras, 2021a.

data source,[207] [208] the County could have found that the same refining processes that would be repurposed for the project dominate the historic refinery flaring pattern.

All of the uniquely pronounced inherent process hazards resulting from converting crude refineries to HEFA refineries—which is what the Project proposes—result in *designing* HEFA conversions to dump process gas to flares when such hazards arise. The increased exothermic runaway reaction hazard due to more hydrogen-intensive processing of HEFA refining than crude refining, and associated need for upgraded capacity for rapid depressurization to flares, are noted industry-wide.[209] [210] Failure to evaluate this potential for Project HEFA refining to increase the frequency of refinery flaring compared with historic crude refining at the site is a major deficiency in the DEIR flaring analysis. Had the DEIR performed this essential evaluation, the County could have found that:

> [D]espite current safeguards, hydro-conversion and hydrogen-related process safety hazards which their HEFA conversion projects could worsen contribute to significant flaring incidents at the P66 Rodeo and MPC Martinez refineries frequently. ... [S]witching to HEFA refining is likely to further increase the frequency and magnitude of these already-frequent significant process hazard incidents ...
>
> ... The increased risk of process upsets associated with HEFA processing concomitantly creates increased risk to the community of acute exposures to air pollutants ... Therefore, by prolonging the time over which the frequent incidents continue, and likely increasing the frequency of this significant flaring, repurposing refineries for HEFA processing can be expected to cause significant episodic air pollution."[211]

3. <u>The DEIR Fails to Evaluate the Likelihood of Increased Flaring</u>

Refinery flare incidents can be prevented by the same measures that can prevent the catastrophic explosion and fire incidents which flares are designed to (partially) mitigate; removing the underlying causes of those hazards. From and an environmental health and safety perspective, this is the crucial fact about flaring. In this regard, its incomplete and misleading allusion to flaring as merely a way to make refining safer, which incidentally emits some pollutants, obscures a third fatal flaw in the DEIR flaring analysis: it failed to address the elective processing of feedstock types that would cause preventable flaring.

Refinery flares are designed and permitted for use only in emergencies, the only exception being limited to when unsafe conditions are both foreseeable *and* unavoidable.[212] Here in the Bay Area, preventable refinery flaring is an unpermitted activity that contravenes air

[207] BAAQMD Regulation 12-12-406 Causal Reports; reports relevant to the Project accompany this Comment; recent reports available at https://www.baaqmd.gov/about-air-quality/research-and-data/flare-data/flare-causal-reports
[208] BAAQMD Regulation 12 Rule 12. Bay Area Air Quality Management District Regulation 12, Miscellaneous Standards of Performance, Rule 12. BAAQMD: San Francisco, CA. Amended 3 November 2021.
[209] van Dyk et al., 2019.
[210] Chan, 2020.
[211] Karras, 2021a.
[212] The limited exception does not apply where, as here, known measures to avoid flaring can be taken before unsafe conditions that result in flaring become locked into place, e.g., the inherently safer processing systems and designs are identified and can be implemented during construction or implementation.

quality policy and law.[213] The DEIR fails to address this fact. The DEIR declines to expressly define or limit the feedstocks that will be used, without addressing the issue that electing to process some of those feeds rather than others could result in more frequent environmentally significant flaring impacts, contrary to air quality policy and law.

Had the DEIR addressed this issue, the County could have found that:

- A portion of the range of potential HEFA feedstocks, including soybean oil, distillers corn oil and most other crop oils, have relatively higher process hydrogen requirements than other potential feedstocks for Project biofuel refining;[214]
- Electing to process feedstocks in that high process hydrogen demand category would release more heat during processing, thereby increasing the frequency of process temperature rise hazard incidents and hence environmentally significant flaring;[215] and
- The resultant more frequent flaring from electing a feedstock which unnecessarily intensified underlying flaring would be preventable since another feedstock would reduce flaring frequency in accordance with air quality policy and law, and consequently, the proposed Project flaring could result in significant impacts.

C. The DEIR Fails to Address Acute Episodic Air Pollution Exposures

Although as described in the previous subsection flaring causes acute episodic air pollution exposure and will increase in frequency with the Project, the DEIR systematically excludes acute exposures to short-term episodic facility emissions from consideration. Overwhelming evidence based on scientific data, information, and the long history of environmental, toxicological, and environmental justice experience and practice demonstrate the necessity to address acute as well as chronic and local as well as regional exposures to air pollutants. For example, the facility air permit itself specifies hourly and daily as well as annual emission limits.[216] Yet throughout the DEIR it erroneously conflates these acute and chronic exposure impacts, drawing numerous conclusions that facility emission impacts of the Project are "beneficial" or "less than significant" based on average rates of emission from continuous sources alone.

Potential air quality impacts associated with acute exposures to short-term episodic emissions from the refining facilities are systematically excluded from DEIR consideration.[217] The DEIR fails to evaluate or address episodic emissions from flaring, as discussed directly above in subsection B. The DEIR Health Risk Analysis (HRA) is based solely on average long-term exposure data. Additionally, the DEIR calculations and estimates fail to account for combined effects of site-specific source, geographic, demographic, and climatic factors that worsen episodic air pollutant exposures locally. The DEIR further relies upon incomplete local

[213] BAAQMD Regulation 12, Rule 12.
[214] Karras, 2021a.
[215] Karras, 2021a.
[216] Major Facility Review Permit Issued To: Tesoro Refining & Marketing Company LLC, Facility #B2758 & Facility #B2759; Jan. 11, 2016.
[217] Karras, 2021c

air monitoring, which could not and did not measure incident plumes. Local air monitoring also excludes from measurement many air pollutants associated with upsets and flaring. The DEIR's error of conflating impacts of acute and chronic air pollutant exposures obscures its failure to consider acute exposure to short-term episodic emissions. In most cases, its comparisons underlying those conclusions appear to be grounded in no acute exposure or episodic emission data at all.[218]

Additionally, the DEIR failed to consider potential means of mitigating the impact of flaring associated with HEFA processes by limiting uses of the feedstocks most prone to causing excess flaring. As discussed in Section VI, a portion of the range of potential HEFA feedstocks, including soybean oil, distillers corn oil and most other crop oils, have relatively higher process hydrogen requirements than other potential feedstocks for Project biofuel refining;[219]Processing feedstocks with higher hydrogen demand releases more heat during processing, thereby increasing the frequency of process temperature rise hazard incidents -- and hence environmentally significant flaring.[220] The DEIR should therefore have considered the possibility of capping or prohibiting the use of feedstocks with higher risk of causing flaring incidents.

The DEIR must therefore be revised to include an disclosure and assessment of the likelihood of increased flaring associated with the proposed HEFA process, including reasonable worst case scenario analysis taking into account variation in flaring associated with different feedstocks. It must then calculate the increased acute air pollution associated with such flaring, and identify potential mitigation measures to diminish the likelihood of flaring associated with the HEFA process, including feedstock limitations.

D. The DEIR fails to Adequately Address Potential Odors from the Project

The DEIR concludes that the Project would result in a significant odor impact despite the engineered measures, but concludes that odor impacts could be reduced to less than significant through use of an "Odor Management Plan" -- to be developed, implemented, maintained, monitored and updated as necessary *after* Project approval. DEIR at 3.3-41. The DEIR does not discuss the effectiveness or pitfalls observed from prior or existing use of odor management plans at the Refinery.

The DEIR's reliance on a not-yet-developed odor management plan is misplaced. In the first instance, such a plan runs afoul of the CEQA requirement that "Formulation of mitigation measures shall not be deferred until some future time." CEQA Guidelines § 15126.4(a)(1)(B); and that "Mitigation measures must be fully enforceable through permit conditions, agreements, or other legally-binding instruments." *Id.* at § 15126.4(a)(2).

Additionally, as a substantive matter, the DEIR does not adequately describe how the proposed mitigation would be effectively at reducing impacts to non-significance – specifically, how odors would be eliminated in the context of an open-plan petroleum refinery surrounded by

218 Karras, 2021c.
219 Karras, 2021a.
220 Karras, 2021a.

densely packed communities. Moreover, any proposed mitigation – and description of its effectiveness – must account for the fact that the DEIR does not preclude use of any type of feedstock – meaning that a reasonable worst case scenario analysis must account for the possibility that highly odorous feedstocks will be used. These could, in principle, include "FOG" (fats, oils and grease) – a category of feedstock includes a particular type of "brown grease."Brown grease is a highly malodorous oil and grease extracted from the grease traps, "mixed liquor" (microbial cultures with their decomposition products) and "biosolids" (sewage sludge) in publicly owned treatment works, commonly known as sewage plants, originating in the broad mix of residential, commercial and industrial waste water connections to sewage plants across urban and suburban landscapes.

The DEIR further fails to provide a sufficiently detailed description and analysis of the infrastructure from which the odors may be emitted – including the transport system, the storage system, and the pre-processing system – including design specifications, potential points of atmospheric contact, and the proximity to adjacent populations. Such analysis is crucial to supporting the DEIR conclusions that an odor management plan will reduce the impact to less than significant.

VIII. THE DEIR'S ASSESSMENT OF ALTERNATIVES TO THE PROJECT IS INADEQUATE

Analysis of project alternatives, together with identification of mitigation, form the "core of the EIR." *Jones v, Regents of University of California* (2010), 183 Cal.App.4th 818, 824-25. That core is deeply flawed here. First, the document fails to consider a "no project" alternative that realistically represents conditions without the Project, since those conditions do not include an operating refinery. Second, the alternatives analysis artificially conflates numerous alternatives that can and should have been considered collectively as a means to reduce Project impacts. Third, while the analysis appropriately includes an electrolytic hydrogen alternative, the analysis of that alternative omits important criteria that should have been considered.

A. The DEIR Does Not Evaluate A Legally Sufficient No-Project Alternative

In examining a range of alternatives, an EIR is required to include a "no project" alternative to facilitate assessment of the impact of the remaining alternatives. "The purpose of describing and analyzing a no project alternative is to allow decisionmakers to compare the impacts of approving the proposed project with the impacts of not approving the proposed project. ..." CEQA Guidelines § 15126.6(e)(1). "The 'no project' analysis shall discuss the existing conditions ... as well as what would be reasonably expected to occur in the foreseeable future if the project were not approved, based on current plans and consistent with available infrastructure and community services. ..." CEQA Guidelines, § 15126.6, subd. (e)(2). It is essential that the "no project" alternative accurately reflect the status quo absent the project, to ensure that the baseline for measuring project impacts is not set too high, which would artificially diminish the magnitude of Project impacts. *See Ctr. for Biological Diversity v. Dep't of Fish & Wildlife* (2014), 234 Cal.App.4th 214, 253 (citation omitted) (emphasis in original) ("a no project alternative in an EIR 'provides the decision makers and the public with specific information about the environment if the project is not approved. It is a factually based forecast of the environmental impacts of *preserving the status quo*. It thus provides the decision makers with a base line against which they can measure the environmental advantages and disadvantages of the project and alternatives to the project.'").

For reasons explained in Section II, concerning the Project baseline, the DEIR incorrectly identified the no project alternative as the scenario where crude oil operations would resume, continuing crude oil processing operations indefinitely at historic levels. DEIR at 5-4. Yet the document provides no evidence whatsoever to support this conclusion. It is an unsubstantiated assumption contradicted by mountains of evidence – much of it provided in the Scoping Comments and even more provided in these Comments – that Marathon has no plans to restart crude oil processing at the Refinery if its application to convert to biofuel production is denied. It is imperative, to ensure a rational alternatives analysis, that the County include a no project alternative that is grounded in reality.

A no project alternative reflecting the reality of the Refinery's closure would have found multiple significant impacts where the DEIR currently finds no significant impact or, in some cases, reduced impact. Additionally, a no project alternative reflecting that reality would need to address the need to decommission the refinery and address any hazardous waste issues, as discussed in Section X. The DEIR needs to confront the reality that if the Project is not approved, a massive – and environmentally impactful – cleanup effort will be required to address the decades of hazardous contamination fouling the idled site.

B. The DEIR Alternatives Analysis Artificially Separates Alternatives that are Not Mutually Exclusive

In addition to the (inappropriately characterized) no project alternative, the DEIR considered two additional alternatives in addition to the Project: the "reduced renewable feedstock throughput" alternative and the "green hydrogen" alternative. DEIR at 5-4 – 5. These alternatives were appropriate for consideration, as both are feasible means to reduce Project impacts. However, the DEIR presents no reason why these two alternatives were evaluated as separate options rather than collectively. Nothing about them is mutually exclusive: electrolytic "green" hydrogen could supply a refinery with reduced throughput in the same way it could supply the Project. Nothing in the DEIR suggests to the contrary. Indeed, to the extent the scale of required electrolytic hydrogen may be a concern – e.g., with respect to the reference in the DEIR concerning the Refinery's footprint with the addition of solar panels – implementing the two alternatives together would mitigate that concern. The DEIR should therefore have either considered the two non-project alternatives collectively in addition to separately, or else provided sufficient evidence and reasoning as to why this combined approach would not be feasible.

C. The Analysis of the Green Hydrogen Alternative Fails to Consider Essential Information Concerning its Benefits

Commentors raised in the Scoping Comments the need for reasonable analysis of renewable powered electrolytic zero emission hydrogen (ZEH) . The DEIR acknowledges that ZEH is feasible.

However, the DEIR did not present a reasonable analysis ZEH. Its analysis was unreasonbly biased by a combination of overly narrow interpretation of Project objectives, incomplete description of ZEH, and failure to consider significant impacts ZEH could lessen or avoid. The DEIR states that alternatives were considered based on three criteria (in addition to the no project alternative requirement): achievement of Project goals, lessening of impacts, and feasibility. While these criteria were not inappropriate, the analysis was skewed and deficient in several ways, all potentially to the detriment of fair consideration of the green hydrogen alternative. Indeed, it is clear from information the County has provided to Commenters that its site-specific analysis of the feasibility of the green hydrogen alternative was exceedingly limited.[221]

These flaws are significant. The Project's fossil gas "gray" hydrogen production that ZEH could replace will emit roughly one million metric tons of carbon dioxide annually. Failing to consider elimating that million annual tons as mitigation for significant Project GHG impacts is not a reasonable DEIR analysis.

1. Overly Narrow Interpretation of Project Objectives

First, the Project objectives are drawn in an overly narrow fashion that may unfairly bias consideration of the green hydrogen alternative (as well as alternative technologies more generally, per Section II). The list of Project objectives in the DEIR twice references a goal of "repurposing" Refinery infrastructure. DEIR at 1-1. However, framing the Objectives in this manner by nature weighs against any alternatives – such as the green hydrogen alternative – that would upgrade and replace heavily polluting refinery infrastructure while still allowing biofuel production to proceed. The fundamental goal of the Project is to manufacture biofuels; "repurposing" is merely a strategy by which Marathon seeks to hold costs down. Why the company may for that reason consider repurposing economically advantageous, allowing every strategy to economize to rise to the level of a fundamental Project objective would bias the CEQA process in favor of the cheapest and most polluting alternatives, and against alternatives that are costlier but more environmentally sound. Defining project objectives in such an "artificially narrow" fashion violates CEQA. *North Coast Rivers Alliance v. Kawamura* (2015), 243 Cal.App.4th 647, 654. [222]

2. The DEIR's Incomplete description of ZEH Skewed DEIR Environmental Analysis

The DEIR concludes without sufficient basis that ZEH would result in certain impacts to a greater extent than the Project or other alternatives due to an increased onsite solar generation footprint. However this unsupported impact conclusion assumed onsite solar power would be the only source electricity for splitting water to create zero emission hydrogen, This impact conclusion relied on the size of the onsite solar footprint. But that was false reliance. Despite abundant well documented evidence that grid-supported as well as onsite power is a standard

[221] Commenter NRDC submitted a Public Records Act request to the County for "Records concerning electrolysis or "green" hydrogen at the Marathon/Tesoro Martinez refinery in connection with the DEIR for the Renewable Fuels Project, County File No. CDKP20-02046, SCH No. 2021020289." Letter dated November 9, 2021 from Ann Alexander to Lauwrence Huang. In response, via the email from Lawrence Huang to Ann Alexander also dated November 9, 2021, the County provided only a single one-paragraph document from Marathon concerning the site-specific aspects of an electrolytic hydrogen alternative.
[222] Moreover, if ZEH were used, the hydrogen contained in project-produced "renewable" fuels would be renewable, such that that ZEH would better achieve the renewable fuels production project objective.e.*See* Karras, 2021a. *Changing Hydrocarbons Midstream*

option for ZEH* neither grid-only nor grid-plus-onsite power was disclosed or evaluated in the DEIR, further skewing its analysis.

3. The DEIR Fails to Consider Significant Project Impacts ZEH Could Lessen or Avoid

The DEIR analysis fails to sufficiently consider the ways in which ZEH would mitigate the Project's significant climate impacts - identified in this Comment, but not the DEIR, per Sections II and VIAs discussed in those sections, while the DEIR determines the Project's GHG impacts to be non-significant, DEIR at 3.8-21, that determination was incorrect – both due to the inappropriately inflated Project baseline as described in Section II, and the DEIR's failure to account for the hydrogen intensity and emission-shifting impacts of biofuel production, as described in Section VI.

As discussed in Section VI, California's climate policy includes a commitment to zero-emission transportationConstruction of ZEH at the Project site could be critical for achieving this goal, to the extent it sets of the possibility of re-purposing the ZEH in the future for direct transportation use once the commercial life of the repurposed Refinery ends in the reasonably foreseeable future (*see* Section II). Fuel cell electric vehicles (FCEVs) can decarbonize transportation uses of energy where battery-electric vehicles (BEVs) might be more costly, such as long-haul freight and shipping, in which the size and mass of BEV batteries needed to haul large loads long distances reduce the load-hauling capacity of BEVs. In state climate pathways, renewable hydrogen use in transportation grows from an average of 1.24 million standard cubic feet per day (MMSCFD) in 2019[i] to roughly 1,020–1,080 MMSCFD by 2045.[56–58] This 2045 range reflects different scenarios for the mix of BEVs and FCEVs in different vehicle classes. The low end excludes FCEV use in LDVs[58] while the high end is a "central scenario" that includes both BEV and FCEV use in all vehicle classes.[57]

Additionally, the ability of ZEH technology to utilize peak solar and wind power and store that zero emission energy as hydrogen, enabling its return to grid at night and, perhaps more importantly, during longer calm periods of reduced wind resource power, may give ZEH a crucial role in the array of "grid balancing" measures essential to fully decarbonizing electricity.[223]

ZEH is thus critical to achieving the vehicle electrification goal, because it can fuel FCEVs without the carbon footprint of the fossil gas steam methane reforming hydrogen currently used at the Refinery, and can additionally help support the growth of renewable power for both battery and fuel cell electric vehicles growth. If ZEH has been constructed as part of the Project, that infrastructure would be poised to transition to facilitating the deployment of FCEVs contemplated by California's climate pathways. However, if the Refinery's existing hydrogen infrastructure has been repurposed for the Project and hence locked in, that infrastructure will be unable to support California's zero-carbon transportation goals.

4. The ZEH Analysis Should Have Considered Economic and Social Benefit

The DEIR does not consider the net costs (costs minus benefits) for the ZEH. In view of the very high GHG emissions and other air pollution from the legacy gray hydrogen facility, the

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[223] *See* Karras, 2021a.

mitigation is a major economic and social benefit. For this reason, the costs and benefits of the alternatives examined should have been evaluated not only in the context of project economics, but also the larger context of social costs. For example, the County can estimate the public health costs of the $PM_{2.5}$ emissions from the hydrogen operations on people living nearby.[224] Because the Refinery is situated in a densely populated urban area, the health costs from the pollution caused by the hydrogen operation are very high, and the comparable health costs from ZEH are zero.

Thus, the DEIR should have not only found the GHG impacts from the Project to be significant in view of the analysis in Sections II and VI above, but specifically taken into consideration the ability of the green hydrogen alternative to mitigate that impact.

IX. THE DEIR'S ANALYSIS OF CUMULATIVE IMPACTS WAS DEFICIENT

CEQA requires a cumulative project impacts analysis because "the full environmental impact of a proposed ... action cannot be gauged in a vacuum." *Whitman v. Board of Supervisors* (1979) 88 Cal.App.3d 397, 408. Cumulative impacts refer to two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts. Guidelines §15355. The cumulative impact from several projects is the change in the environment which results from the incremental impact of the Project when added to other closely related past, present, and reasonably foreseeable probable future projects. *Id.* The discussion of each type of cumulative impact in an EIR need only be proportional to the severity of the impact and the likelihood of its occurrence, Guidelines § 15130(b), but even an insignificant impact must be justified as such, Guidelines § §15130(a). For each cumulative impact, its geographic scope must be supported by a reasonable explanation. Guidelines § 15130(b)(3). Otherwise, an underinclusive cumulative impacts analysis "impedes meaningful public discussion and skews the decision maker's perspective concerning the environmental consequences of a project, the necessity for mitigation measures, and the appropriateness of project approval." *Citizens to Preserve the Ojai v. County of Ventura* (1985) 176 Cal.App.3d 421, 431. *See also Friends of the Eel River v. Sonoma County Water Agency* (2003) 108 Cal.App.4th 859.

The cumulative impacts analysis in the DEIR falls far short of these requirements, and fails to meet basic criteria for rationality. The DEIR largely confined its cumulative impacts analysis to projects located within 2 miles of the Project site or the associated marine oil terminals. No rationale or evidentiary support is provided for use of this particular geographic limitation; or, indeed, for selecting the evaluated projects based on a geographic limitation at all. The suite of projects swept up in this 2-mile radius are random and highly disparate, most being radically different in type from the Project and having few if any correlative impacts. These

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[224] Each 1 µg/m3 of PM2.5 that reaches 100,000 people living nearby causes 2.3 premature deaths annually. With a Value of a Statistical Life of $10,000,000 estimated by the EPA in 2019, then causing each additional 2.3 deaths leads to a social cost of $25M annually. Burnett R, Chen H, Szyszkowicz M et al. 2018; Global estimated of mortality associated with long-term exposure to outdoor fine particulate matter, PNAS 115 (38):9592-9597.

"cumulative" projects include, *inter alia,* a wetlands restoration project, a housing development, conversion of a billboard to digital format, and a self-storage unit development. DEIR at 4-3 – 7.

The very similar Phillips 66 Rodeo biofuel conversion project, lost in this strange mix, receives barely a mention in the analysis. The Rodeo project is referenced and described in a single paragraph, but "discussion" of its cumulative impacts consists of exactly two passing sentences: one referencing its purported reduction in emissions (a false conclusion, for reasons addressed in the comments being submitted by Commenters on that project's DEIR showing similar issues with a faulty baseline) (DEIR 4-8); and the other referencing, entirely non-quantitatively, the cumulative impact of the two projects on marine impacts. DEIR at 4-10.

This approach is deficient in multiple respects. First, the DEIR failed to specify a rational basis for the universe of projects considered in the cumulative impacts analysis – with respect to either the 2 mile radius or the particular array of projects evaluated within that radius. In particular, it failed to explain why projects were included in the cumulative impacts analysis whose impacts are clearly unrelated in type to the impacts of the Project. Second, the analysis is almost entirely non-quantitative, even though the Project's impacts are quantified with respect to key issues, including criteria air pollutant emissions and GHG emissions. And third, the document contains functionally zero cumulative impacts analysis of the Project as considered together with the closely related Phillips 66 Rodeo project, even though the two projects will necessarily have very similar impacts, and will cumulatively impact regional air quality, upstream agricultural land use, and the State's climate goals to a significantly greater degree than the impact of each project individually.

Rather than taking the unreasoned approach it did, the DEIR should have identified a universe of projects to include in its analysis based on information concerning those projects' impacts, and the likelihood that they will intersect with the impacts of the Project. Including a compliment of local projects in that universe would be appropriate when analyzing cumulative impacts that are local in scale; but confining the analysis entirely to local projects does not make sense with respect to project impacts that are regional (e.g., air quality impacts), statewide (impact on the state's climate policy), or national and international (climate, upstream indirect land use impacts).

Using these criteria, it is clear that, at minimum, comparable refinery biofuel conversion projects – including but not limited to the Phillips 66 project – needed to be included in the cumulative impacts analysis. The refinery feedstock market is national, and even global, in scale. Both biodiesel and renewable diesel projects in the United States compete for the same, limited supply of crop oils and animal fats. As a result, a cumulative impacts analysis should have included existing HEFA biofuel projects currently under construction and proposed in

California, such as the AltAir Paramount[225] and Alon Bakersfield[226] refinery projects as well as anticipated future conversion projects nationwide that are likely to produce similar large-scale impacts – e.g., due to anticipated use of similar feedstocks because of similar processing technology or transportation routes.

The following sections discuss particular categories of cumulative impacts that should have received scrutiny in the DEIR but did not.

A. The DEIR Should Have Analyzed the Cumulative Impact of California and Other US Biofuel Projects on Upstream Agricultural Land Use

As discussed in Section VI.D above, the Project alone has the potential to consume an enormous portion of the entire US production of the agricultural products it proposes to use as feedstocks. Project feedstock demand could boost demand for biofuel feedstock oils, currently 113,000 b/d nationwide total, by 42 percent (48,000 b/d). The Project could in principle, standing alone, consume up to 24 percent of the total U.S. supply of soybean oil production for all uses.

The larger 80,000 barrel per day Phillips 66 conversion project would have an even greater impact on feedstock consumption levels, and hence on agricultural resources and their availability. As Commenters described in separate comments concerning the DEIR for that project,[227] the Rodeo project could increase demand for feedstock oils itself by 71% and could alone consume up to 39 percent of the nation's total supply of soybean oil. Yet the overall limitation on HEFA feedstock availability is well documented within the scientific community,[228] the financial industry,[229] the environmental justice community,[230] as well as

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225 *See* Lillian, Betsy. "World Energy Acquires AltAir Renewable Fuel Assets in California." March 22 2018. https://ngtnews.com/world-energy-acquires-altair-renewable-fuel-assets-in-california; Alt/Air World Energy Paramount, CEQAnet Web Portal, Governor's Office of Planning and Research (June 2020), https://ceqanet.opr.ca.gov/2020069013/2.

226 Delek US Holdings, Inc, Delek US Holdings Announces Closing of Bakersfield Refinery Sale, Global Newswire (May 07, 2020). https://www.globenewswire.com/news-release/2020/05/07/2029947/0/en/Delek-US-Holdings-Announces-Closing-of-Bakersfield-Refinery-Sale.html (accessed Dec 8, 2021).

227 Comments by Biofuelwatch et al dated December 17, 2021 concerning Rodeo Renewed project.

228 Portner 2021, pp. 18-19, 28-29, 53-58.; Searchinger, 2008.

229 Kelly, S., U.S. renewable fuels market could face feedstock deficit, *Reuters* (Apr. 8, 2021), https://www.reuters.com/article/us-usa-energy-feedstocks-graphic/us-renewable-fuels-market-could-face-feedstock-deficit-idUSKBN2BW0EO (accessed Dec 8, 2021).

230 *See e.g.*, Press Release, California Environmental Justice Alliance, IPCC Report Shows Urgent Need to Zero Out Fossil Fuels, Reduce Direct Emissions (Aug. 17, 2021), https://caleja.org/wp.content/uploads/2021/08/CEJA_IPCC_2021-3.pdf; Rachel Smolker, *Bioenergy* in Hoodwinked in the Hothouse: Resist False Solutions to Climate Change, Biofuelwatch, Energy Justice network, Global Alliance for Incinerator Alternatives, ETC Group, Global Justice Ecology Project, Indigenous Climate Action, Indigenous Environmental Network, Just Transition Alliance, La Via Campesino, Movement Generation Justice and Ecology Project, Mt. Diablo Rising Tide, Mutual Aid Disaster Relief, North American Megadam Resistance Alliance, Nuclear Information and Resource Service, Rising Tide North America, Shaping Change Collaborative 19-20 (3d ed. Apr. 2021), https://d5i6is0eze552.cloudfront.net/documents/Destination-deforestation_Oct2019.pdf.

within the biofuel industry[231] itself. Currently planning a biofuel refinery conversion in Bakersfield, Global Clean Energy Holdings, Inc. remarked in its SEC 10-K filing, "[t]he greatest challenge to the wide adoption of [HEFA] renewable fuels is the limited availability of the plant oils and animal fats that are the feedstock of [HEFA] renewable fuels."[232] Given these constraints, a single biofuel conversion project of this magnitude could dramatically induce land use changes and makes the need for a cumulative analysis all the more dire.

The U.S. biofuel industry already consumes a significant portion of existing farm production of oils and animal fats. As shown in Table 10, as of fall 2021, there are eight operating renewable biofuel facilities and 75 biodiesel facilities, with a combined potential capacity of 235,000 barrels per day, or 3.6 billion gallons per year of lipid feedstocks. Meanwhile, the U.S. currently produces 372,000 barrels per day of oils and animal fats for all uses. Thus, at full capacity, these existing projects could consume up to 63% of existing U.S. production. Meanwhile, between these projects, the feedstock actually consumed (which is less than the amount theoretically possible under full production capacity) represented 31% of total U.S. production. *See* Table 9.

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[231] Nickle et al., 2021. Renewable diesel boom highlights challenges in clean-energy transition (Mar 3, 2021), Reuters. https://www.reuters.com/article/us-global-oil-biofuels-insight-idUSKBN2AV1BS.
[232] Global Clean Energy Holdings, Inc., Annual Report (Form 10-K) April 13, 2021, https://www.sec.gov/Archives/edgar/data/748790/000152013821000195/gceh-20201231_10k.htm#a003_v1.

Table 9: US Biofuel Source-Specific Feedstock Production & Consumption

MM t/y: Million Metric tons per year **b/d**: barrel, 42 U.S. gallons, per day

Lipid Type	All-Use US Production		Consumed in US As Biofuel Feedstock		
	Volume (b/d)[a b]	Mass (MM t/y)[a b]	Volume (b/d)[c]	Mass (MM t/y)[c]	As Percentage of US Production (%)
Poultry Fat	22,573	1.1	1,455	0.07	6%
Tallow	51,386	2.68	3,312	0.17	6%
White Grease	13,420	0.75	4,793	0.27	36%
Yellow Grease	18,272	0.96	11,928	0.63	65%
Canola oil	14,425	0.77	10,604	0.56	74%
Corn oil	49,201	2.62	15,249	0.81	31%
Soybean oil	202,672	10.77	66,113	3.51	33%
All Lipids	**371,948**	**19.65**	**112,544**	**6.03**	**31%**

a. US production for poultry fat, tallow (specifically inedible tallow, edible tallow, and technical tallow), white grease (specifically lard and choice white grease), and yellow grease taken from USDA estimates for 2017 through 2020. USDA National Agricultural Statistics Service "Fats and Oils: Oilseed Crushings, Production, Consumption and Stocks" Annual Summaries for 2017 through 2020. National Agricultural Statistics Service, "Fats and Oils: Oilseed Crushings, Production, Consumption and Stocks Annual Summary", 2017 through 2020, https://usda.library.cornell.edu/concern/publications/mp48sc77c. (accessed Dec. 14, 2021). Volume to mass conversions use specific gravities of 0.84, 0.96, and 0.91 for poultry fat, white grease, and yellow grease, respectively. **b.** Production for canola oil, corn oil (which includes distillers' corn oil), and soybean oil taken from USDA Oil Crops Yearbook Tables 5, 26, and 33, averaged from Oct. 2016 to Sept. 2020. USDA, Oil Crops Yearbook Tables 5, 26, and 33, Mar. 26, 2021, https://www.ers.usda.gov/data-products/oil-crops-yearbook/ (accessed Dec. 14, 2021). Volume to mass conversions use specific gravities of 0.914, 0.916, and 0.916 for canola oil, corn oil, and soybean oil, respectively. **c.** Lipid feedstocks consumed for biodiesel production are averages of 2018 through 2020 taken from EIA Monthly Biodiesel Production Report, Table 3. EIA, Monthly Biodiesel Production Report Table 3, Feb. 26, 2021, https://www.eia.gov/biofuels/biodiesel/production/table3.pdf (accessed Dec. 14, 2021). Biofuel feedstock estimates for canola oil are an average of 2019 and 2020 data because 2018 data were suppressed. Volume to mass conversions use specific gravities identified in a. and b.

In recent years, numerous additional biofuel projects have been proposed, with several already under construction. A review of news publications and other reports found 16 future projects either proposed, under construction, or under active consideration by refineries, in addition to the Marathon proposal. In total, these projects could triple the total amount of lipids consumed to a total capacity of 693,000 barrels per day,[233] which would drastically exceed current, total U.S. lipid production. At full production these past and future projects would represent nearly double the entire nation’s output. As a result, it is foreseeable that cumulatively, these projects will require massive increases in domestic oil crop production or foreign imports, either of which will be associated with massive environmental and climate impacts from land use changes.

[233] *See also* findings by EIA that by 2024, U.S. renewable diesel production could total 5.1 billion gal/yr (330,000 b/d) from all projects either under construction, proposed, or announced. Note that this total does not include existing or future lipid-consuming biodiesel projects. Hill et al., U.S. renewable diesel capacity could increase due to announced and developing projects, July 29, 2021. https://www.eia.gov/todayinenergy/detail.php?id=48916 (accessed Dec. 13, 2021).

Table 10: Current and Future Lipid-Based US Biofuel Projects

b/d: barrel, 42 U.S. gallons, per day

Refinery	Site Location	Status	Lipid Feedstock Capacity (b/d)	Lipid Feedstock Capacity As Percentage of US Lipid Yield (%)
East Kansas Agri-Energy Renewable Diesel	Garnett, KS	Operational	206	0.1%
Dakota Prairie Refining LLC	Dickinson, ND	Operational	13,183	3.5%
Diamond Green Diesel LLC	Norco, LA	Operational	23,139	6.2%
REG-Geismar LLC	Geismar, LA	Operational	6,866	1.8%
Wyoming Renewable Diesel CO	Sinclair, WY	Operational	8,033	2.2%
Altair Paramount LLC	Paramount, CA	Operational	2,884	0.8%
American GreenFuels	Encinitas, CT	Operational	2,403	0.6%
Down To Earth Energy LLC	Monroe, GA	Operational	137	0.0%
World Energy Rome	Rome, GA	Operational	1,373	0.4%
Cape Cod Biofuels Inc	Sandwich, MA	Operational	69	0.0%
Maine Bio-Fuel Inc	Portland, ME	Operational	69	0.0%
Blue Ridge Biofuels LLC	Newton, NC	Operational	137	0.0%
Renewable Fuels by Peterson	North Haverhill, NH	Operational	549	0.1%
World Energy Harrisburg LLC	Camp Hill, PA	Operational	1,305	0.4%
Lake Erie Biofuels LLC	Erie, PA	Operational	3,090	0.8%
Newport Biodiesel Inc	Newport, RI	Operational	481	0.1%
Southeast Biodiesel/South Carolina LLC	Charleston, SC	Operational	343	0.1%
Reco Biodiesel LLC	Reco Biodiesel, VA	Operational	137	0.0%
Virginia Biodiesel Refinery LLC	Kilmarnock, VA	Operational	343	0.1%
AG Processing - Algona	Algona, IA	Operational	5,218	1.4%
AG Processing - Sgt Bluff	Sgt Bluff, IA	Operational	5,218	1.4%
REG - Newton	Newton, IA	Operational	2,609	0.7%
REG - Ralston	Ralston, IA	Operational	3,364	0.9%
Lva Crawfordsville Biofuel LLC	Crawfordsville, IA	Operational	687	0.2%
Cargill Inc	Iowa Falls, IA	Operational	3,845	1.0%
Iowa Renewable Energy LLC	Washington, IA	Operational	2,472	0.7%
Reg - Mason City	Mason City, IA	Operational	2,609	0.7%
Western Dubuque Biodiesel LLC	Farley, IA	Operational	2,472	0.7%
Western Iowa Energy LLC	Wall Lake, IA	Operational	3,090	0.8%
Adkins Energy LLC	Lena, IL	Operational	275	0.1%
REG - Danville	Danville, IL	Operational	3,433	0.9%
REG - Seneca	Seneca, IL	Operational	5,218	1.4%

Incobrasa Industries Ltd	Gilman, IL	Operational	3,021	0.8%
Alternative Fuel Solutions LLC	Huntington, IN	Operational	206	0.1%
Integrity Bio-Fuels LLC	Morristown, IN	Operational	343	0.1%
Louis Dreyfus Agricultural Industries LLC	Claypool, IN	Operational	6,797	1.8%
Cargill Inc	Wichita, KS	Operational	4,120	1.1%
Darling Ingredients Inc	Butler, KY	Operational	137	0.0%
Owensboro Grain Biodiesel LLC	Owensboro, KY	Operational	3,708	1.0%
Adrian Lva Biofuel LLC	Adrian, MI	Operational	1,030	0.3%
Thumb Bioenergy LLC	Sandusky, MI	Operational	-	-
Ever Cat Fuels LLC	Isanti, MN	Operational	206	0.1%
Minnesota Soybean Processors	Brewster, MN	Operational	2,472	0.7%
Reg - Albert Lea	Albert Lea, MN	Operational	3,158	0.8%
AG Processing - St. Joseph	St. Joseph, MO	Operational	2,884	0.8%
Deerfield Energy LLC	Deerfield, MO	Operational	3,433	0.9%
Ethos Alternative Energy of Missouri LLC	Lilborne, MO	Operational	343	0.1%
Seaboard Energy Marketing St Joseph	St. Joseph, MO	Operational	2,403	0.6%
Mid-America Biofuels, LLC	Mexico, MO	Operational	3,433	0.9%
Natural Biodiesel Plant LLC	Hayti, MO	Operational	343	0.1%
Paseo Cargill Energy LLC	Kansas City, MO	Operational	3,845	1.0%
Archer-Daniels-Midland Company	Velva, ND	Operational	5,836	1.6%
Cincinnati Renewable Fuels LLC	Cincinnati, OH	Operational	6,248	1.7%
Seaboard Energy Marketing Inc	Guymon, OK	Operational	2,609	0.7%
Bioenergy Development Group LLC	Memphis, TN	Operational	2,472	0.7%
REG - Madison	De Forest, WI	Operational	1,923	0.5%
Walsh Bio Fuels LLC	Mauston, WI	Operational	343	0.1%
Hero Bx Alabama LLC	Moundville, AL	Operational	1,373	0.4%
Delek Renewables Corp	Crossett, AR	Operational	1,030	0.3%
Futurefuel Chemical Company	Batesville, AR	Operational	4,120	1.1%
Solfuels USA LLC	Helena, AR	Operational	2,746	0.7%
Delek US	New Albany, MS	Operational	824	0.2%
Scott Petroleum Corporation	Greenville, MS	Operational	1,167	0.3%
World Energy Natchez LLC	Natchez, MS	Operational	4,944	1.3%
REG - Houston	Seabrook, TX	Operational	3,639	1.0%
World Energy Biox Biofuels LLC	Galena Park, TX	Operational	6,179	1.7%
Delek Renewables LLC	Clerburne, TX	Operational	824	0.2%
Eberle Biodiesel LLC	Liverpool, TX	Operational	-	-
Global Alternative Fuels LLC	El Paso, TX	Operational	1,030	0.3%
Rbf Port Neches LLC	Houston, TX	Operational	9,887	2.7%

Sabine Biofuels II LLC	Houston, TX	Operational	2,060	0.6%
Alaska Green Waste Solutions LLC	Anchorage, AK	Operational	-	-
Grecycle Arizona LLC	Tucson, AZ	Operational	137	0.0%
Crimson Renewable Energy LP	Bakersfield, CA	Operational	1,923	0.5%
American Biodiesel Inc	Encinitas, CA	Operational	1,373	0.4%
Imperial Western Products Inc	Coachella, CA	Operational	824	0.2%
New Leaf Biofuel LLC	San Diego, CA	Operational	412	0.1%
Simple Fuels Biodiesel	Chilcoot, CA	Operational	69	0.0%
Big Island Biodiesel LLC	Keaau, HI	Operational	412	0.1%
Sequential-Pacific Biodiesel LLC	Salem, OR	Operational	824	0.2%
REG - Grays Harbor	Hoquiam, WA	Operational	7,347	2.0%
Marathon[a]	Dickinson, ND	Operational	12,631	3.4%
Camber Energy[b]	Reno, NV	Operational	2,952	0.8%
All Operational Projects			**235,298**	**63.3%**
Global Clean Energy Holdings[c]	Bakersfield	Under Construction	15,000	4.0%
HollyFrontier Corp[d]	Artesia, NM	Under Construction	8,583	2.3%
HollyFrontier Corp[e]	Cheyenne, WY	Under Construction	6,179	1.7%
Diamond Green Diesel[f]	Port Arthur, TX	Under Construction	36,390	9.8%
Diamond Green Diesel[g]	Norco, LA	Under Construction	27,464	7.4%
CVR[h]	Wynnewood, OK	Proposed	6,866	1.8%
Ryze Renewables[i]	Las Vegas, NV	Under Construction	7,894	2.1%
NEXT Renewable Fuels Oregon[j]	Clatskanie, OR	Proposed	50,000	13.4%
Renewable Energy Group[k]	Geismar, LA	Under Construction	17,165	4.6%
World Energy[l]	Paramount, CA	Proposed	21,500	5.8%
Grön Fuels LLC[m]	Baton Rouge, LA	Proposed	66,312	17.8%
PBF[n]	Chalmette, LA	Proposed	24,722	6.6%
Calumet[o]	Great Falls, MT	Proposed	12,631	3.4%
Seaboard Energy[p]	Hugoton, KS	Under Construction	6,842	1.8%
Chevron[q]	El Segundo, CA	Under Construction	10,526	2.8%
CVR Energy[r]	Coffeyville, KS	Under Consideration	11,578	3.1%
Phillips 66[s]	Rodeo, CA	Proposed	80,000	21.5%
Marathon[t]	Martinez, CA	Proposed	48,000	12.9%
All Future Projects			**457,652**	**123.0%**

All Operational & Future Projects		692,950	186.3%

All projects from EIA 2021 "U.S. Renewable Diesel Fuel and Other Biofuels Plant Production Capacity" and "U.S. Biodiesel Plant Production Capacity" reports unless otherwise noted. "-" indicates that capacity data was suppressed in the EIA data. EIA, U.S. Renewable Diesel Fuel and Other Biofuels Plant Production Capacity, Petroleum Reports, Sept. 3, 2021, https://www.eia.gov/biofuels/renewable/capacity/ (accessed Dec. 14, 2021).; EIA, U.S. Biodiesel Plant Production Capacity, Petroleum Reports, September 3, 2021, https://www.eia.gov/biofuels/biodiesel/capacity/ (accessed Dec. 14, 2021). **a.** Frohlke, U. 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Thus, while the impacts of either project standing alone on agricultural resources and land use would be large, the combined impact of the two projects together could be catastrophic in scale – even more so when other existing and planned projects are considered in the cumulative impacts mix. Among other things, this level of market disruption would greatly increase that likelihood that other types of fungible food crop oils – including palm oil – would start to replace the dwindling supply of soy and other food crop oils, with attendant destructive impacts. The sheer amount the land required to grow food crop oils for existing and projected biofuel projects domestically indicates dramatic land use changes will inevitably occur at a global scale. Despite the novelty of this type of refinery conversion in California, even just the national data shows the Project is entering a large biodiesel market which has already contributed to the significant indirect land use changes documented in Section VI above.

B. The DEIR Should Have Analyzed the Cumulative Impact of California Biofuel Production on the State's Climate Goals[234]

As discussed in Section VI, large-scale biofuel production is incompatible with California's climate goals, which contemplate large-scale electrification via BEVs, and a phase-out of combustion fuel. That impact cannot be fully disclosed, measured, and analyzed, however, without looking at the cumulative impact of all of the biofuel production existing or contemplated in the state. The DEIR erred in not undertaking that analysis.

Within the fuel market, "renewable" diesel production targeting the California fuels market has already been growing at an increasingly rapid rate since 2011.[235] Growing by a factor of 65 times to 2.79 million barrels per year (MM b/y) as of 2013, by 142 times to 6.09 MM b/y as of 2016, and 244 times to 10.5 MM b/ya as of the end of 2019.[236] Planned new HEFA capacity targeting the California fuels market and planned for production by 2025 totals approximately 124 MM b/y, another potential increase of more than tenfold from 2019-2025.[237]

Current proposals to repurpose in-state crude refining assets for HEFA biofuels could exceed the biofuel caps in state climate pathways by 2025. New in-state HEFA distillate (diesel and jet fuel) production proposed by this Project, the Marathon, AltAir, and the Global Clean Energy (GCE) projects for the California fuels market would, in combination, total ~2.1 billion gal./y and is planned to be fully operational by 2025.[238] If fully implemented, these current plans alone would exceed the HEFA diesel and jet fuel caps of 0.0-1.5 billion gal./y in state climate pathways.

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[234] Additional support for this section is provided in Karras, 2021a.

[235] Data from Share of Liquid Biofuels Produced In State by Volume; Figure 10 in Low Carbon Fuel Standard Data Dashboard, California Air Resources Board, https://ww3.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm.

[236] *Id.*

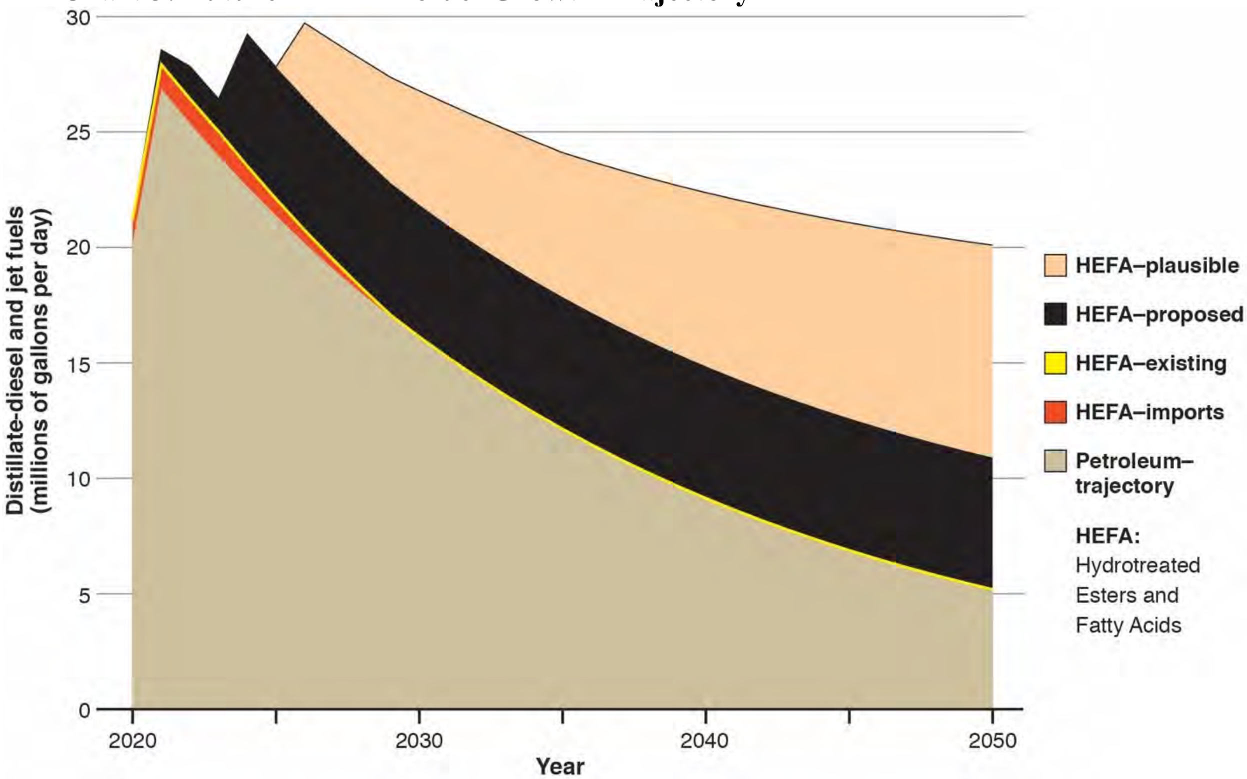
[237] *See* CEC 2021 Schremp Presentation.

[238] Supporting Material Appendix for 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, www.energy-re-source.com; Application for Authority to Construct Permit and Title V Operating Permit Revision for Rodeo Renewed Project: Phillips 66 Company San Francisco Refinery (District Plant No. 21359 and Title V Facility # A0016); Prepared for Phillips 66 by Ramboll US Consulting, San Francisco, CA. May 2021; Initial Study for: Tesoro Refining & Marketing Company LLC—Marathon Martinez Refinery Renewable Fuels Project; received by Contra Costa County Dept. of Conservation and Development 1 Oct 2020; April 28, 2020 Flare Event Causal Analysis; Tesoro Refining and Marketing Company, subsidiary of Marathon Petroleum, Martinez Refinery Plant #B2758; report dated 29 June, 2020 submitted by Marathon to the Bay Area Air Quality Management District: San Francisco, CA. https://www.baaqmd.gov/about-air-quality/research-and-data/flare-data/flare-causal-reports ; Paramount Petroleum, AltAir Renewable Fuels Project Initial Study; submitted to City of Paramount Planning Division, 16400 Colorado Ave., Paramount, CA. Prepared by MRS Environmental, 1306 Santa Barbara St., Santa Barbara, CA; Brelsford, R. Global Clean Energy lets contract for Bakersfield refinery conversion project. Oil & Gas Journal. 2020. Jan.9, 2020.

Further HEFA biofuels growth could also exceed total liquid fuels combustion benchmarks for 2045 in state climate pathways. As BEVs replace petroleum distillates along with gasoline, crude refiners could repurpose idled petroleum assets for HEFA distillates before FCEVs ramp up, and refiners would be highly incentivized to protect those otherwise stranded assets.

Chart 3 illustrates a plausible future HEFA biofuel growth trajectory in this scenario. Declining petroleum diesel and jet fuel production forced by gasoline replacement with BEVs (gray-green, bottom) could no longer be fully replaced by currently proposed HEFA production (black) by 2025–2026. Meanwhile the idled crude refinery hydrogen production and processing assets repurpose for HEFA production (light brown, top). As more petroleum refining assets are stranded, more existing refinery hydrogen production is repurposed for HEFA fuels, increasing the additional HEFA production from left to right in Chart 3.

Chart 3: Future HEFA Biofuel Growth Trajectory



Combustion fuels additive potential of HEFA diesel and jet production in California. As electric vehicles replace gasoline, stranding petroleum refining assets, continuing HEFA biorefining expansion could add as much as 15 million gallons per day (290%) to the remaining petroleum distillate-diesel and jet fuel refined in California by 2050. Locking in this combustion fuels additive could further entrench the incumbent combustion fuels technology in a negative competition with cleaner and lower-carbon technologies, such as renewable-powered hydrogen fuel cell electric vehicles (FCEVs). That could result in continued diesel combustion for long-haul freight and shipping which might otherwise be decarbonized by zero emission hydrogen-fueled FCEVs. **Petroleum-trajectory** for cuts in petroleum refining of distillate (D) and jet (J) fuels that will be driven by gasoline replacement with lower-cost electric vehicles, since petroleum refineries cannot produce as much D+J when cutting gasoline (G) production. It is based on 5.56%/yr light duty vehicle stock turnover and a D+J**:**G refining ratio of 0.615. This ratio is the median from the fourth quarter of 2010–2019, when refinery gasoline production is often down for maintenance, and is thus relatively conservative. Similarly, state policy targets a 100% zero-emission LDV fleet by 2045 and could drive more than 5.56%/yr stock turnover. Values for 2020-2021 reflect the expected partial rebound from COVID-19. **HEFA-imports** and **HEFA-existing** are the mean D+J "renewable" volumes imported, and refined in the state, respectively, from 2017-2019. The potential in-state expansion shown could squeeze out imports. **HEFA-proposed** is currently proposed new in-state capacity based on 80.9% D+J yield on HEFA feed including the Phillips 66 Rodeo, Marathon Martinez, Altair Paramount, and GCE Bakersfield projects, which represent 47.6%, 28.6%, 12.8%, and 11.0% of this proposed 5.71 MM gal/day total, respectively. **HEFA-plausible:** as it is idled along the petroleum-based trajectory shown, refinery hydrogen capacity is repurposed for HEFA biofuel projects, starting in 2026. This scenario assumes feedstock and permits are acquired, less petroleum replacement than state climate pathways, and slower HEFA growth than new global HEFA capacity expansion plans targeting the California fuels market[ii] anticipate. Fuel volumes supported by repurposed hydrogen capacity are based on H_2 demand for processing yield-weighted feedstock blends with fish oil growing from 0% to 25%, and a J **:** D product slate ratio growing from 1: 5.3 to 1: 2, during 2025–2035. For conceptual analysis *see* Karras, 2021a; for data and methodological details see Karras, 2021a Table A7. [239]

[239] Supporting Material Appendix for 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.

Refining and combustion of HEFA distillates in California could thus reach ~15.0 million gal./d (5.47 billion gal./y), ~290% of the remaining petroleum distillates production, by 2050.[240] HEFA distillate production in this scenario (5.47 billion gal./y) would exceed the 1.6-3.3 billion gal./y range of state climate pathways for combustion of *all* liquid transportation fuels, including petroleum and biofuel liquids, in 2045.[241] This excess combustion fuel would squeeze out cleaner fuels, and emit future carbon, from a substantial share of the emergent petroleum distillate fuels replacement market — a fuel share that HEFA refiners would then be motivated to retain.

The scenario shown in Chart 3 is an illustration, not a worst case. It assumes slower growth of HEFA biofuel combustion in California than global investors anticipate, less petroleum fuels replacement than state climate pathways, and no growth in distillates demand. Worldwide, the currently planned HEFA refining projects targeting California fuel sales total ~5.2 billion gal./y by 2025.[242] HEFA growth by 2025 in the Chart 3 scenario is less than half of those plans. Had the DEIR considered that 5.2 billion gallon/year estimate by California Energy Commission staff,[243] for example, the County could have found that the Project would contribute to exceeding the state climate pathway constraint discussed in Section V of 0.5–0.6 and 0.8–0.9 billion gallons/year total HEFA jet fuel, and HEFA diesel combustion, respectively, based on that fact alone. Additionally, State climate pathways reported by Mahone et al. replace ~92% of current petroleum use by 2045, which would lower the petroleum distillate curve in Chart 3, increasing the potential volume of petroleum replacement by HEFA biofuel. Further, in all foreseeable pathways, refiners would be incentivized to protect their assets and fuel markets.

The cumulative emission shifting associated with biofuel production (Section VI) is also highly significant. A *conservative* estimate of cumulative emissions from currently proposed refinery biofuel projects in the County, *if* state goals to replace all diesel fuels were to be achieved more quickly than anticipated, is in the range of approximately 74 Mt to 107 Mt over ten years. *See* Table 8.

C. The DEIR Did Not Adequately Disclose and Analyze Cumulative Marine Resources Impacts

There is currently a boom in proposals for biofuel conversions. Unlike existing fossil fuel refining, there is little existing transportation infrastructure for biofuel feedstocks, so, as with the Project, much of that transportation will take place via ship. This means that there will be cumulative impacts to marine resources that have not been adequately evaluated in the DEIR.

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[240] *Id.*

[241] Mahone et al., 2020a. Achieving Carbon Neutrality in California: PATHWAYS Scenarios Developed for the California Air Resources Board, DRAFT: August 2020; Energy and Environmental Economics, Inc.: San Francisco, CA. https://ww2.arb.ca.gov/sites/default/files/2020-08/e3_cn_draft_report_aug2020.pdf

[242] Schremp (2020). Transportation Fuels Trends, Jet Fuel Overview, Fuel Market Changes & Potential Refinery Closure Impacts. BAAQMD Board of Directors Special Meeting, May 5 2021, G. Schremp, Energy Assessments Division, California Energy Commission. In Board Agenda Presentations Package; https://www.baaqmd.gov/-/media/files/board-of-directors/2021/bods_presentations_050521_revised_op-pdf.pdf?la=en

[243] *Id.*

For example, increases in feedstock demand will implicate economic and transportation impacts to marine resources all over the world.

While the DEIR mentions in passing the Phillips 66 biofuel conversion proposal, it does not evaluate other biofuel proposals or their cumulative impacts.

> With marine vessel traffic and renewable feedstock and fuels transportation also a component of the Phillips 66 Rodeo Renewed Project, there is greater opportunity for introduction of non-native invasive species, vessel strikes and spills, even with mitigation measures implemented by the Project as described in Section 3.4. Therefore, the Project would contribute to a cumulatively significant impact on biological resources.

DEIR 4-10. These other projects, both in California and around the country, must be evaluated. For instance, vessel traffic increases will be cumulatively significant.

In 2017 Phillips 66 proposed a marine terminal expansion. According to the Project Description for that project, it was to

> modify the existing Air District permit limits to allow an increase in the amount of crude and gas oil that may be brought by ship or barge to the Marine Terminal at the Phillips 66 Company (Phillips 66} San Francisco Refinery in Rodeo, California (Rodeo Refinery). The refinery processes crude oil from a variety of domestic and foreign sources delivered by ship or barge at the Marine Terminal and from central California received by pipeline. The Proposed Project would allow the refinery to receive more waterborne-delivered crude and gas oil, and thereby to replace roughly equivalent volumes of pipeline-delivered crudes with waterborne-delivered crudes. However, the Proposed Project would not affect the characteristics of the crude oil and gas oil the refinery is able to process.
>
> The proposed increase in offloading and the additional ship and barge traffic necessitates modification of Phillips 66's existing Permit to Operate and the Major Facility Review (Title V) Permit, which was issued by the Air District to the Phillips 66, San Francisco Refinery (BAAQMD Facility #A0016). Approval of the proposed air permit modifications would be a discretionary action by the Air District, requiring CEQA review (BAAQMD Regulation 2-1-310).

Phillips 66 Marine Terminal Permit Revision Project, Notice of Preparation, June 2017, p. 2. The final EIR must evaluate past proposals such as the 2017 marine terminal expansion proposal, to determine whether there are cumulative impacts and whether those proposals are likely to be approved.

The record for BAAQMD's analysis of the Phillips 66 2017 project proposal should be incorporated into the record for the current CEQA review; as should the record associated with the proposed terminal expansion associated with the Phillips 66 Rodeo Renewed project.

X. THE DEIR SHOULD HAVE MORE FULLY ADDRESSED HAZARDOUS CONTAMINATION ISSUES ASSOCIATED WITH CONSTRUCTION AND DECOMMISSIONING

The DEIR failed to adequately address the interrelated issues of site decommissioning and contamination hazards. The Refinery site is heavily contaminated, which gives rise to issues concerning both how decommissioned portions of the refinery will be addressed, and how Project construction and operation may affect ongoing remediation and monitoring activities. Additionally, given the likely short and definably finite commercial lifetime of the Project, the DEIR should have evaluated the impact of full site decommissioning.

The DEIR provides general references to existing contamination in its discussion of existing conditions (DEIR 3.9-8 – 9), construction impacts on hazardous waste remediation activities (DEIR 3.9-13), and decommissioning portions of the site (DEIR 2-39). However, the DEIR provides insufficient detail concerning the extent of existing contamination to the soil and groundwater, or concerning past cleanup operations currently being monitored. The analysis does reference Order No. 00-021 (DEIR at 3.9-13), but not the various past hazardous waste management activities that are completed but still subject to monitoring requirements. Ongoing hazardous waste remediation activities are being conducted under the jurisdiction of the Department of Toxic Substances Control (DTSC), which involve a land use restriction.[244] The U.S. Environmental Protection Agency (EPA) and the San Francisco Regional Water Board (Water Board) have also issued multiple past orders. EPA Resource Conservation and Recovery Act (RCRA) Order No. 09-89-0013 was issued March 13, 1989; and Waste Discharge Requirements Order R2-2004-0056 was issued in July 2004.[245] The San Francisco Bay Regional Board (Regional Board), overseeing the cleanup, issued cleanup orders for Waste Management Units (WMUs) 10, 11, 14, 31, and 32 in 2017.[246] The Regional Board approved post-closure management plans for Waste Management Units (WMUs) 1, 2, 3, 4, 5, 6, 8, 9, and 13in 2015.[247]

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[244] DTSC activities include the individual Waste Management Unit (WMU), WMU-17, US EPA number CAD000072751. The latest Post Closure Facility Permit is effective 12/19/21 and will expire 12/18/31. Number 7 of Section V Special Conditions of the Post Closure Permit specifies that a Land Use Covenant was filed 9/10/20 based on the DTSC has concluded that it is reasonably necessary to restrict the land use of the Unit in order to protect present or future human health or safety or the environment. *See* Land Use Covenant And Agreement Environmental Restrictions County of Contra Costa Assessor's Parcel Number: 159-270-006, Tesoro Refining & Marketing Company LLC DTSC Site Code: 510505: September 10, 2020; Hazardous Waste Management Program Permitting Division, Post-Closure Hazardous Waste Facility Permit for Tesoro Refining and Marketing Company LLC. Permit No. 2021/22-HWM-05, EPA ID No CAD 000 072 751, effective date December 19, 2021.

[245] Letter dated July 30, 2004 to Tesoro Refining and Marketing Company from David Elias, Regional Board.

[246] Letter dated September 1, 2016 to Frances Malamud-Roam from Michael McGuire re Revised Alternatives Analysis, Tesoro Martinez Refinery Waste Management Unit Closure Project.

[247] Letter dated July 29, 2015 to Regional Board from Michael McGuire re Post-Closure Maintenance Plan (PCMP) for Waste Management Units 1, 2, 3, 4, 5, 6, 8, 9..

Yet only WMU 4 receives mention in the DEIR (in the discussion of cultural impacts, DEIR 3.5.5).

The DEIR should have disclosed in detail all of these historic and ongoing cleanup and monitoring operations, and described the basis for its cursory conclusion that construction and operation activities will not impact them (DEIR at 3.9-13). Additionally, the DEIR should have discussed how the Project will impact transportation routes around ongoing remediation. For example, the transfer route of waste from WMU 31 into WMU 14 must traverse the Waterfront Road which, is the main road leading to the active refinery.

The DEIR should also have provided further detail regarding decommissioning plans with respect to the portions of the Refinery that will be fallowed by the Project, beyond the cursory description at DEIR 2-39. The idled equipment, and the ground on which it is located, is likely to be highly contaminated from years of operation of the refinery. The DEIR should have discussed what specifically will be done with the equipment, and how Marathon will address contamination of soil and groundwater at the location of the idled equipment.

Finally, the DEIR should have evaluated the impact of full site decommissioning, given the likely limited lifespan of the Project. As discussed in Section II, the foreseeable likelihood is that biofuel demand in California will wane significantly within the relatively near term as California transitions to a zero-emissions transportation economy. As noted, Contra Costa County itself has signed a pledge to be "diesel free by '33." Accordingly, the realistic likelihood is that the Project's commercial life will be short. Thus, in order to fully inform that public regarding foreseeable impacts, and to guide the County's thinking about planning for the Project site's future, the DEIR should have examined the impacts of full decommissioning of the site (even though such full decommissioning was rejected as a Project alternative).

Such analysis of full decommissioning should take into account the fact that various oil companies refined oil at the Martinez site since 1913, roughly 60 years before the environmental protection wave of the early 1970s, and through waves of toxic gasoline additives—tetraethyl lead and then MTBE, from the 1930s through the early 2000s—and refinery releases to land persist to this day.

XI. THE DEIR INADEQUATELY ADDRESSED THE PROJECT'S IMPACTS ON MARINE RESOURCES

The DEIR inadequately addresses multiple aspects of potential Project impacts on marine resources. This failure is problematic given that, as discussed in Section II, the Project appears to contemplate an increase in ship traffic, even assuming that the chosen baseline is correct (which it is not, per Section III).

A. Increased Marine Traffic and Terminal Throughput Would Result in Significant Water Quality Impacts, With Attendant Safety Hazards

The water quality impacts from any increase in ship traffic or throughput volumes, as identified in Section III, must be thoroughly examined in all their phases. These include, at minimum, the loading process of feedstocks onto tankers and the shipping routes they take to San Francisco Bay, the unloading of those feedstocks and transport into the refinery, the separation and reuse or disposal of unused portions or diluents, the eventual shipment of refined or reused products to end markets, and finally through to impacts from the use of end products. This lifecycle analysis must take into account global effects such as climate change and ocean acidification, as well as local water quality impacts that could have serious consequences for the communities at production sites, ports, along the shipping routes, and near the actual Project site in Martinez. This analysis must also disclose the extent to which unknowns exist, such as the lack of concrete information concerning effective marine spill cleanup methodologies for feedstocks and the environmental impacts of such spills, and evaluate the risks taken as a result of those unknowns.

Each tanker trip carries an added risk of a spill, as a reported 50% of large spills occur in open water.[248] The majority of spills, however, are less than 200,000 gallons, and most of these spills happen while in port.[249] Two types of tanker will likely be used to transport feedstocks to the Facility, ocean-going tankers and barges. The final EIR must evaluate an actual worst-case spill scenario and mitigate appropriately.

California's 45-billion-dollar coastal economy has a lot to lose to a spill.[250] California commercial fisheries for instance, produced from 186-361 million pounds of fish from 2013-2015, at a value of 129-266 million dollars.[251] After the Costco Busan disaster spilled 53,000 gallons of oil into San Francisco Bay, the Governor closed the fishery, a significant portion of which was either contaminated or killed, closed more than 50 public beaches, some as far south as Pacifica, and thousands of birds died. All told that spill resulted in more than 73 million dollars in estimated damages and cleanup costs.[252]

A DEIR evaluating the environmental impacts of expanding operations at the Marathon marine terminals must take into account the increased risk of a spill into San Francisco Bay or at any other point along the route transport tankers and barges will take. Any increase in risk is considered to be a significant impact. However, the DEIR fails to evaluate impacts from the handling of hazardous materials along transportation corridors, and from the presence of hazardous materials along shorelines in the event of a spill. The final EIR must remedy this error.

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248 The International Tanker Owners Pollution Federation (2016 spill statistics) at 8.
249 *Id.*
250 *California Ocean and Coastal Economies*, National Ocean Economics Program (March 2015).
251 Based on California Department of Fish and Wildlife and National Marine Fisheries Service data.
252 *See, e.g., Incident Specific Preparedness Review M/V Cosco Busan Oil Spill in San Francisco Bay Report on Initial Response Phase*, Baykeepr, OSPR, NOAA, et al. (Jan. 11, 2008).

Uncertainty over how to clean up spills of feedstocks extends to the specific technology used for cleanup efforts. "The environmental impacts associated with oil spill clean-up efforts (e.g. mechanical or chemical) may increase the magnitude of ecological damage and delay recovery."[253] Recent surveys have not found any studies on the response of "trophic groups within eelgrass and kelp forest ecosystems to bitumen in the environment, or the impacts of different spill-response methods."[254] The final EIR must do more to evaluate these impacts.

There are additional mitigation measures that should be considered and included in the final EIR to help mitigate spill risk. First, all ships carrying feedstocks, petroleum products, or any other hazardous material that could spill into San Francisco Bay or any of the other waters along the Project's transport routes should be double-hulled. "Recent studies comparing oil spillage rates
from tankers based on hull design seem to suggest that double hull tankers spill less than pre-MARPOL single hull tankers, double bottom tankers, and double sided tankers."[255] Second, incentives for vessel speed reductions, as well as documentation and tracking of vessel speeds, as detailed elsewhere in these comments, would also reduce spill risks. Finally, additional yearly funding for the study of feedstock spills, the impact of such spills, and the most effective cleanup and mitigation methodologies would also help mitigate this risk and should be included in the final EIR.

A recent spill at the Phillips 66 Marine Terminal serves as a warning of what could result from increased marine terminal operations. According to press reports, "BAAQMD issued two 'public nuisance' violations to Phillips 66 for its Sept. 20, 2016 spill, which leaked oil into the bay and sent an estimated 120 people to the hospital from fumes."[256] That spill, which occurred while the Yamuna Spirit was offloading at the Phillips 66 Marine Terminal in Rodeo, was responsible for more than 1,400 odor complaints and a shelter-in-place order for the 120,000 residents of Vallejo, in addition to the hospital visits already mentioned.[257]

The 120 people who went to the hospital in Vallejo would probably agree that a release from the marine terminals would represent a significant safety hazard. Spill events are also high variance, in that they are relatively unlikely to occur, and high impact, in that the repercussions of such an event have the potential to cause extensive damage. Typical baseline analysis, therefore, is inappropriate. A baseline analysis that said there was no risk of tanker spills based on baseline data from the previous 3 years, for instance, would be clearly inadequate in hindsight after an event

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[253] Green *et al*., 2017
[254] *Id*.
[255] *A Review of Double Hull Tanker Oil Spill Prevention Considerations*, Nuka Research & Planning Group, LLC. (Dec. 2009), p. 3, *available at* https://www.pwsrcac.org/wp-content/uploads/filebase/programs/oil_spill_prevention_planning/double_hull_tanker_review.pdf.
[256] Katy St. Clair, "Supervisor Brown says 'no way' to proposed Phillips 66 expansion," Times-Herald (Aug. 5, 2017), *available at* http://www.timesheraldonline.com/article/NH/20170805/NEWS/170809877; *see also* Ted Goldberg, "Refinery, Tanker Firm Cited for Fumes That Sickened Scores in Vallejo," KQED News (June 16, 2017), *available at* https://ww2.kqed.org/news/2017/06/16/refinery-tanker-firm-cited-for-fumes-that-sickened-scores-in-vallejo/; Ted Goldberg, "Phillips 66 Seeks Huge Increase in Tanker Traffic to Rodeo Refinery," KQED News (July 27, 2017) (", *available at* https://ww2.kqed.org/news/2017/07/27/phillips-66-seeks-big-increase-in-tanker-traffic-to-rodeo-refinery/.
[257] Ted Goldberg, "Refinery, Tanker Firm Cited for Fumes That Sickened Scores in Vallejo," *id*.

like the Exxon Valdez. So, too, here, spill risk in the final EIR must be calculated and mitigated based on the worst-case scenario, not on a baseline compiled over recent years that do not include any major oil spills.

In light of these concerns, Contra Costa must consider an independent study on feedstock cleanup, the adequacy of existing cleanup procedures and the need for additional cleanup and restitution funds, and increased monitoring for water and air quality impacts to communities surrounding the Project, whether those communities are located in the same county or not. Furthermore, the Bay Area Air Quality Management District should be considered as a responsible agency.

As pointed out by California State Senator Bill Dodd, it is vital that the causes of this spill be thoroughly investigated and a determination made on how such a spill can be prevented in the future.[258] Such an investigation must be completed before any additional ships are authorized to use the same marine terminal where the spill was reported. Without a thorough report on past spills that includes a description of what happened and how such accidents can be prevented in the future, the DEIR will not be able to adequately evaluate the Project's potential environmental impacts.

Additional National Pollutant Discharge Elimination System ("NPDES") effluent criteria may be needed, a possibility which must be—but is not substantially—evaluated in the DEIR. DEIR 3.10-17 ("new facilities would generate a new wastewater stream that would require additional treatment equipment to be added to the existing wastewater treatment plant"). Foreseeable spill rates from an increase in marine terminal activity might qualify as a discharge to waters of the United States because it is reasonably predictable that a certain number of spills will occur. With this and other water quality impacts in mind, the regional water board should at least be another responsible agency, if not the lead agency evaluating a permit to increase marine terminal operations. Furthermore, as stated, different feedstock will result in a change in the effluent discharged by the refinery under their existing NDPES permit, another reason why the regional water board should at least be a responsible party. The DEIR must evaluate an updated NPDES permit that reflects the changing feedstock that will result from the Project instead of putting such analysis off until after the Project is completed.

No reasonable mitigation or planning can be done with regard to the risk posed by the transport of feedstocks to the Phillips 66 refinery in Rodeo without specific information as to the chemical composition of the feedstocks being transported. Details on the types of feedstocks expected to arrive on the tankers utilizing the marine terminals' expanded capacity must be part of the DEIR and must be made publicly available. It is irresponsible to conduct risk assessment and best practices for the handling of feedstocks without at least knowing exactly what the chemical composition of the feedstock is, and how it differs from conventional oil. Additional research into best management practices, spill prevention practices, and cleanup and response planning is needed before permitting a major increase in the amount of refinery-bound tanker traffic coming into California's waters.

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[258] *See* Senator Bill Dodd, Letter Re: Vallejo Odor and Bay Area Air Quality Management District Response (March 8, 2017), *available at* https://www.documentcloud.org/documents/3514729-Sen-Dodd-BAAQMD-Letter-3-8-17.html.

We ask that the final EIR contain and make publicly available an independent scientific study on the risks to – and best achievable protection of – state waters from spills of feedstocks. This study should evaluate the hazards and potential hazards associated with a spill or leak of feedstocks. The study should encompass potential spill impacts to natural resources, the public, occupational health and safety, and environmental health and safety. This analysis should include calculations of the economic and ecological impacts of a worst-case spill event in the San Francisco Bay ecosystem, along the California coast, and along the entire projected shipping route for the expanded marine terminal.

Based on this study, the final EIR should also include a full review of the spill response capabilities and criteria for oil spill contingency plans and oil spill response organizations (OSROs) responsible for remediating spills. We respectfully request that the final EIR include an analysis indicating whether there are OSROs currently operating in California capable of responding adequately to a spill of the contemplated feedstocks. Further, the adequacy of an OSRO's spill response capability should be compared to the baseline of no action rather than to a best available control technology standard.

While California's regulatory agencies have recently been granted cleanup authority over spills of biologically-derived fuel products, no such authority or responsibility has been granted for feedstocks. If there are no current plans for OSROs to respond to spills of feedstocks in California waters, the final EIR must evaluate the impacts of such a spill under inadequate cleanup scenarios. The DEIR fails to adequately evaluate how spills of feedstocks will be remediated, if at all.

Additional ships delivering oil to the Project would be passing through a channel that the Army Corps of Engineers has slated for reduced dredging. The Project thus contemplates increasing ship traffic through a channel that could be insufficiently dredged. The final EIR must evaluate the safety risks posed by reduced Pinole Shoal Navigation Channel Maintenance Dredging.[259] Should Marathon be required to dredge the channel, it must fully evaluate and disclose impacts from such dredging in its environmental analysis.

Finally, the final EIR must evaluate ship maintenance impacts. Increased shipping means increased maintenance in regional shipyards and at regional anchorages, and these impacts must be analyzed.

B. The DEIR Wrongly Concludes There Would be No Aesthetic Impacts

The DEIR claims that there would be little aesthetic impact, and fails to analyze the impacts to marine environment-related aesthetics. DIER 3.2. San Francisco Bay is considered a world class scenic vista, with billions of dollars of tourism dependent on a setting of natural beauty. Yet minimal analysis has been done of what impact ship traffic would have on San Francisco Bay's aesthetics, including a significant source of light or glare (ships). Changes in

[259] Memorandum for Commander, South Pacific Division (CWSPD-PD), FY 17 O&M Dredging of San Francisco (SF) Bay Navigation Channels, U.S. Army Corps of Engineers (Jan. 12, 2017) (Army Corps memo discussing deferred dredging).

the types of ships serving the Facility and the times of day those ships are traversing San Francisco Bay are also relevant. The final EIR must take a hard look at these impacts, as well as impacts along expected transportation corridors and impacts from spill risks.

C. Air Quality Impacts Must Be Evaluated for an Adequate Study Area

Air quality impacts evaluated by the DEIR must include an adequate study area in order to appropriately estimate the Project's potential to result in substantial increases in criteria pollutant emissions. Air quality impacts from ship exhaust must be evaluated. These impacts must be evaluated by location, as is done for other types of impacts, for different types of ships, for every mile the ships travel, and for every community along their route, not just between the refinery and various anchorage points or arbitrary starting points such as the Golden Gate Bridge. The DEIR fails to do so, and also fails to evaluate health impacts from these routes and at various locations.[260] For instance, DEIR Table 3.3-5 evaluates only total mobile emissions, and fails to break out these emissions by source type. Impacts vary widely based on where the emissions are taking place, at sea or on land, etc. Under CEQA, the public must be informed in greater detail as to potential impacts from mobile sources. Ships will not arrive at the Project terminals from out of a vacuum, and each additional ship beyond those currently in fact using the terminal – not just those currently permitted – must be evaluated.

Marathon does not have a good record of avoiding air quality violations at its refinery. For instance, Marathon Petroleum this year settled 58 violations stretching back to 2014. These violations included a "55-day flaring event in 2014, [during which] the refinery emitted enormous amounts of volatile organic compounds, hydrogen sulfide, sulfur dioxide and methane emissions, according to the Bay Area Air Quality Management District."[261] Such past violations must be evaluated when considering the likelihood of future violations that may relate to a change in feed stock or increased refinery activity as a result of the refinery's operations, including marine terminal operations.

Provision of shore power for all ships at Marathon's terminals should also be considered as a mitigation measure prior to the 2027 implementation of California's *Ocean-Going Vessels at Berth Regulation*, described in the DEIR at 3.3-18 – 3.3-19. No implementation of these regulation is contemplated by the DEIR beyond the vague premise that the marine terminals will comply once they are forced to do so by the Air Board. The final EIR should include

[260] Again, the DEIR confusingly piecemeals its analysis. Instead of including an easily producible table in the DEIR, it refers the public to various appendices (and even appendices to appendices) to attempt to calculate for themselves the air quality impacts of marine operations from the proposed Project. DEIR 3.3-28. Even these appendices are inadequate, as the DEIR acknowledges that it does not include all potential ship and barge traffic in its analysis. *Id*. (dividing out barge trip analysis from ocean-going vessels and admitting that "[b]arges <u>may</u> be used to transport feedstocks from third party terminals. The specific terminals have not yet been identified," emphasis added). According to one appendix, "[e]missions are calculated for the round-trip starting from the Pilot Boarding/Sea Buoy location (approximately 11 nautical miles west of the Golden Gate Bridge) to the relevant terminal." DEIR Appendix AQ-GH 15. Truncating trips like this is arbitrary and fails to accurately reflect the impact of the Project. The ships do not magically appear just outside the Golden Gate Bridge.

[261] *Marathon to pay $2 million for air quality violations at idled Martinez oil refinery*, Mercury News, Sept. 29, 2021, *available at* https://www.mercurynews.com/2021/09/29/marathon-to-pay-2-million-for-air-quality-violations-at-idled-martinez-oil-refinery/.

implementation details and timelines. Other mitigation that should be implemented include incentives for ship emissions and speed reductions that would result in air quality improvements.

According to the DEIR, mobile sources for the marine terminals are calculated using outdated EIRs from 2014 and 2015. DEIR 3.3-26 – 3.3-27. These EIRs are outside even the generous baseline contemplated in the DEIR. Average activity levels must be calculated based on actual operations, and cannot be tiered off of outdated EIRs.

D. Recreational Impacts Are Potentially Significant

The DEIR states that "the Project would have no impact to recreation. DEIR 3.1-8. This is error. San Francisco Bay is a massive recreational area, and maritime traffic has a direct impact on opportunities for recreation on the Bay. Ship traffic qualifies as substantial physical deterioration of an existing facility. In addition, spills of feedstocks or finished products either from ships moving to and from the refinery or from the refinery itself have the potential to impact existing recreational sites. The DEIR contemplates product carried by ship across the Pacific Ocean and through San Francisco Bay, and each additional trip carries with it an increased chance of a spill. The final EIR must evaluate recreational impacts from increased ship traffic and spill risk, both in San Francisco Bay and at every point along contemplated transportation corridors.

E. The Project Implicates Potential Utilities and Service System Impacts

The increase in maritime traffic has a direct impact on ship maintenance, anchorages, and upkeep on the Bay. Increased ship traffic would accelerate deterioration of existing facilities. In addition, spills of feedstocks or finished products either from ships moving to and from the refinery or from the refinery itself have the potential to impact existing ship facilities. The DEIR contemplates a huge increase in the amount of product carried by ship across the Pacific Ocean, through the Delta, and through San Francisco Bay, and each additional trip carries with it an increased chance of a spill. The final EIR must evaluate utility and service system impacts from increased ship traffic and spill risk, both in San Francisco Bay and at every point along contemplated transportation corridors.

F. Biological Impacts and Impacts to Wildlife are Potentially Significant and Inadequately Mitigated

The DEIR makes clear that there are numerous special status marine and aquatic species present (*see, e.g.*, DEIR 3.4-8, 3.4-10 – 3.4-25), yet does not sufficiently protect these species. For each of the following impact areas, we request that adequate mitigation be evaluated and applied for each species type. Reference to EIRs from 2014 and 2015 is insufficient as conditions have changed since then, as mentioned earlier. *See, e.g.*, DEIR 3.4-34 (though these outdated EIRs are cited repeatedly with no evaluation of whether their analyses is still relevant).

Increased shipping as a result of biofuel production and transport causes stress to the marine environment and can thus impact wildlife. Wake generation, sediment re-suspension, noise pollution, animal-ship collisions (or ship strikes), and the introduction of non-indigenous species must all be studied as a part of the EIR process. "Wake generation by large commercial vessels has been associated with decreased species richness and abundance (Ronnberg 1975) given that wave forces can dislodge species, increase sediment re-suspension (Gabel et al. 2008), and impair foraging (Gabel et al. 2011)."[262] Wake generation must be evaluated as an environmental impact of the Project.

The DEIR contains ample data supporting vessel speed reduction as a means to avoid adverse impacts from ship strikes. *See, e.g.*, DEIR 3.4-40. Yet vessel speed reductions are not mandatory, and there is no requirement that the increased vessel traffic contemplated by the Project would adhere to speed recommendations to protect wildlife. The mitigation measures proposed by the DEIR amount to nothing more than sending some flyers. The final EIR should contemplate additional mitigation that includes tracking actual vessel speeds and incorporates mitigation for vessels that exceed 10 knots, as well as incentives for vessels to adhere to recommended speeds such as monetary bonuses or fines. Mitigation Measures BIO-7(b) is insufficient because it does not contemplate effective measures to ensure safe vessel speeds and to mitigate for exceedances.

Acoustic impacts can also be extremely disruptive. As the DEIR points out, "[s]hips are the dominant source of low frequency noise in many highly trafficked coastal zones." DEIR 3.4-35. "Increased tanker traffic threatens marine fish, invertebrate, and mammal populations by disrupting acoustic signaling used for a variety of processes, including foraging and habitat selection (e.g. Vasconcelos et al. 2007; Rolland et al. 2012), and by physical collision with ships – a large source of mortality for marine animals near the surface along shipping routes (Weir and Pierce 2013)."[263] Acoustic impacts must be evaluated as an environmental impact of the Project. However, in spite of the DEIR's admission that noise impacts would increase for fish and marine mammals under the Project, it still finds only minimal disturbance and concludes that "Behavioral disturbance and physical injury to fish and marine mammals from increasing intermittent vessel noise is not expected to be significant; thus impacts to special status species as a result of noise from increased vessel numbers would be less than significant." DEIR 3.4-35. No further analysis is given. This discrepancy must be explained in the final EIR, and mitigation measures, such as reducing vessel speed and the other potential mitigations must be implemented and incentivized. In addition, the DEIR must require that acoustic safeguards comport with recent scientific guidance for evaluating the risk to marine species.[264]

Oil spill impacts are not adequately evaluated for biological resources and wildlife in the DEIR. The DEIR erroneously assumes that spills feedstocks for biofuels can be treated the same as petroleum-based spills. *See, e.g.*, DEIR 3.4-40 (also relying on the analysis in old DEIRs). There is no evidence that this is the case presented in the DEIR, and there is no evidence that current spill response capabilities are capable of or even authorized to respond to spills of non-petroleum feedstocks.

[262] Green *et al*. 2017.
[263] *Id*.
[264] See Southall et al., Marine Mammal Noise Exposure Criteria: Assessing the Severity of Marine Mammal Behavioral Responses to Human Noise, *Aquatic Mammals*, (2021) 47(5), 421-464.

> Impacts from spills would depend on the material and quantity spilled. The above-referenced EIRs address spills from light oils such as fuel oil, medium oils such as crude oil and heavy oils such as heavy crude and some fuel oils. Biofuels such as ethanol or biodiesel, which are derived from vegetable oils or animal fats, behave differently from conventional petroleum-based fuels in the environment. A discussion of hazards associated with the change of feedstocks is provided in Section 3.9 Hazards and Hazardous Materials.

DEIR 3.4-41. This discussion does not address feedstock differences, and is inadequate to address risks to wildlife. Marathon could do more, for instance to study cleanup methodologies and impacts from spills. The DEIR's proposed mitigation measures are insufficient to address these concerns.

Invasive species are also a dangerous side effect of commercial shipping. "Tankers also serve as a vector for the introduction of non-indigenous species (NIS) via inadvertent transfer of propagules from one port to another (Drake and Lodge 2004), with the probability of introduction depending on the magnitude and origin of shipping traffic along tanker routes (Table 1 and Figure 3; Lawrence and Cordell 2010)." Invasive species impacts must be evaluated as an environmental impact of the Project. "Nonindigenous aquatic species can be introduced into the San Francisco Bay Estuary through ballast water exchange or vessel biofouling." DEIR 3.4-42. Yet the DEIR's mitigation measures are insufficient. Again, sending a flyer does not prevent the problems identified in the DEIR. DEIR 4.4-143. Additional recommended mitigation measures include incentives for ballast water remediation that ensures protection of sensitive areas and requiring documentation of ballast water exchanges from all visiting ships.

In addition, the GHG emissions from the Project will contribute to climate change and in turn harm marine species. The combined GHG emissions from the facility, increased vessel traffic, and upstream and downstream emissions will have adverse impacts on marine species through temperature changes and ocean acidification. These changes may trigger changes to population distributions or migration, making ship strikes in some areas more likely.[265]

G. Noise and Vibration Impact Analysis is Insufficient

According to the DEIR, "[t]he Project would not result in an increased number of vessels calling at the Marine Terminal on a peak day. Accordingly, noise levels would not increase as a result of peak-day vessel activity." DEIR 4.12-396. Furthermore, the DEIR's analysis of noise impacts completely neglects to address noise from ship traffic. DEIR § 3.12. This analysis is insufficient. The DEIR admits that overall vessel trips will drastically increase, but no analysis is made of what noise impacts will result from the increased number of vessels. The final EIR must evaluate noise impacts associated with the increase in vessel trips.

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[265] See Redfern et al., Effects of Variability in Ship Traffic and Whale Distributions on the Risk of Ships Striking Whales, *Frontiers in Marine Science* (Feb. 2020) Vol. 6, art. 793.

H. Transportation and Traffic Impacts Analysis is Inadequate

Additional impacts must be analyzed starting at the port that ships associated with the Project take on their cargos and ending at the ports they discharge it to. The EIR should include shipping impacts to public or non-Project commercial vessels and businesses, including impacts to recreational boaters and ferries, that might experience increased delay, anchorage waits or related crowding, and increased navigational complexity. Collision and spill analysis should not be limited to just the vessels calling at the marine terminal associated with the Project: increased ship traffic could result in accidents among other ships or waterborne vessels. This likelihood must be analyzed in the final EIR, just as vehicular traffic increases are analyzed for their impact on overall accident rates and traffic, generally. Such shipping traffic impact evaluations should extend to spills, air quality, marine life impacts from ship collisions, and other environmental impacts evaluated by the DEIR that could impact shipping traffic.

I. Tribal Cultural Resources Impacts Analysis is Inadequate

The only tribal cultural impacts examined by the DEIR are construction impacts. But many of the people who historically called this area home had an intimate relationship with the Bay and the water, so impacts from increased marine terminal use and increased shipping traffic, as well as associated increased spill risk and impacts to fish and wildlife, must be examined in the final EIR as well. Examples of tribes that should be consulted include the Me-Wuk (Coast Miwok), the Karkin, the Me-Wuk (Bay Miwok), the Confederated Villages of Lisjan, Graton Rancheria, the Muwekma, the Ramaytush, and the Ohlone.

J. The Project Risks Significant Environmental Justice and Economic Impacts

To the extent the Project utilizes offsets or credits, these have an undue impact on disadvantaged and already polluted communities, and the environmental justice impacts of such use must be evaluated. Violations, such as the air quality violations referenced above, also have an undue impact on disadvantaged and already polluted communities, impacts that cannot be addressed through monetary penalties.

Martinez has a high concentration of hazardous waste facilities, has a high concentration of contamination from Toxic Release Inventory chemicals. This area also suffers from high levels of health impacts.

Fisheries would also be a major casualty of any large spill, and struggling fishing communities would be hardest hit by such impacts. Dungeness crab landings, for instance, were 3.1 million pounds in 2015, down almost 83% from the year before, with Oregon landings down a similar percentage.[266] Additional stress on these fisheries as a result of a spill or from other impacts from increased tanker traffic could have catastrophic consequences that need to be examined in the final EIR. Overall, California produced 366 million pounds of fish worth 252.6 million dollars in 2014 and 195 million pounds of fish worth 143.1 million dollars in 2015, and threats to this industry that result from the Project must be evaluated in the EIR.

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[266] *See* 2015 NOAA Fisheries of the United States.

K. The DEIR Fails to Disclose and Analyze Significant Additional Impacts

1. Public Trust Resources

The marine terminals that the Project targets for increased ship traffic occupies leased land, filled and unfilled. This land is California-owned sovereign land, and as a result the California State Lands Commission is a responsible party. Public trust impacts to this land and to other public trust resources must be evaluated in the final EIR.

2. Cross-Border Impacts

Shipping and ship traffic impacts extend across state and national borders. The final EIR must take into account environmental impacts that occur outside of California as a result of actions within California.

3. Terrorism Impacts

More ships bring increased risk. Anti-terrorism and security measures, as well as the potential impacts from a terrorist or other non-accidental action, must be evaluated in the final EIR.

XII. CONCLUSION

We request that the County address and correct the errors and deficiencies in the DEIR explained in this Comment. Given the extensive additional information that needs to be provided in an EIR to satisfy the requirements of CEQA, we request that the new information be included in a recirculated DEIR to ensure that members of the public have full opportunity to comment on it.

Thank you for your consideration of these Comments.

Very truly yours,

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APPENDIX A

Karras, G., *Changing Hydrocarbons Midstream* (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 www.energy-re-source.com

August 2021

ABSTRACT

Moves to deoxygenate farmed lipids with hydrogen by repurposing troubled crude refining assets for "drop in" biofuels add a new carbon source to the liquid hydrocarbon fuel chain, with the largest biorefineries of this type that the world has ever seen now proposed in California. Characteristics of this particular biofuel technology were assessed across its shared fuel chain with petroleum for path-dependent feedstock acquisition, processing, fuel mix, and energy system effects on the environment at this newly proposed scale. The analysis was grounded by site-specific data in California.

This work found significant potential impacts are foreseeable. Overcommitment to purpose-grown biomass imports could shift emissions out of state instead of sequestering carbon. Fossil fuel assets repurposed for hydrogen-intensive deoxygenation could make this type of biorefining more carbon intensive than crude refining, and could worsen refinery fire, explosion, and flaring hazards. Locked into making distillate fuels, this technology would lock in diesel and compete with zero-emission freight and shipping for market share and hydrogen. That path-dependent impact could amplify, as electric cars replace gasoline and idled crude refining assets repurpose for more biomass carbon, to turn the path of energy transition away from climate stabilization. Crucially, this work also found that a structural disruption in the liquid hydrocarbon fuel chain opened a window for another path, to replace the freight and shipping energy function of crude refining without risking these impacts. The type and use of hydrogen production chosen will be pivotal in this choice among paths to different futures.

ACRONYMS AND TERMS

Barrel (b):	A barrel of oil is a volume of 42 U.S. gallons.
BEV:	Battery-electric vehicle.
Biofuel:	Hydrocarbons derived from biomass and burned for energy.
Biomass:	Any organic material that is available on a recurring basis, excluding fossil fuels.
Carbon intensity:	The amount of climate emission caused by a given amount of activity at a particular emission source. Herein, CO_2 or CO_2e mass per barrel refined, or SCF hydrogen produced.
Carbon lock-in:	Resistance to change of carbon-emitting systems that is caused by mutually reinforcing technological, capital, institutional, and social commitments to the polluting system which have become entrenched as it was developed and used. A type of path dependance.
Catalyst:	A substance that facilitates a chemical reaction without being consumed in the reaction.
Ester:	A molecule or functional group derived by condensation of an alcohol and an acid with simultaneous loss of water. Oxygen, carbon, and other elements are bonded together in esters.
Electrolysis:	Chemical decomposition produced by passing an electric current through a liquid or solution containing ions. Electrolysis of water produces hydrogen and oxygen.
FCEV:	Fuel cell electric vehicle.
HDO:	Hydrodeoxygenation. Reactions that occur in HEFA processing.
HEFA:	Hydrotreating esters and fatty acids. A biofuel production technology.
Hydrocarbon:	A compound of hydrogen and carbon.
Lipids:	Organic compounds that are oily to the touch and insoluble in water, such as fatty acids, oils, waxes, sterols, and triacylglycerols (TAGS). Fatty acids derived from TAGs are the lipid-rich feedstock for HEFA biofuel production.
MPC:	Marathon Petroleum Corporation, headquartered in Findlay, OH.
P66:	Phillips 66 Company, headquartered in Houston, TX.
SCF:	Standard cubic foot. 1 ft^3 of gas that is not compressed or chilled.
TAG:	Triacylglycerol. Also commonly known as triglyceride.
Ton (t):	Metric ton.
ZEV:	Zero-emission vehicle.

CONTENTS

FINDINGS AND TAKEAWAYS

Finding 1. Oil companies are moving to repurpose stranded and troubled petroleum assets using technology called "Hydrotreated Esters and Fatty Acids" (HEFA), which converts vegetable oil and animal fat lipids into biofuels that refiners would sell for combustion in diesel engines and jet turbines. The largest HEFA refineries to be proposed or built worldwide to date are now proposed in California.

Takeaways

F1.1 Prioritizing industry asset protection interests ahead of public interests could lock in HEFA biofuels instead of cleaner alternatives to petroleum diesel and jet fuel.

F1.2 HEFA refining could continue to expand as refiners repurpose additional crude refining assets that more efficient electric cars will idle by replacing gasoline.

F1.3 Assessment of potential impacts across the HEFA fuel chain is warranted before locking this new source of carbon into a combustion-based transportation system.

Finding 2. Repurposing refining assets for HEFA biofuels could increase refinery explosion and fire hazards. Switching from near-zero oxygen crude to 11 percent oxygen biomass feeds would create new damage mechanisms and intensify hydrogen-driven exothermic reaction hazards that lead to runaway reactions in biorefinery hydro-conversion reactors. These hydrogen-related hazards cause frequent safety incidents and even when safeguards are applied, recurrent catastrophic explosions and fires, during petroleum refining. At least 100 significant flaring incidents traced to these hazards occurred since 2010 among the two refineries where the largest crude-to-biofuel conversions are now proposed. Catastrophic consequences of the new biorefining hazards are foreseeable.

Takeaways

F2.1 Before considering public approvals of HEFA projects, adequate reviews will need to report site-specific process hazard data, including pre-project and post-project equipment design and operating data specifications and parameters, process hazard analysis, hazards, potential safeguards, and inherent safety measures for each hazard identified.

F2.2 County and state officials responsible for industrial process safety management and hazard prevention will need to ensure that safety and hazard prevention requirements applied to petroleum refineries apply to converted HEFA refineries.

Finding 3. Flaring by the repurposed biorefineries would result in acute exposures to episodic air pollution in nearby communities. The frequency of these recurrent acute exposures could increase due to the new and intensified process safety hazards inherent in deoxygenating the new biomass feeds. Site-specific data suggest bimonthly acute exposure recurrence rates for flare incidents that exceed established environmental significance thresholds. This flaring would result in prolonged and worsened environmental justice impacts in disparately exposed local communities that are disproportionately Black, Brown, or low-income compared with the average statewide demographics.

Takeaways

F3.1 Before considering public approvals of HEFA projects, adequate reviews will require complete analyses of potential community-level episodic air pollution exposures and prevention measures. Complete analyses must include worst-case exposure frequency and magnitude with impact demographics, apply results of process hazard, safeguard, and inherent safety measures analysis (F2.1), and identify measures to prevent and eliminate flare incident exposures.

F3.2 The Bay Area, San Joaquin Valley, and South Coast air quality management districts will need to ensure that flare emission monitoring and flaring prevention requirements applied to petroleum refineries apply to converted HEFA refineries.

Finding 4. Rather than contributing to a reduction in emissions globally, HEFA biofuels expansion in California could actually shift emissions to other states and nations by reducing the availability of limited HEFA biofuels feedstock elsewhere. Proposed HEFA refining for biofuels in California would exceed the per capita state share of total U.S. farm yield for all uses of lipids now tapped for biofuels by 260 percent in 2025. Foreseeable further HEFA growth here could exceed that share by as much as 660 percent in 2050. These impacts are uniquely likely and pronounced for the type of biomass HEFA technology demands.

Takeaways

F4.1 A cap on in-state use of lipids-derived biofuel feedstocks will be necessary to safeguard against these volume-driven impacts. *See also Takeaway F6.1.*

F4.2 Before considering public approvals of HEFA projects, adequate reviews will need to fully assess biomass feedstock extraction risks to food security, low-income families, future global farm yields, forests and other natural carbon sinks, biodiversity, human health, and human rights using a holistic and precautionary approach to serious and irreversible risks.

F4.3 This volume-driven effect does not implicate the Low Carbon Fuel Standard and can only be addressed effectively via separate policy or investment actions.

Changing Hydrocarbons Midstream

Finding 5. Converting crude refineries to HEFA refineries would increase the carbon intensity of hydrocarbon fuels processing to 180–240 percent of the average crude refinery carbon intensity nationwide. Refiners would cause this impact by repurposing otherwise stranded assets that demand more hydrogen to deoxygenate the type of biomass the existing equipment can process, and supply that hydrogen by emitting some ten tons of carbon dioxide per ton of hydrogen produced. In a plausible HEFA growth scenario, cumulative CO_2 emissions from continued use of existing California refinery hydrogen plants alone could reach 300–400 million metric tons through 2050.

Takeaways

F5.1 Before considering public approvals of HEFA projects, adequate reviews will need to complete comprehensive biorefinery potential to emit estimates based on site-specific data, including project design specifications, engineering for renewable-powered electrolysis hydrogen capacity at the site, and potential to emit estimates with and without that alternative. *See also Takeaways F7.1–4.*

Finding 6. HEFA biofuels expansion that could be driven by refiner incentives to repurpose otherwise stranded assets is likely to interfere with state climate protection efforts, in the absence of new policy intervention. Proposed HEFA plans would exceed the lipids biofuel caps assumed in state climate pathways through 2045 by 2025. Foreseeable further HEFA biofuels expansion could exceed the maximum liquid hydrocarbon fuels volume that can be burned in state climate pathways, and exceed the state climate target for emissions in 2050.

Takeaways

F6.1 A cap on lipids-derived biofuels will be necessary to safeguard against these HEFA fuel volume-driven impacts. *See also Takeaway F4.1.*

F6.2 Oil company incentives to protect refining and liquid fuel distribution assets suggest HEFA biofuels may become locked-in, rather than transitional, fuels.

F6.3 A cap on HEFA biofuels would be consistent with the analysis and assumptions in state climate pathways.

Finding 7. A clean hydrogen alternative could prevent emissions, spur the growth of zero-emission fuel cell vehicle alternatives to biofuels, and ease transition impacts.

Early deployment of renewable-powered electrolysis hydrogen production at California crude refineries during planned maintenance or HEFA repurposing could prevent 300–400 million metric tons of CO_2 emissions through 2050 and support critically needed early deployment of energy integration measures for achieving zero emission electricity and heavy-duty vehicle fleets.

Moreover, since zero-emission hydrogen production would continue on site for these zero-emission energy needs, this measure would lessen local transition impacts on workers and communities when refineries decommission.

Takeaways

F7.1 This feasible measure would convert 99 percent of current statewide hydrogen production from carbon-intensive steam reforming to zero-emission electrolysis. This clean hydrogen, when used for renewable grid balancing and fuel cell electric vehicles, would reap efficiency savings across the energy system.

F7.2 Early deployment of the alternatives this measure could support is crucial during the window of opportunity to break free from carbon lock-in which opened with the beginning of petroleum asset stranding in California last year and could close if refiner plans to repurpose those assets re-entrench liquid combustion fuels.

F7.3 During the crucial early deployment period, when fuel cell trucks and renewable energy storage could be locked out from use of this zero-emission hydrogen by excessive HEFA growth, coupling this electrolysis measure with a HEFA biofuel cap (*F4.1; F6.1*) would greatly increase its effectiveness.

F7.4 Coupling the electrolysis and HEFA cap measures also reduces HEFA refinery hazard, localized episodic air pollution and environmental justice impacts.

F7.5 The hydrogen roadmap in state climate pathways includes converting refineries to renewable hydrogen, and this measure would accelerate the deployment timeline for converting refinery steam reforming to electrolysis hydrogen production.

INTRODUCTION

i.1 Biofuels in energy systems

Fossil fuels redefined the human energy system. Before electric lights, before gaslights, whale oil fueled our lanterns. Long before whaling, burning wood for light and heat had been standard practice for millennia. Early humans would learn which woods burned longer, which burned smokier, which were best for light, and which for heat. Since the first fires, we have collectively decided on which biofuel carbon to burn, and how much of it to use, for energy.

We are, once again, at such a collective decision point. Biofuels—hydrocarbons derived from biomass and burned for energy—seem, on the surface, an attractive alternative to crude oil. However, there are different types of biofuels and ways to derive them, each carrying with it different environmental impacts and implications. Burning the right type of biofuel for the right use *instead* of fossil fuels, such as cellulose residue-derived instead of petroleum-derived diesel for old trucks until new zero emission hydrogen-fueled trucks replace them, might help to avoid severe climate and energy transition impacts. However, using more biofuel burns more carbon. Burning the wrong biofuel *along with* fossil fuels can increase emissions—and further entrench combustion fuel infrastructure that otherwise would be replaced with cleaner alternatives.

i.1.1 Some different types of biofuel technologies

Corn ethanol

Starch milled from corn is fermented to produce an alcohol that is blended into gasoline. Ethanol is about 10% of the reformulated gasoline sold and burned in California.

Fischer-Tropsch synthesis

This technology condenses a gasified mixture of carbon monoxide and hydrogen to form hydrocarbons and water, and can produce synthetic biogas, gasoline, jet fuel, or diesel biofuels. A wide range of materials can be gasified for this technology. Fischer-Tropsch synthesis can make any or all of these biofuels from cellulosic biomass such as cornstalk or sawmill residues.

Biofuel in the Climate System 101

People and other animals exhale carbon dioxide into the air while plants take carbon dioxide out of the air. Biofuel piggybacks on—and alters—this natural carbon cycle. It is fuel made to be burned but made from plants or animals that ate plants. Biofuels promise to let us keep burning fuels for energy by putting the carbon that emits back into the plants we will make into the fuels we will burn next year. All we have to do is grow a lot of extra plants, and keep growing them.

But can the biofuel industry keep that promise?

This much is clear: burning biofuels emits carbon and other harmful pollutants from the refinery stack and the tailpipe. Less clear is how many extra plants we can grow; how much land for food, natural ecosystems and the carbon sinks they provide it could take; and ultimately, how much fuel combustion emissions the Earth can take back out of the air.

Some types of biofuels emit more carbon than the petroleum fuels they replace, raise food prices, displace indigenous peoples, and worsen deforestation. Other types of biofuels might help, along with more efficient and cleaner renewable energy and energy conservation, to solve our climate crisis.

How much of which types of biofuels we choose matters.

"Biodiesel"

Oxygen-laden hydrocarbons made from lipids that can only be burned along with petroleum diesel is called "biodiesel" to denote that limitation, which does not apply to all diesel biofuels.

Hydrotreating esters and fatty acids (HEFA)

HEFA technology produces hydrocarbon fuels from lipids. This is the technology crude refiners propose to use for biofuels. The diesel hydrocarbons it produces are different from "biodiesel" and are made differently, as summarized directly below.

i.2 What is HEFA technology?

i.2.1 <u>How HEFA works</u>

HEFA removes oxygen from lipidic (oily) biomass and reformulates the hydrocarbons this produces so that they will burn like certain petroleum fuels. Some of the steps in HEFA refining are similar to those in traditional petroleum refining, but the "deoxygenation" step is very different, and that is because lipids biomass is different from crude and its derivatives.

i.2.2 <u>HEFA feedstocks</u>

Feedstocks are detailed in Chapter 2. Generally, all types of biomass feedstocks that HEFA technology can use contain lipids, which contain oxygen, and nearly all of them used for HEFA biofuel today come directly or indirectly from one (or two) types of farming.

Purpose-grown crops

Vegetable oils from oil crops, such as soybeans, canola, corn, oil palm, and others, are used directly and indirectly as HEFA feedstock. Direct use of crop oils, especially soy, is the major portion of total HEFA feeds. Indirect uses are explained below. Importantly, these crops were cultivated for food and other purposes which HEFA biofuels now compete with—and a new oil crop that has no existing use can still compete for farmland to grow it. Some other biofuels, such as those which can use cellulosic residues as feedstock for example, do not raise the same issue. Thus, in biofuels jargon, the term "purpose-grown crops" denotes this difference among biofuels.

Animal fats

Rendered livestock fats such as beef tallow, pork lard, and chicken fat are the second largest portion of the lipids in HEFA feedstock, although that might change in the future if refiners tap fish oils in much larger amounts. These existing lipid sources also have existing uses for food and other needs, many of which are interchangeable among the vegetable and animal lipids. Also, particularly in the U.S. and similar agricultural economies, the use of soy, corn and other crops as livestock feeds make purpose-grown crops the original source of these HEFA feeds.

Used cooking oils

Used cooking oil (UCO), also called yellow grease or "waste" oil, is a variable mixture of used plant oils and animal fats, typically collected from restaurants and industrial kitchens. It notably could include palm oil imported and cooked by those industries. HEFA feeds include UCO, though its supply is much smaller than those of crop oils or livestock fats. UCO, however, originates from the same purpose grown oil crops and livestock, and UCO has other uses, many of which are interchangeable with the other lipids, so it is not truly a "waste" oil.

i.2.3 HEFA processing chemistry

The HEFA process reacts lipids biomass feedstock with hydrogen over a catalyst at high temperatures and pressures to form hydrocarbons and water. The intended reactions of this "hydro-conversion" accomplish the deoxygenation and reformulation steps noted above.

The role of hydrogen in HEFA production

Hydrogen is consumed in several HEFA process reactions, especially deoxygenation, which removes oxygen from the HEFA process hydrocarbons by bonding with hydrogen to form water. Hydrogen also is essential for HEFA process reaction control. As a result, HEFA processing requires vast amounts of hydrogen, which HEFA refineries must produce in vast amounts. HEFA hydro-conversion and hydrogen reaction chemistry are detailed in Chapter 1.

i.2.4 What HEFA produces

"Drop in" diesel

One major end product of HEFA processing is a "drop-in" diesel that can be directly substituted for petroleum diesel as some, or all, of the diesel blend fueled and burned. Drop-in diesel is distinct from biodiesel, which must be blended with petroleum diesel to function in combustion engines and generally needs to be stored and transported separately. Drop-in diesel is also referred to as "renewable" diesel, however, those labels also apply to diesel made by other biofuel technologies, so diesel produced by the HEFA process is called "HEFA diesel" herein.

"Sustainable Aviation Fuel"

The other major end product of HEFA processing is a partial substitute for petroleum-based jet fuel, sometimes referred to as "Sustainable Aviation Fuel" or "SAF," which also is produced by other biofuel technologies. HEFA jet fuel is allowed by aviation standards to be up to a maximum of 50% of the jet fuel burned, so it must be blended with petroleum jet fuel.

i.3 Conversions of Crude oil refineries to HEFA

i.3.1 Current and proposed conversions of oil refineries

Phillips 66 Co. (P66) proposes to convert its petroleum refinery in Rodeo, CA into a 80,000 barrel per day (b/d) biorefinery.[2] In nearby Martinez, Marathon Petroleum Corporation (MPC) proposes a 48,000 b/d biorefinery[3] at the site where it closed a crude refinery in April 2020.[4] Other crude-to-biofuel refinery conversions are proposed or being built in Paramount, CA (21,500 b/d new capacity),[5] Bakersfield, CA (15,000 b/d),[6] Port Arthur, TX (30,700 b/d),[7] Norco, LA (17,900 b/d new capacity),[8] and elsewhere. All of these projects are super-sized compared with the 2,000–6,000 b/d projects studied as of just a few years ago.[9] The P66 Rodeo and MPC Martinez projects are the largest of their kind to be proposed or built to date. P66 boasts that its Rodeo biorefinery would be the largest in the world.[10]

i.3.2 Repurposing of existing equipment

Remarkably, all of the crude-to-biofuel conversion projects listed above seek to use HEFA technology—none of the refiners chose Fischer-Tropsch synthesis despite its greater flexibility than HEFA technology and ability to avoid purpose-grown biomass feedstock. However, this is consistent with repurposing the plants already built. The California refiners propose to repurpose existing hydro-conversion reactors—hydrocrackers or hydrotreaters—for HEFA processing, and existing hydrogen plants to supply HEFA process hydrogen needs.[2–6] Moreover, it is consistent with protecting otherwise stranded assets; repurposed P66 and MPC assets have recently been shut down, are being shut down, or will potentially be unusable soon, as described in Chapter 1.

While understandable, this reaction to present and impending petroleum asset stranding appears to be driving our energy system toward HEFA technology instead of potentially cleaner alternatives at an enormous scale, totaling 164,500 b/d by 2024 as proposed now in California. This assets protection reaction also presents a clear potential for further HEFA expansion. Refiners could continue to repurpose petroleum refining assets which will be idled as by the replacement of gasoline with more efficient electric passenger vehicles.

Before allowing this new source of carbon to become locked into a future combustion-based transportation system, assessment of potential impacts across the HEFA fuel chain is warranted.

i.4 Key questions and concerns about crude-to-biofuel conversions

i.4.1 Potential impacts of biomass feedstock acquisition

Proposed and potential HEFA expansions in California would rapidly and substantially increase total demand for globally traded agricultural lipids production. This could worsen food insecurity, risk deforestation, biodiversity and natural carbon sink impacts from expansions of farm and pasture lands, and drive populations elsewhere to prioritize use of their remaining lipids shares for food. Biofuel, biodiversity, and climate analysts often refer to the food security impact and agriculture expansion risks in terms of food price and "indirect land use" impacts. The latter effect, on *where* a globally limited biofuel resource could be used, is often referred to by climate policy analysts as an emission-shifting or "leakage" impact. Chapter 2 reviews these potential feedstock acquisition impacts and risks.

i.4.2 Potential impacts of HEFA refinery processing

Processing a different oil feedstock is known to affect refinery hazards and emissions, and converted HEFA refineries would process a very different type of oil feedstock. The carbon intensity—emissions per barrel processed—of refining could increase because processing high-oxygen plant oils and animal fats would consume more hydrogen, and the steam reformers that refiners plan to repurpose emit some ten tons of CO_2 per ton of hydrogen produced. Explosion and fire risks could increase because byproducts of refining the new feeds pose new equipment damage hazards, and the extra hydrogen reacted with HEFA feeds would increase the frequency and magnitude of dangerous runaway reactions in high-pressure HEFA reactors. Episodic air pollution incidents could recur more frequently because refiners would partially mitigate the impacts of those hazards by rapid depressurization of HEFA reactor contents to refinery flares, resulting in acute air pollutant exposures locally. Chapter 3 assesses these potential impacts.

i.4.3 Potential impacts on climate protection pathways

A climate pathway is a road map for an array of decarbonization technologies and measures to be deployed over time. California has developed a range of potential pathways to achieve its climate goals—all of which rely on replacing most uses of petroleum with zero-emission battery-electric vehicles and fuel cell-electric vehicles (FCEVs) energized by renewable electricity. Proposed and potential HEFA biofuels growth could exceed this range of state pathways or interfere with them in several ways that raise serious questions for our future climate.

HEFA biofuels could further expand as refiners repurpose assets idled by the replacement of gasoline with electric vehicles. This could exceed HEFA caps *and* total liquid fuels volumes in the state climate pathways. Hydrogen committed to HEFA growth would not be available for FCEVs and grid-balancing energy storage, potentially slowing zero-emission fuels growth. High-carbon hydrogen repurposed for HEFA refining, which could not pivot to zero-emission FCEV fueling or energy storage, could lock in HEFA biofuels instead of supporting transitions to cleaner fuels. These critical-path climate factors are assessed in Chapter 4.

i.4.4 Alternatives, opportunities and choices

Zero emission hydrogen alternative

Renewable-powered electrolysis of water produces zero-emission hydrogen that could replace existing high-carbon hydrogen production during refinery maintenance shutdowns and HEFA conversions. Indeed, a "Hydrogen Roadmap" in state climate pathways envisions converting all refineries to renewable hydrogen. This measure could cut emissions, support the growth of FCEVs and grid-balancing energy needed to further expand renewable electricity and zero-emission fuels, and reduce local transition impacts when refineries decommission.

Window of opportunity

A crucial window of opportunity to break out of carbon lock-in has opened with the beginning of California petroleum asset stranding in 2020 and could close if refiner plans to repurpose those assets re-entrench liquid combustion fuels. The opening of this time-sensitive window underscores the urgency of early deployment for FCEV, energy storage, and zero-emission fuels which renewable-powered electrolysis could support.

Potential synergies with HEFA biofuels cap

Coupling this measure with a HEFA biofuels cap has the potential to enhance its benefits for FCEV and cleaner fuels deployment by limiting the potential for electrolysis hydrogen to instead be committed to HEFA refining during the crucial early deployment period, and has the potential to reduce HEFA refining hazard, episodic air pollution and environmental justice impacts.

i.4.5 A refinery project disclosure question

Readers should note that P66[2] and MPC[11] excluded flares and hydrogen production which would be included in their proposed HEFA projects from emission reviews they assert in support of their air permit applications. To date neither refiner has disclosed whether or not its publicly asserted project emission estimate excludes any flare or hydrogen production plant emissions. However, as shown in Chapter 3, excluding flare emissions, hydrogen production emissions, or both could underestimate project emission impacts significantly.

i.5 The scope and focus of this report

This report addresses the questions and concerns introduced above. Its scope is limited to potential fuel chain and energy system impacts of HEFA technology crude-to-biofuel conversion projects. It focuses on the California setting and, within this setting, the Phillips 66 Co. (P66) Rodeo and Marathon Petroleum Corp. (MPC) Martinez projects. Details of the data and methods supporting original estimates herein are given in a Supporting Material Appendix.[1]

1. OVERVIEW OF HEFA BIOFUEL TECHNOLOGY

All of the full-scale conversions from petroleum refining to biofuel refining proposed or being built in California now seek to use the same type of technology for converting biomass feedstock into fuels: hydrotreating esters and fatty acids (HEFA).[2 3 4 6] "Hydrotreating" signifies a hydro-conversion process: the HEFA process reacts biomass with hydrogen over a catalyst at high temperatures and pressures to form hydrocarbons and water. "Esters and fatty acids" are the type of biomass this hydro-conversion can process: triacylglycerols (TAGs) and the fatty acids derived from TAGs. HEFA feedstock is biomass from the TAGs and fatty acids in plant oils, animal fats, fish oils, used cooking oils, or combinations of these biomass lipids.

This chapter addresses how HEFA biofuel technology functions, which is helpful to assessing its potential impacts in the succeeding chapters, and explores why former and current crude oil refiners choose this technology instead of another available fuels production option.

1.1 HEFA process chemistry

Hydrocarbons formed in this process reflect the length of carbon chains in its feed. Carbon chain lengths of the fatty acids in the TAGs vary by feed source, but in oil crop and livestock fat feeds are predominantly in the range of 14–18 carbons (C14–C18) with the vast majority in the C16–C18 range.[1] Diesel is predominantly a C15–C18 fuel; Jet fuel C8–C16. The fuels HEFA can produce in relevant quantity are thus diesel and jet fuels, with more diesel produced unless more intensive hydrocracking is chosen intentionally to target jet fuel production.

HEFA process reaction chemistry is complex, and in practice involves hard-to-control process conditions and unwanted side-reactions, but its intended reactions proceed roughly in sequence to convert TAGs into distillate and jet fuel hydrocarbons.[12 13 14 15 16 17 18 19 20 21 22] Molecular sites of these reactions in the first step of HEFA processing, hydrodeoxygenation (HDO), are illustrated in Diagram 1 below.

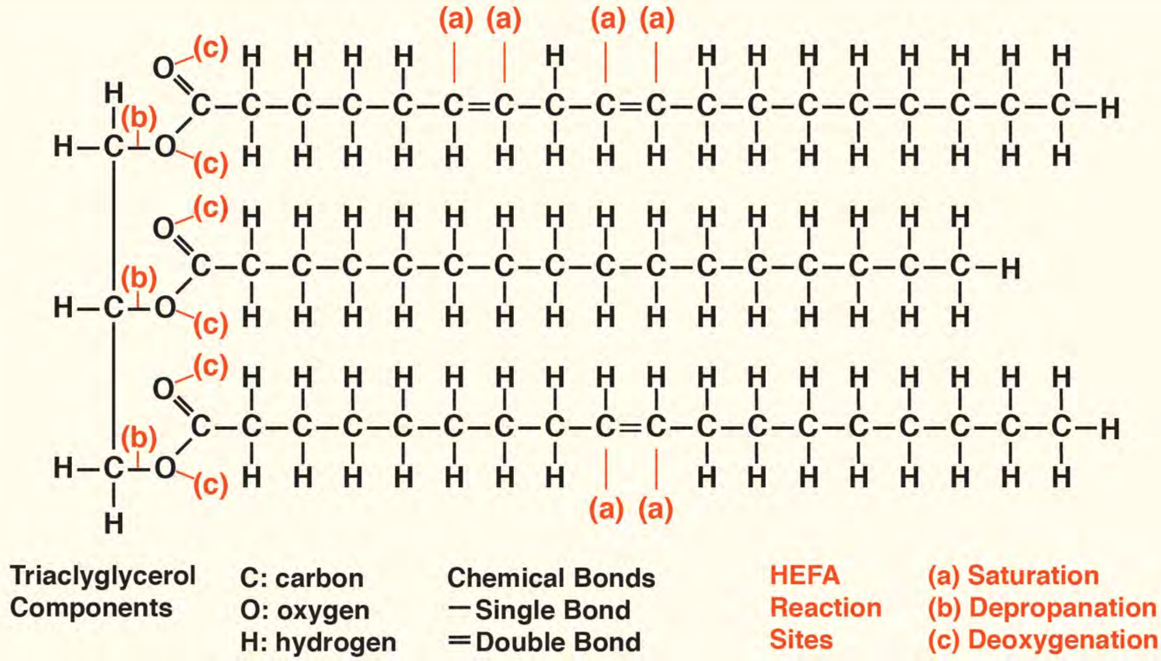


Diagram 1. Hydrodeoxygenation (HDO) of a triacylglycerol (TAG).

Fatty acids are "saturated" by bonding hydrogen to their carbon atoms. *See* (a) in Diagram. This tends to start first. Then, the fatty acids are broken free from the three-carbon "propane knuckle" of the TAG (Diagram 1, left) by breaking its bonds to them via hydrogen insertion. (Depropanation; *see* (b) in Diagram 1.) Still more hydrogen bonds with the oxygen atoms (c), to form water (H_2O), which is removed from the hydrocarbon process stream. These reactions yield water, propane, some unwanted but unavoidable byproducts (not shown in the diagram for simplicity), and the desired HDO reaction products—hydrocarbons which can be made into diesel and jet fuel.

But those hydrocarbons are not yet diesel or jet fuel. Their long, straight chains of saturated carbon make them too waxy. Fueling trucks or jets with wax is risky, and prohibited by fuel specifications. To de-wax them, those straight-chain hydrocarbons are turned into their branched-chain isomers.

Imagine that the second-to-last carbon on the right of the top carbon chain in Diagram 1 takes both hydrogens bonded to it, and moves to in between the carbon immediately to its left and one of the hydrogens that carbon already is bonded to. Now imagine the carbon at the end of the chain moves over to where the second-to-last carbon used to be, and thus stays attached to the carbon chain. That makes the straight chain into its branched isomer. It is isomerization.

Isomerization of long-chain hydrocarbons in the jet–diesel range is the last major HEFA process reaction step. Again, the reaction chemistry is complex, involves hard-to-control process conditions and unwanted side reactions at elevated temperatures and pressures, and uses a lot of hydrogen. But these isomerization reactions, process conditions, and catalysts are markedly different from those of HDO.[9 14–17 19 20] And these reactions, process conditions, catalysts and hydrogen requirements also depend upon whether isomerization is coupled with intentional hydrocracking to target jet instead of diesel fuel production.[1] Thus this last major set of HEFA process reactions has, so far, required a separate second step in HEFA refinery configurations. For example, MPC proposes to isomerize the hydrocarbons from its HDO reactors in a separate second-stage hydrocracking unit to be repurposed from its shuttered Martinez crude refinery.[3]

HEFA isomerization requires very substantial hydrogen inputs, and can recycle most of that hydrogen when targeting diesel production, but consumes much more hydrogen for intentional hydrocracking to boost jet fuel production, adding significantly to the already-huge hydrogen requirements for its HDO reaction step.[1]

The role and impact of heat and pressure in the HEFA process

Hydro-conversion reactions proceed at high temperatures and extremely high pressures. Reactors feeding gas oils and distillates of similar densities to HEFA reactor feeds run at 575–700 ºF and 600–2,000 pounds per square inch (psi) for hydrotreating and at 575–780 ºF and 600–2,800 psi for hydrocracking.[16] That is during normal operation. The reactions are exothermic: they generate heat in the reactor on top of the heat its furnaces send into it. Extraordinary steps to handle the severe process conditions become routine in hydro-conversion. Hydrogen injection and recycle capacities are oversized to quench and attempt to control reactor heat-and-pressure rise.[16 22] When that fails, which happens frequently as shown in a following chapter, the reactors depressurize, dumping their contents to emergency flares. That is during petroleum refining.

Hydro-conversion reaction temperatures increase in proportion to hydrogen consumption,[21] and HDO reactions can consume more hydrogen, so parts of HEFA hydro-conversion trains can run hotter than those of petroleum refineries, form more extreme "hot spots," or both. Indeed, HEFA reactors must be designed to depressurize rapidly.[22] Yet as of this writing, no details of design potential HEFA project temperature and pressure ranges have been reported publicly.

1.2 Available option of repurposing hydrogen equipment drives choice of HEFA

Refiners could choose better new biofuel technology

Other proven technologies promise more flexibility at lower feedstock costs. For example, Fischer-Tropsch synthesis condenses a gasified mixture of carbon monoxide and hydrogen to form hydrocarbons and water, and can produce biogas, gasoline, jet fuel, or diesel biofuels.[23] Cellulosic biomass residues can be gasified for Fischer-Tropsch synthesis.[24] This alternative promises lower cost feedstock than HEFA technology and the flexibility of a wider range of future biofuel sales, along with the same ability to tap "renewable" fuel subsidies as HEFA technology. Refiners choose HEFA technology for a different reason.

Refiners can repurpose existing crude refining equipment for HEFA processing

Hydro-conversion reactors and hydrogen plants which were originally designed, built, and used for petroleum hydrocracking and hydrotreating could be repurposed and used for the new and different HEFA feedstocks and process reactions. This is in fact what the crude-to-biofuel refinery conversion projects propose to do in California.[2 3 5 6]

In the largest HEFA project to be proposed or built, P66 proposes to repurpose its 69,000 barrel/day hydrocracking capacity at units 240 and 246 combined, its 16,740 b/d Unit 248 hydrotreater, and its 35,000 b/d Unit 250 hydrotreater for 100% HEFA processing at Rodeo.[2 25] In the second largest project, MPC proposes to repurpose its 40,000 b/d No.2 HDS hydrotreater, 70,000 b/d No. 3 HDS hydrotreater, 37,000 b/d 1st Stage hydrocracker, and its 37,000 b/d 2nd Stage hydrocracker for 100% HEFA processing at Martinez.[3 26]

For hydrogen production to feed the hydro-conversion processing P66 proposes to repurpose 28.5 million standard cubic feet (SCF) per day of existing hydrogen capacity from its Unit 110 and 120 million SCF/d of hydrogen capacity from the Air Liquide Unit 210 at the same P66 Rodeo refinery.[2 25 27] MPC proposes to repurpose its 89 million SCF/d No. 1 Hydrogen Plant along with the 35 million SCF/d Air Products Hydrogen Plant No. 2 at the now-shuttered MPC Martinez refinery.[3 4 11 26]

By converting crude refineries to HEFA biofuel refiners protect otherwise stranded assets

Motivations to protect otherwise stranded refining assets are especially urgent in the two largest crude-to-biofuel refining conversions proposed to date. Uniquely designed and permitted to rely on a landlocked and fast-dwindling crude source already below its capacity, the P66 San Francisco Refinery has begun to shutter its front end in San Luis Obispo County, which makes its unheated pipeline unable to dilute and send viscous San Joaquin Valley crude to Rodeo.[28] This threatens the viability of its Rodeo refining assets—as the company itself has warned.[29] The MPC Martinez refinery was shut down permanently in a refining assets consolidation, possibly accelerated by COVID-19, though the pandemic closed no other California refinery.[30]

The logistics of investment in new and repurposed HEFA refineries as a refining asset protection mechanism leads refiners to repurpose a refining technology that demands hydrogen, then repurpose refinery hydrogen plants that supply hydrogen, then involve other companies in a related sector—such as Air Liquide and Air products—that own otherwise stranded hydrogen assets the refiners propose to repurpose as well.

Refiners also seek substantial public investments in their switch to HEFA biofuels. Tepperman (2020)[31] reports that these subsidies include federal "Blenders Tax" credits, federal "Renewable Identification Number" credits, and state "Low Carbon Fuel Standard" credits that one investment advisor estimated can total \$3.32 per gallon of HEFA diesel sold in California. Krauss (2020)[32] put that total even higher at \$4.00 per gallon. Still more public money could be directed to HEFA jet fuel, depending on the fate of currently proposed federal legislation.[33]

2. UPSTREAM — IMPACT OF FEEDSTOCK CHOICES

The types, amounts, and characteristics of energy feedstocks have repercussions across the energy system and environment. Choosing HEFA technology would lock into place a particular subset of the biomass carbon on our planet for use in energy production. It would further create a need for continued and potentially additional hydrogen use. This chapter evaluates the environmental impacts of feedstock acquisition and feedstock choices in HEFA production.

2.1 Proposed feedstock use by the Phillips 66, Marathon, and other California projects

2.1.1 Biomass volume

The proposed conversions at P66 and MPC, and attendant use of HEFA feedstocks, are very large in scale. P66 boasts that its Rodeo biorefinery would be the largest in the world.[10] The feedstock capacity of its HEFA biorefinery proposed in Rodeo, CA reported by P66 is 80,000 barrels per day (b/d).[2] With a feedstock capacity of 48,000 b/d, the MPC Martinez, CA project could then be the second largest HEFA refinery to be proposed or built worldwide.[3] The World Energy subsidiary, AltAir, expansion in Paramount, CA, which also plans to fully convert a petroleum refinery, would add 21,500 b/d of new HEFA feedstock capacity.[5] And Global Clean Energy Holdings, Inc. plans to convert its petroleum refinery in Bakersfield, CA into a HEFA refinery[6] with at least 15,000 b/d of new capacity. Altogether that totals 164,500 b/d of new HEFA feedstock capacity statewide.

The aggregate proposed new California feedstock demand is some 61–132 *times* the annual feedstock demand for HEFA refining in California from 2016–2019.[34] But at the same time, the proposed new California biofuel feed demand is only ten percent of California refinery demand for crude oil in 2019,[35] the year before COVID-19 forced temporary refining rate cuts.[36] This raises a potential for the new HEFA feed demand from crude-to-biofuel refinery conversions proposed here today to be only the beginning of an exponentially increasing trend.

2.1.2 Biomass type

HEFA technology, proposed at all of the California refineries currently proposing conversion to biofuel production, uses as feedstock triacylglycerols (TAGs) and fatty acids derived from TAGs (Chapter 1). Primary sources of these biomass lipids in concentrations and amounts necessary for HEFA processing are limited to oil crop plants, livestock fats, and fish oils. Existing U.S. biofuels production has tapped soybean oil, distillers corn oil, canola oil, cottonseed oil, beef tallow, pork lard and grease, poultry fats, fish oils from an unreported and likely wide range of species, and used cooking oil—lipids that could be recovered from uses of these primary sources, also known as "yellow grease."[37 38 39]

2.1.3 Other uses for this type of biomass

Importantly, people already use these oils and fats for many other needs, and they are traded globally. Beside our primary use of this type of biomass to feed ourselves directly, we use it to feed livestock in our food system, to feed our pets, and to make soap, wax, lubricants, plastics, cosmetic products, and pharmaceutical products.[40]

2.2 Indirect impacts of feedstock choices

2.2.1 Land use and food system impacts

Growing HEFA biofuel feedstock demand is likely to increase food system prices. Market data show that investors in soybean and tallow futures have bet on this assumption.[41 42 43] This pattern of radically increasing feedstock consumption and the inevitable attendant commodity price increases threatens significant environmental and human consequences, some of which are already emerging even with more modestly increased feedstock consumption at present.

As early as 2008, Searchinger et al.[44] showed that instead of cutting carbon emissions, increased use of biofuel feedstocks and the attendant crop price increases could expand crop land into grasslands and forests, reverse those natural carbon sinks, and cause food-sourced biofuels to emit more carbon than the petroleum fuels they replace. The mechanism for this would be global land use change linked to prices of commodities tapped for both food and fuel.[44]

Refiners say they will not use palm oil, however, that alone does not solve the problem. Sanders et al. (2012)[45] showed that multi-nation demand and price dynamics had linked soy oil, palm oil, food, and biofuel feedstock together as factors in the deforestation of Southeast Asia for palm oil. Santeramo (2017)[46] showed that such demand-driven changes in prices act across the oil crop and animal fat feedstocks for HEFA biofuels in Europe and the U.S. Searle (2017)[47] showed rapeseed (canola) and soy biofuels demand was driving palm oil expansion; palm oil imports increase for other uses of those oils displaced by biofuels demand.

Additionally, The Union of Concerned Scientists (2015),[48] Lenfert et al. (2017),[49] and Nepstad and Shimada (2018)[50] linked soybean oil prices to deforestation for soybean plantations in the Brazilian Amazon and Pantanal. By 2017, some soy and palm oil biofuels were found to emit more carbon than the petroleum fuels they are meant to replace.[47 51] By 2019 the Intergovernmental Science-Policy Platform on Biodiversity and Ecosystem Services (IPBES) warned large industrial biofuel feedstock plantations threaten global biodiversity.[52] By 2021 the Intergovernmental Panel on Climate Change joined the IPBES in this warning.[53] At high yields and prices, up to 79 million acres could shift to energy crops by 2030 in the U.S. alone.[40] And once a biofuel feedstock also used for food is locked in place, the human impacts of limiting land conversion could potentially involve stark social injustices, notably food insecurity and hunger.[44]

Work by many others who are not cited here contributed to better understanding the problem of our growing fuel chain-food chain interaction. Potential biodiversity loss, such as pollinator population declines, further risks our ability to grow food efficiently. Climate heating threatens more frequent crop losses. The exact tipping point, when pushing these limits too hard might turn the natural carbon sinks that biofuels depend upon for climate benefit into global carbon sources, remains unknown.

2.1.2 Impact on climate solutions

Technological, economic, and environmental constraints across the arrays of proven technologies and measures to be deployed for climate stabilization limit biofuels to a targeted role in sectors for which zero-emission fuels are not yet available.[53 54 55 56 57 58 59 60 61] And these technologies and measures require place-based deployment actions understood in a larger global context—actions that must be planned, implemented, and enforced by the political jurisdictions in each geography, but whose effect must be measured on a worldwide scale. California policy makers acted on this fact by expressly defining an in-state emission reduction which results in an emission increase elsewhere as inconsistent with climate protection.[62]

Tapping a biomass resource for biofuel feedstock can only be part of our state or national climate solution if it does not lead to countervailing climate costs elsewhere that wipe out or overtake any purported benefits. Thus, if California takes biomass from another state or nation which that other state or nation needs to cut emissions there, it will violate its own climate policy, and more crucially, burning that biofuel will not cut carbon emissions. Moreover, our climate policy should not come at the cost of severe human and environmental harms that defeat the protective purpose of climate policy.

Use of biofuels as part of climate policy is thus limited by countervailing climate and other impacts. Experts that the state has commissioned for analysis of the technology and economics of paths to climate stabilization suggest that state biofuel use should be limited to the per capita share of sustainable U.S. production of biofuel feedstock.[54 55] Per capita share is a valid benchmark, and is used herein, but it is not necessarily a basis for just, equitable, or effective policy. Per capita, California has riches, agriculture capacity, solar energy potential, and mild winters that populations in poorer, more arid, or more polar and colder places may lack. Accordingly, the per capita benchmark applied in Table 1 below should be interpreted as a conservative (high) estimate of sustainable feedstock for California HEFA refineries.

Table 1. U.S. and California lipid supplies *v.* potential new lipid feedstock demand from crude-to-biofuel refinery conversions now planned in California.

MM t/y: *million metric tons/year*

Lipids supply	U.S. (MM t/y)	U.S. (%)	CA per capita [d] (MM t/y)	CA produced [e] (MM t/y)
Biofuels [a]	4.00	100 %	0.48	0.30
All uses	20.64	100 %	2.48	1.55
Soybean oil [b]	10.69	52 %		
Livestock fats [a]	4.95	24 %		
Corn oil [b]	2.61	13 %		
Waste oil [a]	1.40	7 %		
Canola oil [b]	0.76	4 %		
Cottonseed [b]	0.23	1 %		

Lipids Demand for four proposed CA refineries (MM t/y) [c]	Percentage of U.S. and California supplies for all uses: U.S. total	CA per capita	CA produced
8.91	43 %	359 %	575 %

a. US-produced supply of feedstocks for hydro-processing esters and fatty acids (HEFA) in 2030, estimated in the U.S. Department of Energy *Billion-Ton Update* (2011).[40] Includes total roadside/farm gate yields estimates in the contiguous U.S. for biofuel feedstock consumption, and for all uses of animal fats and waste oil (used cooking oil).
b. U.S. farm yield for all uses of lipids used in part for biofuels during Oct 2016–Sep 2020 from U.S. Department of Agriculture *Oil Crops Data: Yearbook Tables;* tables 5, 20, 26 and 33.[38] *See* also Karras (2021a).[63]
c. From proposed Rodeo,[2] Martinez,[3] Paramount[5] and Bakersfield[6] capacity at a feed specific gravity of 0.914.
d. California per capita share of U.S. totals based on 12 percent of the U.S. population.
e. Calif. produced lipids, after *Billion-Ton Update* by Mahone et al.,[55] with lipids for all uses scaled proportionately.

2.3 Effect of supply limitations on feedstock acquisition impacts

Feeding the proposed new California HEFA refining capacity could take more than 350% of its per capita share from total U.S. farm yield for *all uses* of oil crop and livestock fat lipids that have been tapped for biofuels in much smaller amounts until now. *See* Table 1. The 80,000 b/d (~4.24 MM t/y) P66 Rodeo project[2] alone could exceed this share by ~71%. At 128,000 b/d (~6.79 MM t/y) combined, the P66[2] and Marathon[3] projects together could exceed it by ~174%.

2.3.1 Supply effect on climate solutions

Emission shifting would be the first and most likely impact from this excess taking of a limited resource. The excess used here could not be used elsewhere, and use of the remaining farmed lipids elsewhere almost certainly would prioritize food. Reduced capacity to develop and use this biofuel for replacing petroleum diesel outside the state would shift future emissions.

2.3.2 Supply effect on land use and food systems

Displacement of lipid food resources at this scale would also risk cascading impacts. These food price, food security, and land conversion impacts fuel deforestation and natural carbon sink destruction in the Global South, and appear to have made some HEFA biofuels more carbon-intensive than petroleum due to indirect land use impacts that diminish the carbon storage capacity of lands converted to biofuel plantations, as described above.[41–53]

The severity of these risks to food security, biodiversity, and climate sinks appears uncertain for some of the same reasons that make it dangerous. Both the human factors that drove land use impacts observed in the past[41–53] and the ecological resilience that constrained their severity in the past may not always scale in a linear or predictable fashion, and there is no precedent for the volume of lipid resource displacement for energy now contemplated.

In contrast, the causal trigger for any or all of these potential impacts would be a known, measurable volume of potential lipid biomass feedstock demand. Importantly, this volume-driven effect does not implicate the Low Carbon Fuel Standard and can only be addressed effectively by separate policy or investment actions.

2.3.3 Supply effect on HEFA feedstock choices

Both Marathon and P66 have indicated informally that their preferred feedstocks are used cooking oil "waste" and domestic livestock fats rather than soy and other food crop oils. It is clear, however, that supplies of these feedstocks are entirely insufficient to meet anticipated demand if the two conversions (and the others planned in California) move forward. Table 1 reveals the fallacy of assuming that used "waste" cooking oil or domestic livestock fats could feed the repurposed HEFA refineries, showing that supplies would be inadequate even in an extreme hypothetical scenario wherein biofuel displaces all other uses of these lipids.

As discussed below, these HEFA feedstock availability limitations have fuel chain repercussions for the other critical HEFA process input—hydrogen.

2.4 Impact of biomass feedstock choices on hydrogen inputs

2.4.1 All HEFA feedstocks require substantial hydrogen inputs to convert the triacylglycerols and fatty acids in the lipid feedstock into HEFA biofuels

Hydrogen (H_2) is the most abundant element in diesel and jet fuel hydrocarbons, and all of the lipid feedstocks that HEFA refiners could process need substantial refinery hydrogen inputs. In HEFA refining hydrogen bonds with carbon in lipid feeds to saturate them, to break the fatty acids and propane "knuckle" of those triacylglycerols apart, and—in unavoidable side-reactions or intentionally to make more jet fuel—to break longer carbon chains into shorter carbon chains. (Chapter 1.) Hydrogen added for those purposes stays in the hydrocarbons made into fuels; it is a true HEFA biofuel feedstock.

Hydrogen also bonds with oxygen in the lipids to remove that oxygen from the hydrocarbon fuels as water. *Id.* Forming the water (H_2O) takes two hydrogens per oxygen, and the lipids in HEFA feedstocks have consistently high oxygen content, ranging from 10.8–11.5 weight percent,[1] so this deoxygenation consumes vast amounts of hydrogen. Further, hydrogen is injected in large amounts to support isomerization reactions that turn straight-chain hydrocarbons into branched-chain hydrocarbons. (Chapter 1.) And more hydrogen is injected to quench and control severe processing conditions under which all of these hydro-conversion reactions proceed. *Id.*

2.4.2 Some HEFA feedstocks need more hydrogen for HEFA processing than others

All types of HEFA feeds consume hydrogen in all the ways described above. However, how much is consumed in the first reaction—saturation—depends on the number of carbon double bonds in the fatty acids of the specific lipid feed source. *See* Diagram 1, Chapter 1. That matters because fatty acids in one specific HEFA lipids feed can have more carbon double bonds than fatty acids in another. Charts 1-A through 1–F below illustrate these differences in the fatty acid profiles of different HEFA feeds. The heights of the columns in these charts show the percentages of fatty acids in each feed that have various numbers of carbon double bonds.

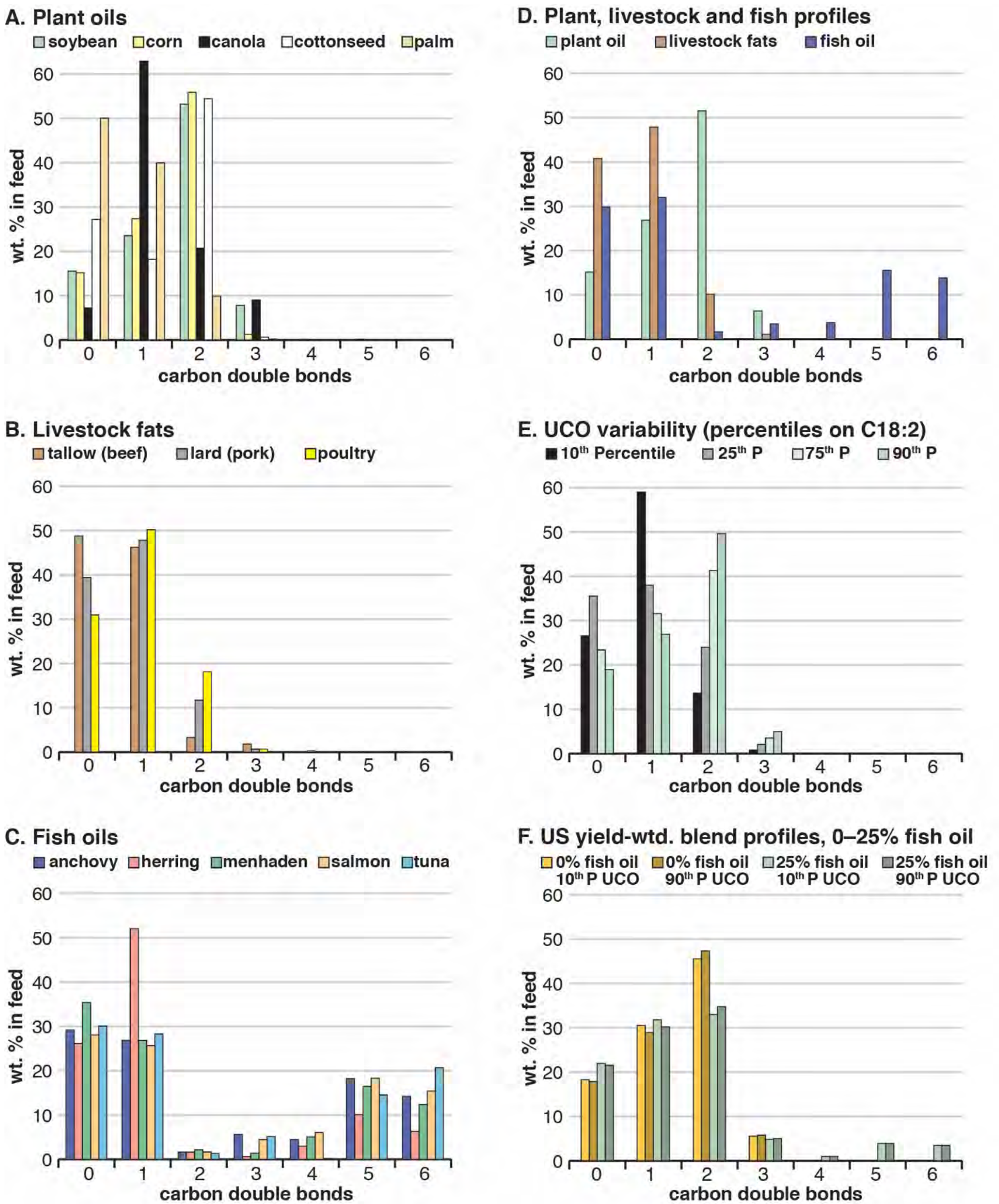
In soybean oil, which accounts for the majority of U.S. oil crops yield shown in Table 1, most of the fatty acids have 2–3 carbon double bonds (Chart 1-A). In contrast, most of the fatty acids in livestock fats have 0–1 carbon double bonds (Chart 1-B). And in contrast to the plant oil *and* livestock fat profiles, which are essentially empty on the right side of charts 1-A and 1-B, a significant portion of the fatty acids in fish oils have 4–6 carbon double bonds (Chart 1-C).

Thus, HEFA processing requires more hydrogen to saturate the carbon double bonds in soy oil than those in livestock fats, and even more hydrogen to saturate those in fish oils. Such single-feed contracts are plausible, but feedstock acquisition logistics for the HEFA biofuels expansion—especially in light of the supply problem shown in Table 1—suggest refiners will process blends, and likely will process yield-weighted blends. Charts 1-D and 1-F show that such blends would dampen but still reflect these differences between specific plant oils, livestock fats, and fish oils. Finally, Chart 1-E illustrates the notoriously variable quality of used cooking oil (UCO), and Chart 1-F illustrates how the impact of UCO variability could be small compared with the differences among other feeds, since UCO could be only a small portion of the blend, as shown in Table 1.

2.4.3 Refining HEFA feedstocks demands more hydrogen than refining crude oil

Table 2, on the next page following the charts below, shows total hydrogen demand per barrel of feedstock, for processing different HEFA feeds, and for targeting different HEFA fuels.

Hydrogen demand for saturation of carbon double bonds ranges across the biomass feeds shown in Table 2 from 186–624 standard cubic feet of H_2 per barrel of biomass feed (SCF/b), and is the largest feedstock-driven cause of HEFA H_2 demand variability. For comparison, total on-purpose hydrogen production for U.S. refining of petroleum crude from 2006–2008, before lighter shale oil flooded refineries, averaged 273 SCF/b.[1 64] This 438 (624-186) SCF/b saturation range alone exceeds 273 SCF/b. The extra H_2 demand for HEFA feeds with more carbon double bonds is one repercussion of the livestock fat and waste oil supply limits revealed in Table 1.



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]

Table 2. Hydrogen demand for processing different HEFA biomass carbon feeds.

Standard cubic feet of hydrogen per barrel of biomass feed (SCF/b)

	Hydrodeoxygenation reactions		Total with isomerization / cracking	
Biomass carbon feed	Saturation [a]	Others [b,c]	Diesel target	Jet fuel target [d]
Plant oils				
Soybean oil	479	1,790	2,270	3,070
Plant oils blend [e]	466	1,790	2,260	3,060
Livestock fats				
Tallow	186	1,720	1,910	2,690
Livestock fats blend [e]	229	1,720	1,950	2,740
Fish oils				
Menhaden	602	1,880	2,480	3,290
Fish oils blend [e]	624	1,840	2,460	3,270
US yield-weighted blends [e]				
Blend without fish oil	438	1,780	2,220	3,020
Blend with 25% fish oil	478	1,790	2,270	3,070

a. Carbon double bond saturation as illustrated in Diagram 1 (a). **b, c.** Depropanation and deoxygenation as illustrated in Diagram 1 (b), (c), and losses to unwanted (diesel target) cracking, off-gassing and solubilization in liquids. **d.** Jet fuel total also includes H_2 consumed by intentional cracking along with isomerization. **e.** Blends as shown in charts 1-D and 1-F. Data from Tables A1and Appendix at A2.[1] Figures may not add due to rounding.

Moreover, although saturation reaction hydrogen alone can exceed crude refining hydrogen, total hydrogen consumption in HEFA feedstock processing is larger still, as shown in Table 2.

Other hydrodeoxygenation reactions—depropanation and deoxygenation—account for most of the total hydrogen demand in HEFA processing. The variability in "other" hydrogen demand mainly reflects unavoidable hydrogen losses noted in Table 2, which rise with hydro-conversion intensity. Targeting maximum jet fuel rather than diesel production boosts total HEFA hydrogen demand by approximately 800 SCF/b.[1 9 65] This is primarily a product slate rather than feed-driven effect: maximizing jet fuel yield from the HDO reaction hydrocarbons output consumes much more hydrogen for intentional hydrocracking, which is avoided in the isomerization of a HEFA product slate targeting diesel.

Total hydrogen demand to process the likely range of yield-weighted biomass blends at the scale of planned HEFA expansion could thus range from 2,220–3,070 SCF/b, fully 8–11 *times* that of the average U.S. petroleum refinery (273 SCF/b).[1 64] This has significant implications for climate and community impacts of HEFA refining given the carbon-intensive and hazardous ways that refiners already make and use hydrogen now.

3. MIDSTREAM — HEFA PROCESS ENVIRONMENTAL IMPACTS

This chapter assesses refinery carbon emissions, refinery explosion and fire hazards, and air pollution impacts from refinery flares in HEFA processing. As shown in Chapter 2, turning a petroleum refinery into a HEFA refinery increases its hydrogen input intensity. This increased hydrogen intensity is particularly problematic given that the proposed conversions are all based on plans to re-purpose existing fossil fuel hydrogen production and hydro-conversion processes (Chapter 1). Current refinery hydrogen production that refiners propose to re-purpose uses the extraordinarily carbon intense "steam reforming" technology. Additionally, refinery explosion, fire, and flare emission hazards associated with processing in hydro-conversion units which refiners propose to re-purpose intensify at the increased hydrogen feed rates HEFA processing requires. P66 proposes to repurpose 148.5 million standard cubic feet per day (MMSCFD) of existing steam reforming hydrogen production capacity and 120,740 barrels per day (b/d) of existing hydro-conversion capacity for its proposed HEFA refinery in Rodeo. *Id.* MPC proposes to repurpose 124 MMSCFD of steam reforming capacity and 147,000 b/d of hydro-conversion capacity for its proposed HEFA refinery in Martinez. *Id.*

3.1 Carbon impact of steam reforming in the HEFA process

The hydrogen intensity of HEFA processing makes emissions from supplying the hydrogen all the more important, and as noted, refiners propose to repurpose carbon-intensive steam reforming. This could boost HEFA refinery carbon emissions dramatically.

Steam reforming makes hydrogen by stripping it from hydrocarbons, and the carbon left over from that forms carbon dioxide (CO_2) that emits as a co-product. See Diagram 2. It is often called methane reforming, but refiners feed it other refining byproduct hydrocarbons along with purchased natural gas, and even more CO_2 forms from the other feeds. The difference illustrated in Diagram 2 comes out to 16.7 grams of CO_2 per SCF of H_2 produced from propane *versus* 13.9 grams CO_2/SCF H_2 produced from methane. Fossil fuel combustion adds more CO_2.

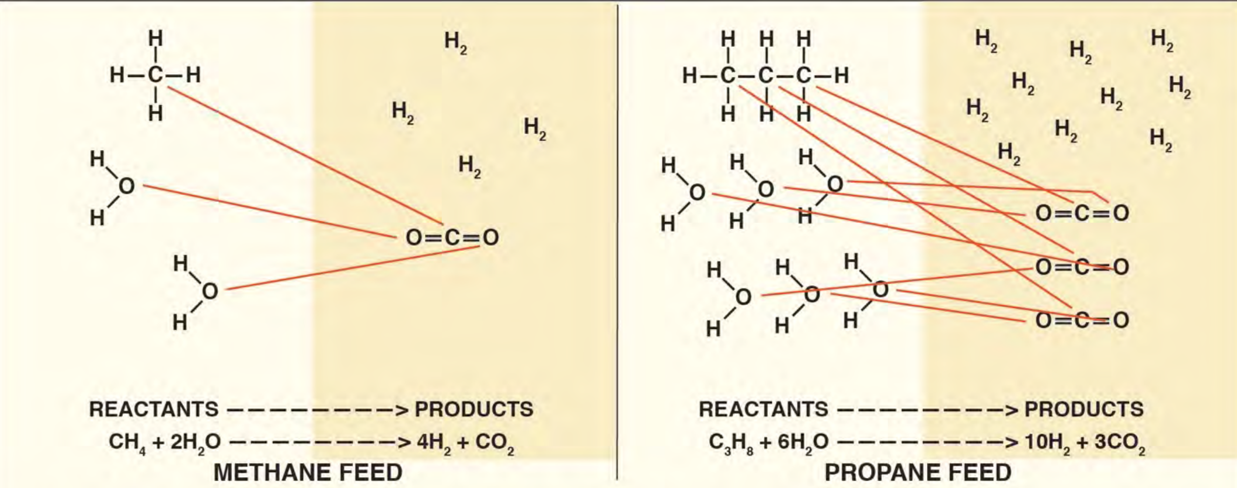


Diagram 2. Hydrogen steam reforming: reforming and shift reactions.
As the reforming and shift reactions produce hydrogen (H_2) from the hydrogen atoms (H) in hydrocarbons and steam, they bond the left-over carbon (C) and oxygen (O) atoms in those reactants together to form carbon dioxide (CO_2). This emits more CO_2 per H_2 produced from hydrocarbons with more carbon atoms.

Heating the water and feed to make the mixture of superheated steam and hydrocarbons that react at 1,300–1,900 ºF, and making the additional steam and power that drive its pumps and pressure, make steam reforming energy intensive. Natural gas and refinery process off gas burn for that energy. Combustion energy intensity, based on design capacities verified and permitted by local air officials, ranges across 11 hydrogen plants that serve or served Bay Area refineries, from 0.142–0.277 million joules (MJ) per SCF H_2 produced, with a median of 0.202 MJ/SCF across the 11 plants.[1] At the median, ~10 gCO_2/SCF H_2 produced emits from burning methane. That, plus the 13.9 g/SCF H_2 from methane feed, could emit 23.9 g/SCF. This median energy intensity (EI) for methane feed is one of the potential plant factors shown in Table 3 below.

Hydrogen plant factors are shown in Table 3 for two feeds—methane, and a 77%/23% methane/propane mix—and for two combustion energy intensities, a Site EI and the median EI from Bay Area data discussed above. The mixed feed reflects propane by-production in HEFA process reactions and the likelihood that this and other byproduct gases would be used as feed, fuel, or both. Site EI should be more representative of actual P66 and MPC plant factors, but details of how they will repurpose those plants have not yet been disclosed. Median EI provides a reference point for P66 and MPC plant factors, and is applied to the other projects in the statewide total at the bottom of the table.

Table 3 shows how high-carbon hydrogen technology and high hydrogen demand for hydro-conversion of HEFA feeds (Chapter 2) combine to drive the carbon intensity of HEFA refining. At the likely hydrogen feed mix and biomass feed blend lower bound targeting diesel production, HEFA hydrogen plants could emit 55.3–57.9 kilograms of CO_2 per barrel of biomass feed. And in those conditions at the upper bound, targeting jet fuel, they could emit 76.4–80.1 kg/b.

Table 3. CO_2 emissions from hydrogen production proposed for HEFA processing by full scale crude-to-biofuel refinery conversions planned in California.

g: gram (CO_2) **SCF:** standard cubic foot (H_2) **b:** barrel (biomass feed) **Mt:** million metric tons

	Plant factor[a] (g/SCF)	Conversion demand (SCF/b)[b]		Carbon intensity (kg/b)	Mass emission[c] (Mt/y)
		Lower bound	Upper bound		
P66 Rodeo					
Mixed feed [d]					
Site EI [a]	26.1	2,220	3,070	57.9 – 80.1	1.69 – 2.34
Median EI [a]	24.9	2,220	3,070	55.3 – 76.4	1.61 – 2.23
Methane [d]					
Site EI [a]	25.0	2,220	3,070	55.5 – 76.7	1.62 – 2.24
Median EI [a]	23.9	2,220	3,070	53.1 – 73.4	1.55 – 2.14
MPC Martinez					
Mixed feed [d]					
Site EI [a]	25.8	2,220	3,070	57.3 – 79.2	1.00 – 1.39
Median EI [a]	24.9	2,220	3,070	55.3 – 76.4	0.97 – 1.34
Methane [d]					
Site EI [a]	24.7	2,220	3,070	54.8 – 75.8	0.96 – 1.33
Median EI [a]	23.9	2,220	3,070	53.1 – 73.4	0.93 – 1.29
Total CA Plans: P66, MPC, AltAir and GCE					
Mixed feed [a, d]	25.8	2,220	3,070	57.3 – 79.2	3.51 – 4.86
Methane [a, d]	24.6	2,220	3,070	54.6 – 75.5	3.35 – 4.63

a. Plant factor energy intensity (EI) expressed as emission rate assuming 100% methane combustion fuel. Site EI is from plant-specific, capacity-weighted data; median EI is from 11 SF Bay Area hydrogen plants that serve or served oil refineries. CA total assumes site EIs for P66 and MPC and median EI for AltAir and GCE.
b. H_2 demand/b biomass feed: lower bound for yield-weighted blend with 0% fish oil targeting maximum diesel production; upper bound for yield-weighted blend with 25% fish oil targeting maximum jet fuel production. **c.** Mass emission at kg/b value in table and capacity of proposed projects, P66: 80,000 b/d; MPC: 48,000 b/d; Altair: 21,500 b/d; GCE: 18,500 b/d. **d.** Mixed feed is 77% methane and 23% propane, the approximate proportion of propane by-production from HEFA processing, and the likely disposition of propane, other process byproduct gases, or both; methane: 100% methane feed to the reforming and shift reactions. *See* Appendix for details.[1]

Total CO_2 emissions from hydrogen plants feeding the currently proposed HEFA refining expansion proposed statewide could exceed 3.5 million tons per year—if the refiners only target diesel production. *See* Table 3. If they all target jet fuel, and increase hydrogen production to do so, those emissions could exceed 4.8 million tons annually. *Id.*

It bears note that this upper bound estimate for targeting jet fuel appears to require increases in permitted hydrogen production at P66 and MPC. Targeting jet fuel at full feed capacity may also require new hydrogen capacity a step beyond further expanding the 1998 vintage[66] P66 Unit 110 or the 1963 vintage[67] MPC No. 1 Hydrogen Plant. And if so, the newer plants could be less energy intensive. The less aged methane reforming merchant plants in California, for example, have a reported median CO_2 emission rate of 76.2 g/MJ H_2.[68] That is 23.3 g/SCF, close to, but less than, the methane reforming median of 23.9 g/SCF in Table 3. Conversely, the belief, based on available evidence until quite recently, that methane emissions from steam reformers do not add significantly to the climate-forcing impact of their huge CO_2 emissions, might turn out to be wrong. Recently reported aerial measurements of California refineries[69] indicate that methane emissions from refinery hydrogen production have been underestimated dramatically. Thus, the upper bound carbon intensity estimates in Table 3 might end up being too high or too low. But questions raised by this uncertainty do not affect its lower bound estimates, and those reveal extreme-high carbon intensity.

Total CO_2 emissions from U.S. petroleum refineries averaged 41.8 kg per barrel crude feed from 2015–2017, the most recent period in which we found U.S. government-reported data for oil refinery CO_2 emitted nationwide.[1] At 55–80 kg per barrel biomass feed, the proposed HEFA hydrogen production *alone* exceeds that petroleum refining carbon intensity by 32–91 percent.

Additional CO_2 would emit from fuel combustion for energy to heat and pressure up HEFA hydro-conversion reactors, precondition and pump their feeds, and distill, then blend their hydrocarbon products. Unverified potential to emit calculations provided by one refiner[1] suggest that these factors could add ~21 kg/b to the 55–80 kg/b from HEFA steam reforming. This ~76–101 kg/b HEFA processing total would exceed the 41.8 kg/b carbon intensity of the average U.S. petroleum refinery by ~82–142 percent. Repurposing refineries for HEFA biofuels production using steam reforming would thus increase the carbon intensity of hydrocarbon fuels processing.

3.2 Local risks associated with HEFA processing

HEFA processing entails air pollution, health, and safety risks to workers and the surrounding community. One of these risks—the intensified catastrophic failure hazard engendered by the more intensive use of hydrogen for HEFA processing—renders HEFA refining in this respect more dangerous than crude processing.

3.2.1 HEFA processing increases refinery explosion and fire risk

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.[70] The oil industry knew that introducing a new and different crude into an existing refinery can introduce new hazards.[71] 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 it now proposes to repurpose for HEFA biomass feeds,[71] and feedstock changes are among the most frequent causes of dangerous upsets in these hydro-conversion reactors.[16]

But differences between the new biomass feedstock refiners now propose and crude oil are bigger than those among crudes which Chevron ignored the hazards of before the August 2012 disaster in Richmond—and involve oxygen in the feed, rather than sulfur as in that disaster.[70]

Chevron Richmond Refinery, 6 Aug 2012. Image: CSB

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."[71] At 10.8–11.5 wt. %, HEFA feeds have very high oxygen content,[1] while the petroleum crude fed to refinery processing has virtually none. Carbonic acid forms from that oxygen in HEFA processing. Carbonic acid corrosion is a known hazard in HEFA processing.[22] 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[71] cannot reliably guide—and could misguide—refiners that attempt to find, then fix, damage from this new hazard before it causes equipment failures.

Worse, high-oxygen HEFA feedstock boosts hydrogen consumption in hydro-conversion reactors dramatically, as shown in Chapter 2. 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.

A specific feedback mechanism underlies this hazard. The hydro-conversion reactions are exothermic: they generate heat.[16 21 22] When they consume more hydrogen, they generate more heat.[21] Then they get hotter, and crack more of their feed, consuming even more hydrogen,[16 21] so "the hotter they get, the faster they get hot."[16] And the reactions proceed at extreme pressures of 600–2,800 pound-force per square inch,[16] 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[16]—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.

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.[22] And given the short track record of HEFA processing, the potential for other, yet-to-manifest, hazards cannot be discounted.

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.

Significant and sometimes catastrophic incidents involving the types of hydrogen processing systems proposed for California HEFA projects are unfortunately common in crude oil refining, as reflected in the following incident briefs posted by *Process Safety Integrity*[72] 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.
- 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 the Tosco (now MPC) Martinez refinery.
- 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.[72]

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.

Refiners have the ability to use extra hydrogen to quench, control, and guard against runaway reactions as described in Chapter 1, 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.[16 22] 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. 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. *See* Table 4 for specific examples.

Indeed, despite current safeguards, hydro-conversion and hydrogen-related process safety hazards which their HEFA conversion projects could worsen contribute to significant flaring incidents at the P66 Rodeo and MPC Martinez refineries frequently. Causal analysis reports for significant flaring show that hydrogen-related hazard incidents occurred at those refineries a combined total of 100 times from January 2010 through December 2020.[1] This is a conservative estimate, since incidents can cause significant impacts without causing environmentally significant flaring, but still represents, on average, and accounting for the Marathon plant closure since April 2020, another hydrogen-related incident at one of those refineries every 39 days.[1]

Sudden unplanned or emergency shutdowns of major hydro-conversion or hydrogen production plants occurred in 84 of these 100 reported process safety hazard incidents.[1] Such sudden forced shutdowns of *both* hydro-conversion and hydrogen production plants occurred in 22 of these incidents.[1] 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.[1]

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.

Table 4. Examples from 100 hydrogen-related process hazard incidents at the Phillips 66 Rodeo and Marathon Martinez refineries, 2010–2020.

Date [a]	Refinery	Hydrodrogen-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 Regulation § 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 given in Table A6 of this report. Notes b–k below further illustrate 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."

3.2.2 HEFA processing would perpetuate localized episodic air pollution

Refinery flares are episodic air polluters. Every time the depressurization-to-flare safeguard dumps process gases in attempts to avoid even worse consequences, that flaring is uncontrolled open-air combustion. Flaring emits a mix of 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 incidents described above flared more than two million cubic feet of vent gas each, and many flared more than ten million.[1]

The increased risk of process upsets associated with HEFA processing concomitantly creates increased risk to the community of acute exposures to air pollutants, with impacts varying with the specifics of the incident and atmospheric conditions at the time when flaring recurs.

In 2005, flaring was linked to episodically elevated local 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.[73] By 2006, the regional air quality management district independently confirmed the link, assessed community-level impacts, and set environmental significance thresholds for refinery flares.[74 75] These same significance thresholds were used to require P66 and MPC to report the hazard data described above.[75]

Thus, each of the hundred hydrogen-related flaring incidents since 2010 at the P66 Rodeo and MPC Martinez refineries discussed above *individually* exceeded a relevant environmental significance threshold for air quality. Therefore, by prolonging the time over which the frequent incidents continue, and likely increasing the frequency of this significant flaring, repurposing refineries for HEFA processing can be expected to cause significant episodic air pollution.

Environmental justice impacts

It bears significant note that the refinery communities currently living with episodic air pollution—which would potentially be worsened by the conversion to HEFA processing—are predominantly populated by people of color. In fact, refineries were found to account for 93% of the statewide population-weighted disparity between people of color and non-Hispanic whites in particulate matter emission burdens associated with all stationary source industries in the state cap-and-trade program.[76] These communities of color tend to suffer from a heavy pre-existing pollution burden, such that additional and disproportionate episodic air pollution exposures would have significant environmental justice implications.

4. DOWNSTREAM — IMPACT OF BIOFUEL CONVERSIONS ON CLIMATE PATHWAYS

This chapter assesses potential impacts of HEFA biofuels expansion on California climate plans and goals. Primary issues of concern are HEFA biofuel volume, total liquid combustion fuel volume, systemic effects of refining and hydrogen use which could create HEFA lock-in, and the timing of choices between zero-emission *versus* liquid combustion fuels. Benchmarks for assessing these impact issues are taken from state roadmaps for the array of decarbonization technologies and measures to be deployed over time to achieve state climate goals—herein, "climate pathways." The state has developed a range of climate pathways, which rely in large part on strategies for replacing petroleum with zero-emission fuels that HEFA growth may disrupt and which reflect, in part, tradeoffs between zero-emission and liquid combustion fuels. Section 4.1 provides background on these climate pathway benchmarks and strategies.

Section 4.2 compares a foreseeable HEFA growth scenario with state climate pathway benchmarks for HEFA biofuel volume, total liquid fuel volume and systemic effects of refining and hydrogen use through mid-century, and estimates potential greenhouse gas emissions. This assessment shows that HEFA biofuel growth has the potential to impact state climate goals significantly. Section 4.3 addresses the timing of choices between zero-emission and liquid combustion fuels, shows that a zero-emission hydrogen alternative could be deployed during a critical window for breaking carbon lock-in, and assesses HEFA growth impacts on the emission prevention, clean fuels development, and transition mitigation effectiveness of this alternative.

4.1 California climate goals and implementation pathway benchmarks background related to HEFA biofuel impact issues assessed

4.1.1 State climate goals and pathways that HEFA biofuels growth could affect

State climate goals call for cutting greenhouse gas emissions 80% below 1990 emissions to a 2050 target of 86.2 million tons per year,[77] for zero-emission vehicles (ZEVs) to be 100% of light-duty vehicle (LDV) sales by 2035 and 100% of the medium- and heavy-duty vehicle (MDV and HDV) fleet by 2045,[78] and for achieving net-zero carbon neutrality by 2045.[79]

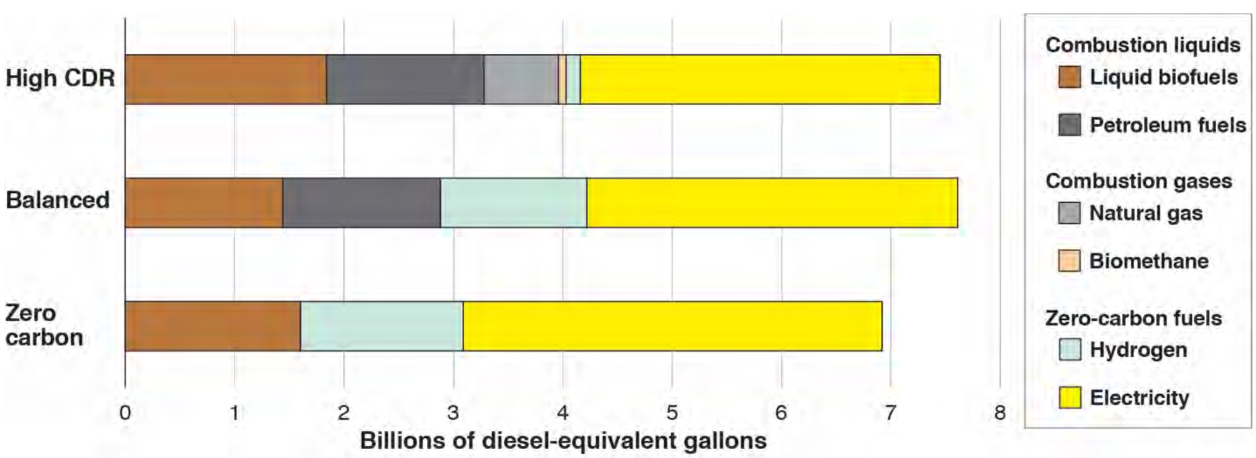
Behind the net-zero goal lies a highly consequential tradeoff: deeper emission cuts require transforming hard-to-decarbonize uses of energy. Relying on carbon dioxide removal-and-sequestration (CDR) instead risks failure to cut emissions until too late. The state has begun to confront this tradeoff by developing climate pathways that range from near-zero carbon to high-CDR. These pathways show how various types of biofuels and other technologies and measures fit into lower-emission and higher-emission approaches to achieving state climate goals.

Pathway scenarios developed by Mahone et al. for the California Energy Commission (CEC),[54] Air Resources Board[55] and Public Utilities Commission,[56] Austin et al. for the University of California,[57] and Reed et al. for UC Irvine and the CEC[58] add semi-quantitative benchmarks to the 2050 emission target, for assessing refinery conversions to biofuels. They join other work in showing the need to decarbonize electricity and electrify transportation.[54–61] Their work "bookends" the zero-carbon to high–CDR range of paths to state climate goals,[55] analyzes the roles of liquid hydrocarbon combustion fuels and hydrogen in this context,[54–58] and addresses potential biomass fuel chain effects on climate pathways.[54 55 57]

4.1.2 State climate pathway liquid fuels volume benchmarks that HEFA biofuels growth could affect

Total liquid transportation fuels benchmark: ~1.6 to 3.3 billion gallons by 2045

All state pathways to net-zero emissions cut liquid petroleum fuels use dramatically, with biofuels replacing only a portion of that petroleum. Chart 2 illustrates the "bookends" of the zero-carbon to high-CDR range of pathways for transportation reported by Mahone et al.[55]



2. California Transportation Fuels Mix in 2045: Balanced and "bookend" pathways to the California net-zero carbon emissions goal.

Adapted from Figure 8 in Mahone et al. (2020a[55]). Fuel shares converted to diesel energy-equivalent gallons based on Air Resources Board LCFS energy density conversion factors. **CDR:** carbon dioxide removal (sequestration).

Total liquid hydrocarbon combustion fuels for transportation in 2045, including petroleum and biofuels, range among the pathways from approximately 1.6 to 3.3 billion gallons/year (Chart 2), which is roughly 9% to18% of statewide petroleum transportation fuels use from 2013–2017.[55] Liquid biofuels account for approximately 1.4 to 1.8 billion gallons/year, which is roughly 40% to 100% of liquid transportation fuels in 2045 (Chart 2). Importantly, up to 100% of the biofuels in these pathways would be derived from cellulosic biomass feedstocks[57 80 81] instead of purpose-grown lipids which HEFA technology relies upon, as discussed below.

HEFA biofuels volume benchmark: zero to 1.5 billion gallons per year through 2045

Many State climate pathways exclude or cap HEFA biofuel. Mahone et al. assume biofuels included in the pathways use cellulosic residues that are not purpose-grown—and cap those fuels in most scenarios to the per capita state share of non-purpose-grown U.S. biomass supply.[54 55] This excludes purpose-grown lipids-derived biofuels such as the HEFA biofuels. Austin et al.[57] assume a cap on lipids biomass that limits HEFA jet fuel and diesel use to a maximum of 0.5–0.6 and 0.8–0.9 billion gallons/year, respectively. Both Austin[57] and Mahone[54 55] cite difficult-to-predict land use emissions as reasons to limit purpose-grown crop and lipid-derived biofuels *as pathway development constraints* rather than as problems with the Low Carbon Fuel Standard (LCFS). This report agrees with that view: the need and ability to limit HEFA volume is a climate pathway impact issue—and local land use impact issue—not a criticism of the LCFS. *See* Box below.

4.1.3 Electrolysis hydrogen benchmarks for systemic energy integration that affect the timing of choices between zero-emission *versus* liquid combustion fuels

To replace combustion fuels in hard-to-electrify sectors, state climate pathways rely in part on "energy integration" measures, which often rely on electrolysis hydrogen, as discussed below.

Hydrogen for hard-to-decarbonize energy uses

Hydrogen, instead of HEFA diesel, could fuel long-haul freight and shipping. Hydrogen stores energy used to produce it so that energy can be used *where* it is needed for end-uses of energy that are hard to electrify directly, and *when* it is needed, for use of solar and wind energy at night and during calm winds. Climate pathways use hydrogen for hard-to-electrify emission sources in transportation, buildings and industry, and to support renewable electricity grids.

What is renewable-powered electrolysis hydrogen?

Electrolysis produces hydrogen from water using electricity. Oxygen is the byproduct, so solar and wind-powered electrolysis produces zero-emission hydrogen. State climate pathways consider three types of electrolysis: alkaline, proton-exchange membrane, and solid oxide electrolyzers.[55 58] The alkaline and proton-exchange membrane technologies have been proven in commercial practice.[58] Renewable-powered electrolysis plants are being built and used at increasing scale elsewhere,[82] and California has begun efforts to deploy this technology.[58]

Biofuels in the Low Carbon Fuel Standard (LCFS)

What the LCFS does	**What we still need to do in other ways**
Reduces the carbon intensity (CI) of transportation fuels	Reduce carbon-based fuel volume and volume-related mass emissions
Reduces transportation fuels CI by increments, over increments of time	Avoid committing to fuels that would exceed 2045 climate targets despite early incremental CI cuts
Moves money from higher-CI to lower-CI fuel producers	Build long-lasting production only for those fuels which will not exceed 2045 climate targets
Applies to fuels sold for use in the state, including biofuels, fossil fuels, electricity and hydrogen fuels	Prevent imports that people elsewhere need for their own biomass-based food and fuel
Compares the CI of each biofuel to the CI of the petroleum fuel it could replace across the whole fuel chains of both. To move dollars from higher to lower CI fuel producers, a specific "lifecycle" CI number estimate is made for each biofuel, from each type of biomass production, biofuel production, and fuel combustion in transportation for that biofuel	Directly monitor all the worldwide interactions of biomass fuel and food chains—to find out *before* an impact occurs. For example, what if increasing demand for soy-based biofuel leads farmers to buy pastureland for soybean plantations, leading displaced ranchers to fell rainforest for pastureland in another environment, state, or country?
Relies on currently quantifiable data for carbon emissions from harvesting each specific type of biomass for biofuel. The LCFS *has to* do this to come up with the specific CI numbers it uses to incrementally reduce transportation fuels CI now	Realize that some serious risks need to be avoided before they become realities which can be fully quantified, find out which biofuels pose such risks, and avoid taking those serious risks
This report does not assess the performance of the LCFS for its intended purpose — that is beyond the report scope. *This report should not be interpreted as a criticism or endorsement of the LCFS.*	**HEFA biofuel** risks that the LCFS is not designed to address are assessed in this report. *There are other ways to address these HEFA risks.*

Electrolysis is not the only proven hydrogen production technology considered in state climate pathways; however, it is the one that can store solar and wind energy, and electrolysis hydrogen can decarbonize hard-to-electrify emission sources without relying on CDR.

Renewable-powered electrolysis for zero-emission transportation

Renewable-powered electrolysis hydrogen could be critical for zero-emission transportation. Hydrogen fuel shares shown in Chart 2 represent fuel cell-electric vehicle (FCEV) fueling. Fuel cells in FCEVs convert the hydrogen back into electricity that powers their electric motors. Thus, hydrogen stored in its fuel tank is the "battery" for this type of electric vehicle. FCEVs can decarbonize transportation uses of energy where battery-electric vehicles (BEVs) might be more costly, such as long-haul freight and shipping, in which the size and mass of BEV batteries needed to haul large loads long distances reduce the load-hauling capacity of BEVs.

This zero-emission electrolysis hydrogen also plays a key role because it fuels FCEVs without relying on CDR. These zero-emission FCEVs appear crucial to the feasibility of the state climate goal for a 100% ZEV medium- and heavy-duty fleet by 2045.[78] This raises a turnkey issue because—as the difference in hydrogen fuel share between the High-CDR and the Balanced pathways in Chart 2 reflects—both electrolysis and FCEVs are proven technologies, but they nevertheless face significant infrastructure deployment challenges.[54–61]

In state climate pathways, renewable hydrogen use in transportation grows from an average of 1.24 million standard cubic feet per day (MMSCFD) in 2019[83] to roughly 1,020–1,080 MMSCFD by 2045.[56–58] This 2045 range reflects different scenarios for the mix of BEVs and FCEVs in different vehicle classes. The low end excludes FCEV use in LDVs[58] while the high end is a "central scenario" that includes both BEV and FCEV use in all vehicle classes.[57]

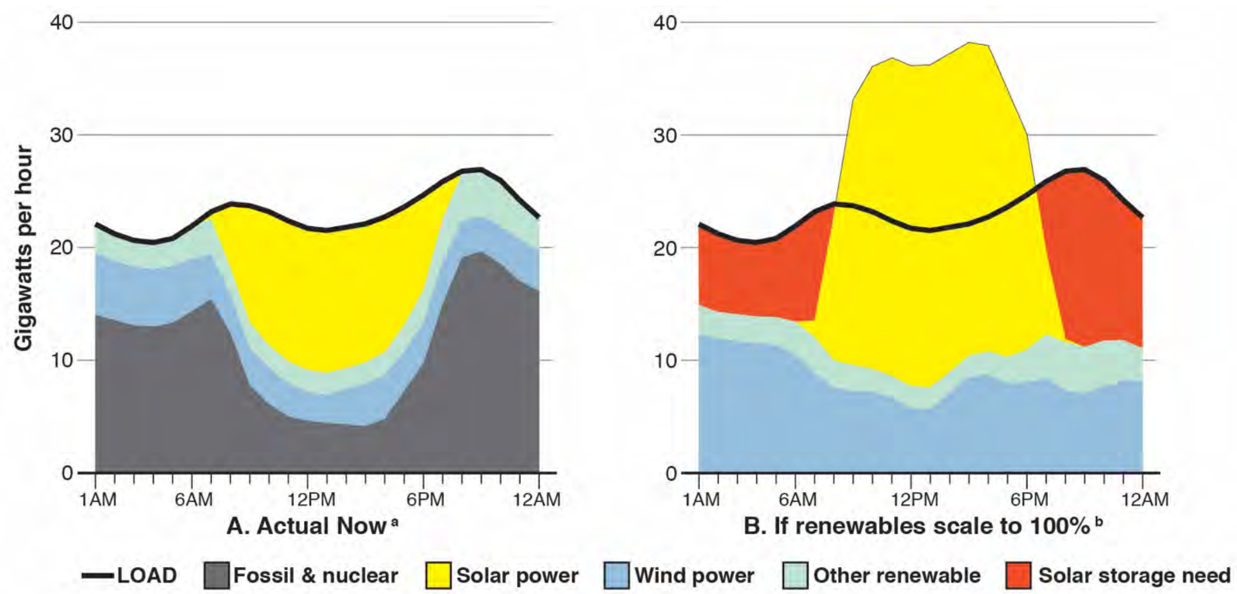
Renewable-powered electrolysis for future solar and wind power growth

Hydrogen produced by electrolysis can store solar and wind power energy, which supports the renewable energy growth needed to produce more zero-emission FCEV fuel by electrolysis. Electrolysis hydrogen plays a key role in the further growth of solar and wind energy resources, because it can store that energy efficiently for use overnight as well as over longer windless periods. The direct use of electricity for energy—in grid jargon, the "load"—occurs in the same instant that electricity is generated. This is a challenge for climate pathways because solar and wind power are intermittent electricity generators, while electricity use (load) is continuous, and varies differently from solar and wind power generation over time.

Substantial energy storage will be critical to a renewable electricity grid. There are other storage technologies such as ion batteries, compressed air, hydropower management and power-to-gas turbines, and climate pathways include multiple measures to balance renewable grids.[54–61] However, electrolysis hydrogen is particularly beneficial because it can provide efficient long-term storage over wind cycles as well as short-term storage over solar cycles while fueling ZEV growth. Charts 3 A and B below illustrate the scale of the solar energy storage need.

Load, the thick black curve that does not change from Chart A to Chart B, shows how much electric power we need and when we need it. In the renewables scale-up scenario (B), the yellow above the load curve is peak solar generation that could be wasted ("curtailed") if it cannot be stored, and the red below the load curve indicates "blackouts" we could avoid by storage of the otherwise wasted energy for use when it gets dark. This is only an example on one hypothetical day, but to continue the illustration, the energy that storage could shift, from yellow above the load curve to red below it, compares to the energy stored in ~1,500 MMSCF of hydrogen.

State climate pathways assign electrolysis a key role in meeting part of this enormous grid-balancing need. Energy storage would be accomplished by a mix of technologies and measures, including renewable-powered electrolysis hydrogen and others.[54–58] Increasing needs for energy storage in climate pathways become substantial before 2030, and the role of electrolysis hydrogen in this storage grows by up to approximately 420 MMSCFD by 2045.[58]



3. California electricity load shape on 20 April: Actual in 2021 *v.* renewable power.

A high-renewables future will require short-term storage of peak solar power generation for use at night. *See* yellow above and red below the black line showing total electricity load that can be used at the time power is generated, in this example. Solar electrolysis hydrogen stored in the fuel tanks of zero-emission trucks could be a needed part of the solution. **a.** Data reported for 20 April 2021.[84] **b.** Example scenario scales up solar and wind data proportionately to replace total fossil and nuclear generation on this day.

Renewable-powered electrolysis hydrogen for least-cost energy integration measures

Climate pathway analyses underscore both the challenge and the benefits of integrating electrolysis hydrogen across the transportation and electricity sectors. The scale-up challenge appears urgent. From ~2.71 MMSCFD by the end of 2021,[58] in-state electrolysis capacity would reach ~1,440–1,500 MMSCFD by 2045 to meet all of the transportation and energy storage needs for hydrogen discussed above.[56–58] Ramping to that scale, however, achieves economies of scale in electrolysis hydrogen production and fueling that overcome significant deployment barriers to growth of this zero-emission FCEV fuel; electrolysis hydrogen costs can be expected to fall from above to below those of steam reforming hydrogen around 2025–2035.[55 56 58 84 85] Policy intervention to meet critical needs for earlier deployment is assumed to drive ramp-up.[58]

Then, once deployed at scale, integration of electrolysis, transportation and the electricity grid can provide multiple systemic benefits. It can cut fuel costs by enabling FCEVs that are more efficient than diesel or biofuel combustion vehicles,[86] cut health costs by enabling zero-emission FCEVs,[57 87] cut energy costs by using otherwise wasted peak solar and wind power,[58 85] and enable priority measures needed to decarbonize hard-to-electrify energy emissions.[54 55 57 58 85] From the perspective of achieving lower-risk climate stabilization pathways, renewable-powered electrolysis hydrogen may be viewed as a stay-in-business investment.

State climate pathway benchmarks for hydrogen energy storage, transportation fuel, and refining that HEFA biofuel growth could affect

Electrolysis hydrogen production in state pathways could reach ~ 420 MMSCFD for energy storage and approximately 1,020–1,080 MMSCFD for transportation, as noted above, and could grow due to a third need and opportunity, which also could be affected by HEFA biofuel growth. The Hydrogen Roadmap in state climate pathways includes converting petroleum refining to renewable hydrogen production,[58] an enormously consequential measure, given that current hydrogen capacity committed to crude refining statewide totals ~1,216 MMSCFD.[88]

4.1.4 <u>Replacement of gasoline with BEVs would idle crude refining capacity for distillates as well, accelerating growth of a petroleum diesel replacement fuels market that ZEVs, biofuels, or both could capture</u>

BEVs could replace gasoline quickly

Gasoline combustion inefficiencies make battery electric vehicle (BEV) replacement of gasoline a cost-saving climate pathway measure. By 2015 BEVs may already have had lower total ownership cost than gasoline passenger vehicles in California.[89] BEVs go three times as far per unit energy as same-size vehicles burning gasoline,[90] have fewer moving parts to wear and fix—for example, no BEV transmissions—have a fast-expanding range, and a mostly-ready fuel delivery grid. Economics alone should make gasoline obsolete as fast as old cars and trucks wear out, strongly supporting the feasibility of state goals for BEVs and other zero-emission vehicles (ZEVs) to comprise 100% of light-duty vehicle (LDV) sales by 2035.[78] State climate pathways show that BEVs can be 30–100% of LDV sales by 2030–2035, 60–100% of LDV and medium-duty vehicle sales by 2030–2045, and comprise most of the California vehicle fleet by 2045.[55 57] Electricity-powered LDVs and MDVs would thus replace gasoline relatively quickly.

Gasoline replacement would idle petroleum distillates production

Crude refining limitations force petroleum distillate production cuts as gasoline is replaced. Existing California refineries cannot make distillates (diesel and jet fuel) without coproducing gasoline. From 2010–2019 their statewide distillates-to-gasoline production volumes ratio was 0.601 and varied annually from only 0.550 to 0.637.[91] This reflects hard limits on refining technology: crude distillation yields a gasoline hydrocarbon fraction, and refineries are designed and built to convert other distillation fractions to gasoline, not to convert gasoline to distillates. During October–December in 2010–2019, when refinery gasoline production was often down for maintenance while distillate demand remained high, the median distillate-to-gasoline ratio rose only to 0.615.[1] That is a conservative estimate for future conditions, as refiners keep crude rates high by short-term storage of light distillation yield for gasoline production after equipment is returned to service.[1 91] When gasoline and jet fuel demand fell over 12 months following the 19 March 2020 COVID-19 lockdown[36] the ratio fell to 0.515.[91] Future permanent loss of gasoline markets could cut petroleum distillate production to less than 0.615 gallons per gallon gasoline. Climate pathways thus replace petroleum distillates along with gasoline.

Existing distillates distribution infrastructure favors biofuels, emphasizing the need for early deployment of FCEVs and zero-emission electrolysis hydrogen

Fuel cell-electric vehicle (FCEV) transportation faces a challenge in the fact that existing petroleum distillates distribution infrastructure can be repurposed to deliver drop-in biofuels to truck, ship, and jet fuel tanks, while hydrogen fuel infrastructure for FCEVs must ramp up. Hydrogen-fueled FCEV growth thus faces deployment challenges which biofuels do not.[54–61] Those infrastructure challenges underly the urgent needs for early deployment of FCEVs and electrolysis hydrogen identified in state climate pathway analyses.[54–58] Indeed, early deployment is an underlying component of the climate pathway benchmarks identified above.

4.2 HEFA biofuels growth could exceed state climate pathway benchmarks for liquid fuels volumes, interfere with achieving electrolysis hydrogen energy integration benchmarks, and exceed the state climate target for emissions in 2050

4.2.1 HEFA biofuels growth could exceed state climate pathway benchmarks for liquid fuels volumes

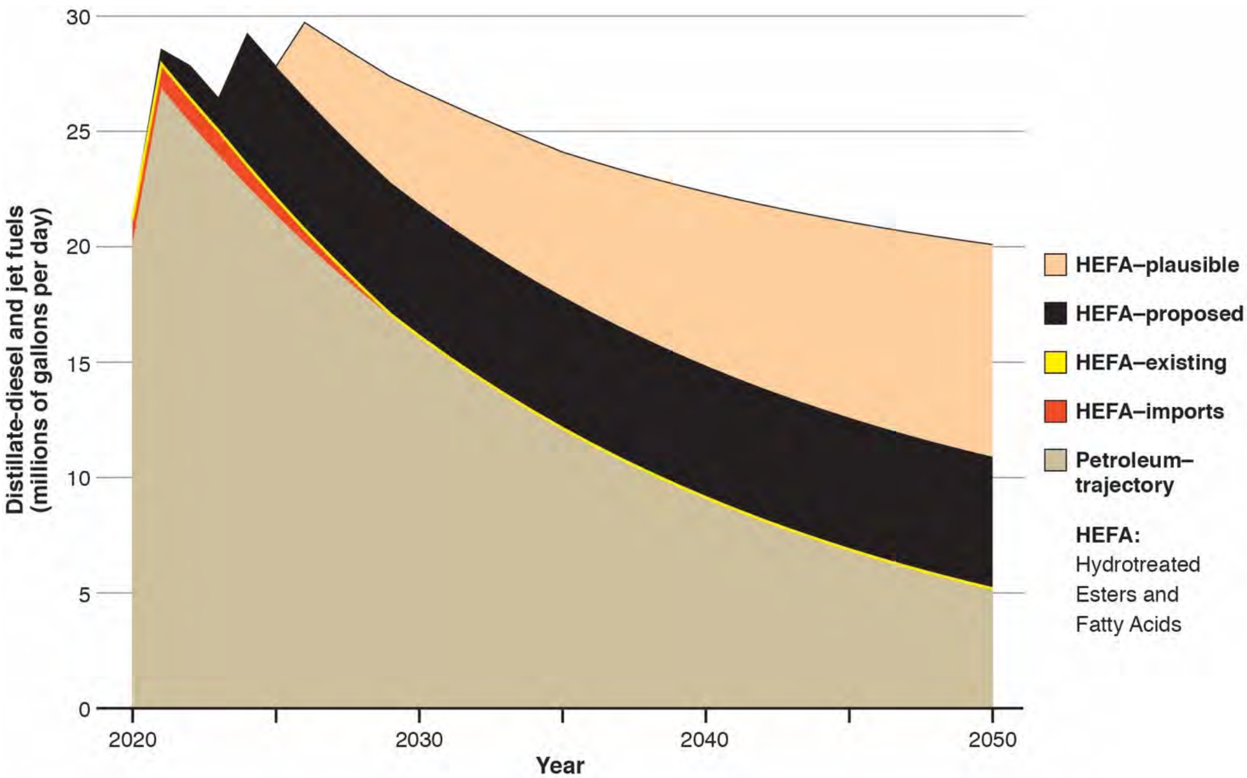
Proposed projects would exceed HEFA biofuel caps

Current proposals to repurpose in-state crude refining assets for HEFA biofuels could exceed the biofuel caps in state climate pathways by 2025. New in-state HEFA distillate (diesel and jet fuel) production proposed by P66, MPC, AltAir and GCE for the California fuels market would, in combination, total ~2.1 billion gal./y and is planned to be fully operational by 2025.[1–6] If fully implemented, these current plans alone would exceed the HEFA diesel and jet fuel caps of 0.0–1.5 billion gal./y in state climate pathways (§4.1.2).

Continued repurposing of idled crude refining assets for HEFA biofuels could exceed the total liquid combustion fuels volume benchmarks in state climate pathways

Further HEFA biofuels growth, driven by incentives for refiners to repurpose soon-to-be-stranded crude refining assets before FCEVs can be deployed at scale, could exceed total liquid fuels combustion benchmarks for 2045 in state climate pathways. As BEVs replace petroleum distillates along with gasoline, crude refiners could repurpose idled petroleum assets for HEFA distillates before FCEVs ramp up (§ 4.1.4), and refiners would be highly incentivized to protect those otherwise stranded assets (Chapter 1).

Chart 4 illustrates a plausible future HEFA biofuel growth trajectory in this scenario. Declining petroleum diesel and jet fuel production forced by gasoline replacement with BEVs (gray-green, bottom) could no longer be fully replaced by currently proposed HEFA production (black) by 2025–2026. Meanwhile the idled crude refinery hydrogen production and processing assets repurpose for HEFA production (light brown, top). As more petroleum refining assets are stranded, more existing refinery hydrogen production is repurposed for HEFA fuels, increasing the additional HEFA production from left to right in Chart 4.



4. Combustion fuels additive potential of HEFA diesel and jet production in California.

As electric vehicles replace gasoline, stranding petroleum refining assets, continuing HEFA biorefining expansion could add as much as 15 million gallons per day (290%) to the remaining petroleum distillate-diesel and jet fuel refined in California by 2050. Locking in this combustion fuels additive could further entrench the incumbent combustion fuels technology in a negative competition with cleaner and lower-carbon technologies, such as renewable-powered hydrogen fuel cell electric vehicles (FCEVs). That could result in continued diesel combustion for long-haul freight and shipping which might otherwise be decarbonized by zero emission hydrogen-fueled FCEVs.

Petroleum-trajectory for cuts in petroleum refining of distillate (D) and jet (J) fuels that will be driven by gasoline replacement with lower-cost electric vehicles, since petroleum refineries cannot produce as much D+J when cutting gasoline (G) production. It is based on 5.56%/yr light duty vehicle stock turnover and a D+J:G refining ratio of 0.615. This ratio is the median from the fourth quarter of 2010–2019, when refinery gasoline production is often down for maintenance, and is thus relatively conservative. Similarly, state policy targets a 100% zero-emission LDV fleet by 2045 and could drive more than 5.56%/yr stock turnover. Values for 2020–2021 reflect the expected partial rebound from COVID-19.

HEFA-imports and **HEFA-existing** are the mean D+J "renewable" volumes imported, and refined in the state, respectively, from 2017–2019. The potential in-state expansion shown could squeeze out imports.

HEFA-proposed is currently proposed new in-state capacity based on 80.9% D+J yield on HEFA feed including the Phillips 66 Rodeo, Marathon Martinez, Altair Paramount, and GCE Bakersfield projects, which represent 47.6%, 28.6%, 12.8%, and 11.0% of this proposed 5.71 MM gal/day total, respectively.

HEFA-plausible: as it is idled along the petroleum-based trajectory shown, refinery hydrogen capacity is repurposed for HEFA biofuel projects, starting in 2026. This scenario assumes feedstock and permits are acquired, less petroleum replacement than state climate pathways,[55] and slower HEFA growth than new global HEFA capacity expansion plans targeting the California fuels market[92] anticipate. Fuel volumes supported by repurposed hydrogen capacity are based on H_2 demand for processing yield-weighted feedstock blends with fish oil growing from 0% to 25%, and a J : D product slate ratio growing from 1: 5.3 to 1: 2, during 2025–2035.

For data and methodological details see Table A7.[1]

Refining and combustion of HEFA distillates in California could thus reach ~15.0 million gal./d (5.47 billion gal./y), ~290% of the remaining petroleum distillates production, by 2050.[1.] HEFA distillate production in this scenario (5.47 billion gal./y) would exceed the 1.6–3.3 billion gal./y range of state climate pathways for combustion of *all* liquid transportation fuels, including petroleum and biofuel liquids, in 2045.[55] This excess combustion fuel would squeeze out cleaner fuels, and emit future carbon, from a substantial share of the emergent petroleum distillate fuels replacement market—a fuel share which HEFA refiners would then be motivated to retain.

This climate impact of HEFA biofuels growth is reasonably foreseeable

The scenario shown in Chart 4 is an illustration, not a worst case. It assumes slower growth of HEFA biofuel combustion in California than global investors anticipate, less petroleum fuels replacement than state climate pathways, and no growth in distillates demand. Worldwide, the currently planned HEFA refining projects targeting California fuel sales total ~5.2 billion gal./y by 2025.[92] HEFA growth by 2025 in the Chart 4 scenario is less than half of those plans. State climate pathways reported by Mahone et al.[55] replace ~92% of current petroleum use by 2045, which would lower the petroleum distillate curve in Chart 4, increasing the potential volume of petroleum replacement by HEFA biofuel. Further, in all foreseeable pathways, refiners would be incentivized to protect their assets and fuel markets—and there are additional reasons why HEFA biofuel could become locked-in, as discussed below.

4.2.2 <u>Continued use of steam reforming for refinery hydrogen could interfere with meeting state climate pathway benchmarks for electrolysis hydrogen energy integration, and lock HEFA biofuels in place instead of supporting transitions to zero-emission fuels</u>

In contradiction to the conversion of refineries to renewable hydrogen in state climate pathways (§4.1.3), refiners propose to repurpose their high-carbon steam reforming hydrogen production assets for HEFA biofuels refining (chapters 1, 3). This would foreclose the use of that hydrogen for early deployment of ZEVs and renewable energy storage, the use of those sites for potentially least-cost FCEV fueling and renewable grid-balancing, and the future use of that hydrogen by HEFA refiners in a pivot to zero emission fuels. These potential impacts, together with HEFA refiner motivations to retain market share (§ 4.2.1), could result in HEFA diesel becoming a locked-in rather than a transitional fuel.

Repurposing refinery steam reforming for HEFA would circumvent a renewable hydrogen benchmark and interfere with early deployment for FCEVs and energy storage, slowing growth in ZEV hydrogen fuel and renewable energy for ZEV fuels production

Repurposing refinery steam reforming for HEFA fuels, as refiners propose,[2–6] instead of switching crude refining to renewable hydrogen, as the hydrogen roadmap in state climate pathways envisions,[58] could foreclose a very significant deployment potential for zero-emission fuels. Nearly all hydrogen production in California now is steam reforming hydrogen committed to oil refining.[56] Statewide, crude refinery hydrogen capacity totals ~1,216 MMSCFD,[88] some 980 times renewable hydrogen use for transportation in 2019 (1.24 SCFD)[83] and ~450 times planned 2021 electrolysis hydrogen capacity (~2.71 MMSCFD).[58] Repurposing crude refining hydrogen production for HEFA refining would perpetuate the commitment of this hydrogen to liquid combustion fuels instead of other potential uses. Importantly, that hydrogen would not be available for early deployment of FCEVs in the hard-to-electrify long haul freight and shipping sectors, or energy storage grid-balancing that will be needed for solar and wind power growth to fuel both zero emission FCEVs and BEVs.

By blocking the conversion of idled refinery hydrogen capacity to renewable hydrogen, repurposing idled crude refinery steam reforming for HEFA biofuels could slow ZEV fuels growth. Chart 5 below illustrates the scale of several potential impacts. Hydrogen demand for HEFA biofuels could exceed that for early deployment of FCEVs (Chart, 2025), exceed hydrogen demand for energy storage grid-balancing (Chart, 2045), and rival FCEV fuel demand for hydrogen in climate pathways through mid-century (*Id.*). ZEV growth could be slowed by foreclosing significant potential for zero-carbon hydrogen and electricity to produce it.

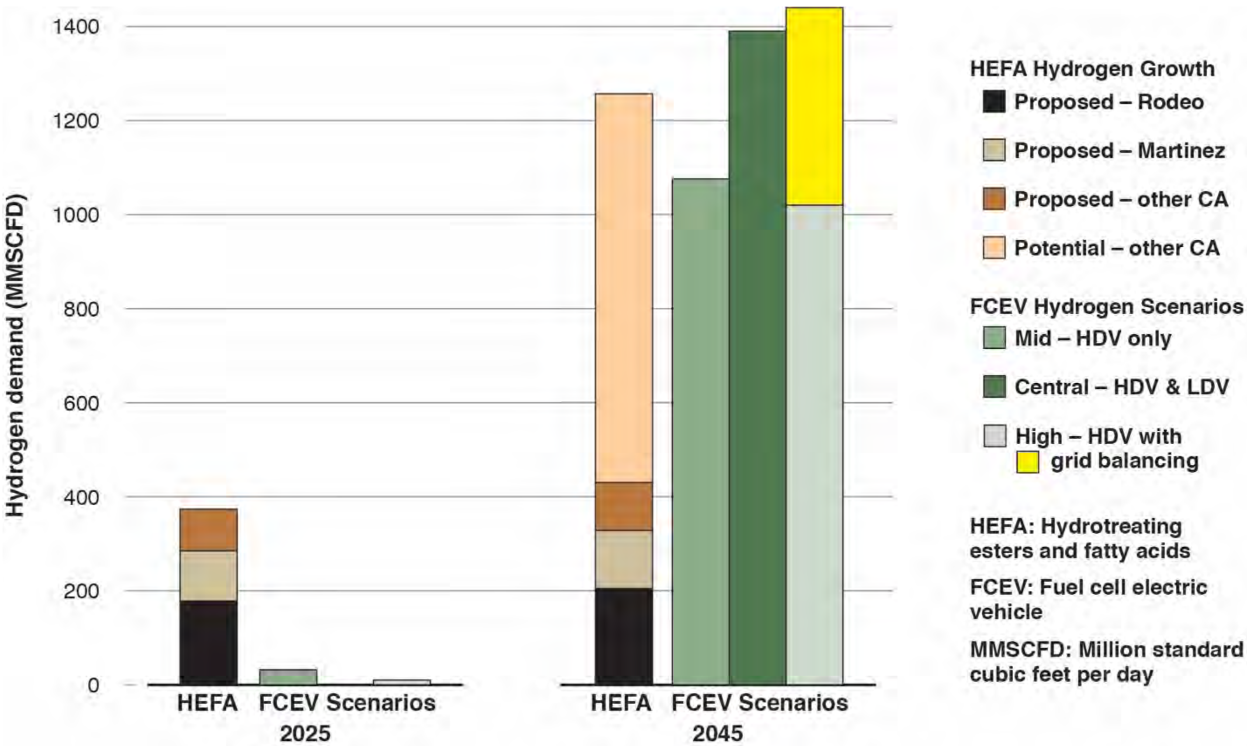
Repurposing refinery steam reforming could foreclose electrolysis deployment in key locations, potentially blocking least-cost FCEV fueling and grid-balancing deployment

Repurposing idled crude refinery steam reforming for HEFA biofuel production would foreclose reuse of otherwise idled refinery sites for renewable-powered electrolysis hydrogen. This site foreclosure impact could be important because of the potential electrolysis sites availability and location. Proximity to end-use is among the most important factors in the feasibility of renewable hydrogen build-out,[58] and refineries are near major California freight and shipping corridors and ports, where dense land uses make the otherwise idled sites especially useful for electrolysis siting. Repurposing crude refineries for HEFA biofuels could thus slow the rapid expansion of renewable-powered electrolysis hydrogen needed in climate pathways.

Continued use of steam reforming would lock HEFA refiners out of future ZEV fueling, further contributing to HEFA combustion fuels lock-in

Committing HEFA refineries to carbon-intensive steam reforming hydrogen would lock the refiners, who then would not be able to pivot toward future fueling of zero-emission FCEVs, into continued biofuel production. HEFA refiners would thus compete with hydrogen-fueled FCEVs in the new markets for fuels to replace petroleum diesel. In this HEFA growth scenario, the hydrogen lock-in, electrolysis site lockout, and ZEV fuel impacts described directly above could be expected to reinforce their entrenched position in those markets. This would have the effect of locking refiners into biofuels instead of ZEV fuels, thereby locking-in continued biofuel use at the expense of a transition to zero-emission fuels.

Crucially, multiple state pathway scenario analyses[54–56, 58] show that the simultaneous scale-up of FCEVs in hard-to-electrify sectors, renewable-powered electrolysis for their zero-emission fuel, and solar and wind power electricity to produce that hydrogen, already faces substantial challenges—apart from this competition with entrenched HEFA biofuel refiners.



5. Potential growth in hydrogen demand for HEFA biorefineries, fuel cell electric vehicle (FCEV) goods movement, and renewable electricity grid balancing to 2025 and 2045.

HEFA biorefineries could slow the growth of zero-emission goods movement, and of renewable electricity, by committing limited hydrogen supplies to drop-in diesel before the cleaner technologies ramp up (chart, 2025), by rivaling their demand for large new hydrogen supplies through mid-century (chart, 2045), and by committing to the wrong type of hydrogen production technology. H_2 supplied by electrolysis of water with renewable electricity could fuel FCEVs to decarbonize long-haul goods movement, and could store peak solar and wind energy to balance the electricity grid, enabling further growth in those intermittent energy resources. However, nearly all California H_2 production is committed to oil refining as of 2021. Refiners produce this H_2 by carbon-intensive steam reforming, and propose to repurpose that fossil fuel H_2 technology, which could not pivot to zero-emission FCEVs or grid balancing, in their crude-to-biofuel refinery conversions.

HEFA proposed based on H_2 demand estimated for P66 Rodeo, MPC Martinez, and other California HEFA projects proposed or in construction as of May 2021. H_2 demand increases from 2025–2045 as HEFA feedstock, jet fuel, and H_2/b demands increase. For data and methods details *see* Table A7.[1]

HEFA potential based on H_2 production capacity at California petroleum refineries, additional to that for currently proposed projects, which could be idled and repurposed for potential HEFA projects along the trajectory shown in Chart 4. *See* Table A7 for data and details of methods.[1]

FCEV Mid – HDV only from Mahone et al. (2020b),[56] FCEVs are ~2% and 50% of new heavy duty vehicle sales in California and other U.S. western states by 2025 and 2045, respectively.[56]

Central – HDV & LDV from Austin et al. (2021), H_2 for California transportation, central scenario, LC1.[57]

High – HDV with grid balancing from Reed et al. (2020), showing here two components of total demand from their high case in California: non-LDV H_2 demand in ca. 2025 and 2045, and H_2 demand for storage and firm load that will be needed to balance the electricity grid as solar and wind power grow, ca. 2045.[58]

4.2.3 Potential carbon emissions could exceed the 2050 climate target

CO_2e emissions from the HEFA growth scenario were estimated based on LCFS carbon intensity values[86] weighted by the HEFA fuels mix in this scenario,[1] accounting for emission shifting effects described in Chapter 2. Accounting for this emission shift that would be caused by replacing petroleum with excess HEFA biofuel use in California at the expense of abilities to do so elsewhere—excluding any added land use impact—is consistent with the LCFS and state climate policy regarding emission "leakage."[62] Results show that HEFA diesel and jet fuel CO_2e emissions in this scenario could reach 66.9 million tons (Mt) per year in 2050. *See* Table 5.

Table 5. Potential CO_2e emissions in 2050 from HEFA distillates refined and used in California.

Distillates volume		
HEFA distillates refined and burned in CA [a]	5.47	billion gallons per year
CA per capita share of lipid-based biofuel [b]	0.58	billion gallons per year
Excess lipids shifted to CA for HEFA biofuel [c]	4.89	billion gallons per year
Distillate fuels mix		
HEFA diesel refined and burned in CA [d]	66.7	percentage of distillates
HEFA jet fuel refined and burned in CA [d]	33.3	percentage of distillates
Fuel chain carbon intensity		
HEFA diesel carbon intensity [e]	7.62	kg CO_2e/gallon
HEFA jet fuel carbon intensity [e]	8.06	kg CO_2e/gallon
Petroleum diesel carbon intensity [e]	13.50	kg CO_2e/gallon
Petroleum jet fuel carbon intensity [e]	11.29	kg CO_2e/gallon
Emissions (millions of metric tons as CO_2e)		
From CA use of per capita share of lipids	4.50	millions of metric tons per year
From excess CA HEFA use shifted to CA	37.98	millions of metric tons per year
Emissions shift to other states and nations [f]	24.44	millions of metric tons per year
Total HEFA distillate emissions	66.92	millions of metric tons per year

a. Potential 2050 HEFA distillates refinery production and use in California in the scenario shown in Chart 4.[1]
b. Statewide per capita share of U.S. farm yield for all uses of lipids used in part for biofuels, from data in Table 1, converted to distillates volume based on a feed specific gravity of 0.914 and a 0.809 feed-to-distillate fuel conversion efficiency. Importantly, these purpose-grown lipids have other existing uses (Chapter 2).
c. Excess lipid biomass taken from other states or nations. This share of limited lipid biomass could not be used elsewhere to replace petroleum with HEFA biofuels. Per capita share of total U.S. production for all uses, rather than that share of lipids available for biofuel, represents a conservative assumption in this estimate.
d. Distillate fuels mix in 2050 (1 gallon jet fuel to 3 gallons diesel) as described in Table A7 part f.[1]
e. Carbon intensity (CI) values from tables 3, 7-1, and 8 of the California LCFS Regulation.[86] HEFA values used (shown) were derived by apportioning "fats/oils/grease residues" and "any feedstocks derived from plant oils" at 31% and 69%, respectively, based on the data in Table 1.
f. Future emissions that would not occur if other states and nations had access to the lipid feedstock committed to California biofuel refining and combustion in excess of the state per capita share shown. Shifted emissions based on the difference between HEFA and petroleum CI values for each fuel, applied to its fuels mix percent of excess lipid-based distillates shifted to CA for HEFA biofuel. Accounting for emissions caused by replacing petroleum in CA *instead of* elsewhere, separately from any added land use impact, is consistent with the LCFS and state climate policy regarding "leakage."[62] Total emissions thus include shifted emissions.

Emissions from the remaining petroleum distillate fuels in this scenario, ~5,113,000 gal./d or 1.87 billion gal./y (Chart 4; Table A7[1]), would add 22.1–24.2 Mt/y, if diesel is 25–75% of the 2050 petroleum distillates mix, at the petroleum carbon intensities in Table 5. Thus, distillate transportation fuel emissions alone (89–91 Mt/y) could exceed the 86.2 Mt/y 2050 state target for CO_2e emissions from all activities statewide.[77] Total 2050 emissions would be larger unless zeroed out in all other activities statewide. Repurposing idled petroleum refinery assets for HEFA biofuels threatens state climate goals.

4.3 A zero-emission electrolysis hydrogen alternative can be deployed during a crucial window for breaking carbon lock-in: HEFA biofuels growth could impact the timing, and thus the emission prevention, clean fuels development, and transition benefits, of this zero-emission electrolysis hydrogen alternative.

Potential benefits to climate pathways from converting hydrogen production to renewable-powered electrolysis (electrolysis) at refinery sites were assessed with and without HEFA biofuels expansion. The "HEFA Case" captures proposed and potential HEFA growth; the "No HEFA Case" is consistent state climate pathways that exclude purpose-grown lipids-derived biofuels in favor of cellulosic residue-derived biofuels.[54 55] Conversion to electrolysis is assumed to occur at crude refineries in both cases, consistent with the hydrogen road map in state climate pathways,[58] but as an early deployment measure—assumed to occur during 2021–2026. This measure could reduce refinery carbon intensity, increase zero-emission transportation and electricity growth, and reduce local transition impacts significantly, and would be more effective if coupled with a cap on HEFA biofuels.

4.3.1 <u>Electrolysis would prevent HEFA biofuels from increasing the carbon intensity of hydrocarbon fuels refining</u>

Deployment timing emerges as the crucial issue in this analysis. "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."[70] The design phase for HEFA refinery conversions, and petroleum refinery turnarounds that occur on 3- to 5-year cycles are critical insertion points for electrolysis in place of carbon-intensive steam reforming. This zero-emission measure would cut the carbon intensity of refining at any time, however, climate stabilization benefit is directly related to the cumulative emission cut achieved, so the effectiveness of this measure would also depend upon how quickly it would be deployed.

Refining CI benefits in the HEFA Case

Replacing steam reforming with electrolysis could cut the carbon intensity (CI) of HEFA refining by ~72–79%, from ~76–101 kg/b to ~21 kg/b refinery feed (Chapter 3). This would cut the CI of HEFA fuels processing from significantly above that of the average U.S. petroleum refinery (~50 kg/b crude; *Id.*) to significantly below the CI of the average U.S. crude refinery.

Refining CI benefits in the No HEFA Case

Replacing steam reforming with electrolysis at petroleum refineries would reduce CI by ~34% based on San Francisco Bay Area data,[66] however, in other states or nations where refiners run less carbon-intensive crude and product slates than in California, this ~34% may not apply.[64]

Refining CI reduction effectiveness

Cumulative emission cuts from hydrogen production would be the same in both cases since hydrogen emissions would be eliminated from HEFA refineries in both cases. Based on the CI values above and the HEFA growth trajectory[1] in Chart 4 this measure could prevent ~194–282 million tons (Mt) of CO_2 emission from HEFA hydrogen production through 2050. Petroleum refinery emissions could be cut by 103 Mt through 2050, based on the median mixed feed CI of steam reforming (24.9 g/SCF, Table 3) and the remaining refinery hydrogen production underlying the distillates trajectory in Chart 4 from 2026–2050.[1] Total direct *cumulative* emissions prevented could be ~297–400 Mt. *Annual* fuel chain emissions from all distillates in transportation in 2050 (89–91 Mt/y) could be cut by ~12–16%, to ~76–78 Mt/y in the HEFA Case. In the No HEFA Case annual fuel chain emissions from petroleum distillates in 2050 (~22–24 Mt/y) could be cut by ~8–9%, to ~20–22 Mt/y, although use of other biofuels along with ZEVs could add to that 20–22 Mt/y significantly. This measure would be effective in all cases, and far more effective in climate pathways that cap HEFA growth and transition to ZEVs.

4.3.2 <u>Use of electrolysis would facilitate development of hydrogen for potential future use in transportation and energy storage</u>

Deployment timing again is crucial. Electrolysis can integrate energy transformation measures across transportation and electricity, speeding both FCEV growth and renewable power growth (§ 4.1). Benefits of this energy integration measure could coincide with a window of opportunity to break free from carbon lock-in, which opened with the beginning of petroleum asset stranding shown in Chapter 1 and could close if refiner attempts to repurpose those assets entrench a new source of carbon in the combustion fuel chain. As Seto et al. conclude:

> "Understanding how and when lock-in emerges also helps identify windows of opportunity when transitions to alternative technologies and paths are possible [.] ... either in emergent realms and sectors where no technology or development path has yet become dominant and locked-in or at moments when locked-in realms and sectors are disrupted by technological, economic, political, or social changes that reduce the costs of transition ... ."[93]

Here, in a moment when the locked-in petroleum sector has been disrupted, and neither FCEV nor HEFA technology has yet become dominant and locked into the emergent petroleum diesel fuel replacement sector, this electrolysis energy integration measure could reduce the costs of transition if deployed at scale (§ 4.1). Indeed, state climate pathway analyses suggest that the need for simultaneous early deployment of electrolysis hydrogen, FCEVs, and energy storage load-balancing—and the challenge of scaling it up in time—are hard to overstate (§§ 4.1, 4.2).

Clean fuels development benefits in the HEFA Case

Converting refinery steam reforming to electrolysis during crude-to-biofuel repurposing before 2026 and at refineries to be idled and repurposed thereafter could provide electrolysis hydrogen capacities in 2025 and 2045 equivalent to the HEFA steam reforming capacities shown in Chart 5. However, HEFA refining would use this hydrogen, foreclosing its use to support early deployment of FCEVs and energy storage, and could further commit the share of future transportation illustrated in Chart 4 to liquid combustion fuel chain infrastructure.

Planned policy interventions could deploy electrolysis[58] and FCEVs[78] separately from refinery electrolysis conversions, although less rapidly without early deployment of this measure. If separate early deployment is realized at scale, this measure would enable HEFA refiners to pivot toward FCEV fueling and energy storage later. However, refinery combustion fuel share lock-in (§4.2) and competition with the separately developed clean hydrogen fueling could make that biofuel-to-ZEV-fuel transition unlikely, absent new policy intervention.

Clean fuels development benefits in the No HEFA Case

In the No HEFA Case, cellulosic residue-derived instead of HEFA biofuels would be in climate pathways,[55] and crude refinery steam reforming would be converted to electrolysis when it is idled before 2026 and in turnarounds by 2026. Instead of committing converted electrolysis hydrogen to HEFA refining as crude refining capacity is idled, it would be available for FCEVs and energy storage in the same amounts shown in Chart 5. This could fuel greater early FCEV deployment than state climate pathways assume (Chart, 2025), provide more hydrogen energy storage than in the pathways (Chart, 2045), and fuel most of the FCEV growth in the pathways through 2045 (*Id.*). These estimates from Chart 5 are based on the petroleum decline trajectory[1] underlying Chart 4, which is supported by economic drivers as well as climate constraints (§ 4.1) and assumes slower petroleum replacement through 2045 than state climate pathways (§ 4.2).

Clean fuels development benefits effectiveness

Energy integration benefits of this measure could be highly effective in supporting early deployment of zero-emission transportation during a crucial window of opportunity for replacing liquid hydrocarbon combustion fuels, and could fuel hydrogen storage as well as most zero-emission FCEV growth needs thereafter, in the No HEFA Case. In the HEFA Case, however, those benefits could be limited to an uncertain post-2030 future. These results further underscore the importance of limiting HEFA biofuel growth in state climate pathways.

4.3.3 Use of electrolysis could lessen transition impacts from future decommissioning of converted refineries

Just transitions, tailored to community-specific needs and technology-specific challenges, appear essential to the feasibility of climate stabilization.[66 94] Full just transitions analysis for communities that host refineries is beyond the scope of this report, and is reviewed in more detail elsewhere.[66 94] However, the recent idling of refining capacity, and proposals to repurpose it for HEFA biofuels, raise new transition opportunities and challenges for California communities which were identified in this analysis, affect the feasibility of climate pathways, and thus are reported here. Hydrogen plays a pivotal role in the new transition challenges and opportunities which communities that host California refineries now face.

Transition benefits in the HEFA Case

Electrolysis would enable HEFA refineries to pivot from using hydrogen for biofuel to selling it for FCEV fuel, energy storage, or both. Assuming state climate pathways that replace transportation biofuels with ZEVs[57] achieve the state goal for 100% ZEV medium- and heavy-duty vehicles by 2045,[78] this would allow HEFA refiners to transition from HEFA biofuel hydro-conversion processing while continuing uninterrupted hydrogen production at the same sites. Potential benefits would include reduced local job and tax base losses as compared with total facility closure, and eliminating the significant refinery explosion/fire risk and local air pollution impacts from HEFA hydro-conversion processing that are described in Chapter 3.

However, HEFA lock-in could occur before the prospect of such a biofuel-to-ZEV fuel transition could arise (§ 4.2). Conversions to electrolysis would lessen incentives for refiners to protect assets by resisting transition, and yet their fuel shares in emerging petroleum distillates replacement markets and incentives to protect those market shares would have grown (*Id.*).

Transition benefits in the No HEFA Case

In the No HEFA Case electrolysis hydrogen could pivot to FCEV fueling, energy storage, or both as petroleum refining capacity is idled in state climate pathways. Petroleum asset idling would be driven by economic factors that replace gasoline as well as climate constraints and thus be likely to occur (§ 4.1). Indeed, it has begun to occur (Chapter 1) and is likely to gather pace quickly (§§ 4.1, 4.2). Local job and tax base retention resulting from this hydrogen pivot in the No HEFA Case could be of equal scale as in the HEFA case. Local benefits from elimination of refinery hazard and air pollution impacts upon site transition would be from replacing petroleum refining rather than HEFA refining and would be realized upon crude refinery decommissioning rather than upon repurposed HEFA refinery decommissioning years or decades later.

Transition benefits effectiveness

Electrolysis hydrogen could have a pivotal role in just transitions for communities that host refineries. However, transition benefits of electrolysis would more likely be realized, and would be realized more quickly, in the No HEFA Case than in the HEFA Case. Realization of these potential transition benefits would be uncertain in the HEFA Case, and would be delayed as compared with the No HEFA Case.

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APPENDIX B

Karras, G., *Unsustainable Aviation Fuel*

(Karras, 2021b)

UNSUSTAINABLE AVIATION FUEL

An assessment of carbon emission and sink impacts from biorefining and feedstock choices for producing jet biofuel in repurposed crude refineries

A Natural Resources Defense Council (NRDC) Report

Prepared for the NRDC by Greg Karras, G. Karras Consulting
www.energy-re-source.com

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CONTENTS

Executive Summary

Current climate, energy and aviation policy use the term Sustainable Aviation Fuel (SAF) to mean alternatives to petroleum aviation fuel which could include seven types of biofuels and can replace up to half of petroleum jet fuel under existing aviation fuel blending limits. In practice this definition of SAF favors continued use of existing combustion fuel infrastructure to burn a mix of biofuel and petroleum. That is not a net-zero carbon climate solution in itself, and in this sense, SAF is not sustainable. Rather, the partial replacement of petroleum jet fuel with biofuel is meant to incrementally reduce emissions from the hard-to-decarbonize aviation sector and, in concert with more effective measures in other sectors, help to achieve climate stabilization goals.

A question, then, is whether the type of biofuel favored by the existing combustion fuel infrastructure will, in fact, emit less carbon than petroleum. This, the evidence suggests, is a key question for the sustainability of SAF.

Although it is but one proven technology for the production of SAF, Hydrotreated Esters and Fatty Acids (HEFA) technology is the fastest-growing type of biofuel in the U.S. today. This rapid recent and projected growth is being driven by more than renewable fuels incentives. The crucially unique and powerful driver of HEFA biofuel growth is that oil companies can protect troubled and climate-stranded assets by repurposing petroleum crude refinery hydro-conversion and hydrogen plants for HEFA jet fuel and diesel biofuels production.

Some HEFA biofuels are reported to emit more carbon per gallon than petroleum fuels. This is in part because HEFA technology depends upon and competes for limited agricultural or fishery yields of certain types—oil crops, livestock fats or fish oils—for its biomass feedstocks. Meeting increased demands for at least some of those feedstocks has degraded natural carbon sinks, causing indirect carbon emissions associated with those biofuels. And it is in part because HEFA feedstocks require substantial hydrogen inputs for HEFA processing, resulting in very substantial direct carbon emissions from fossil fuel hydrogen production repurposed for HEFA biorefining. Both processing strategies, i.e., refining configurations to target jet fuel *v.* diesel

production, and feedstock choices, e.g., choosing to process palm oil *v.* livestock fat feeds, are known factors in these direct and indirect emissions. That is important because HEFA jet fuel yield is limited, and refiners can use various combinations of feeds and processing strategies to boost jet yield with repurposed crude refining equipment. To date, however, the combined effect of these factors in strategies to boost HEFA jet fuel yield has received insufficient attention.

This report focuses on two questions about climate impacts associated with HEFA jet fuel production in repurposed crude refineries. First, could feedstocks that enable refiners to boost jet fuel yield increase the carbon dioxide emission per barrel—the carbon intensity—of HEFA refining relative to the feeds and processing strategy refiners use to target HEFA diesel yield? Second, could the acquisition of feedstocks that refiners can use to increase HEFA jet fuel yield result in comparatively more serious indirect climate impacts?

The scope of the report is limited to these two questions. Its analysis and findings are based on publicly reported data referenced herein. Data and analysis methods supporting feed-specific original research are given and sourced in an attached data and methods table.[1] Data limitations are discussed in the final chapter. This work builds on recent NRDC-sponsored research[2] which is summarized in relevant part as context above, and as referenced in following chapters.

Chapter 1 provides an overview of HEFA technology, including the essential processing steps for HEFA jet fuel production and additional options for maximizing jet fuel yield using repurposed crude refining assets. This process analysis shows that a growing fleet of HEFA refineries could, and likely would, use a combination of strategies in which the use of intentional hydrocracking (IHC) could vary widely. HEFA refiners could produce HEFA jet fuel without intentional hydrocracking (No-IHC), produce more HEFA jet fuel with IHC in the isomerization step needed for all HEFA fuels (Isom-IHC), or produce more HEFA jet fuel while shaving the increased hydrogen costs of intentional hydrocracking (Selective-IHC). The strategies chosen would be influenced by the capabilities of crude refineries repurposed for HEFA processing.

Chapter 2 reviews HEFA feedstock limitations and supply options, presents detailed data relating feedstock properties to effects on HEFA jet fuel yields and process hydrogen demand, and ranks individual feedstocks for their ability to increase HEFA jet fuel yield. Differences in chemistry among feeds result in different feed rankings for jet fuel *versus* diesel yields, different feed rankings for increased jet fuel yield among processing strategies, and different feed rankings for hydrogen demand among processing strategies. Palm oil, livestock fats, and fish oils boost jet fuel yield without intentional hydrocracking, and enable more refiners to further boost jet yield with intentional hydrocracking, which increases HEFA process hydrogen demand.

Chapter 3 describes and quantifies refining strategy-specific and feed-specific carbon dioxide (CO_2) emissions from the repurposed crude refinery steam reformers that produce hydrogen for HEFA processing. Feed-specific carbon intensity (CI) rankings for jet fuel-range feed fractions mask those for whole feed actual CI when refiners use the No-IHC process strategy. Refining CI rankings for some feeds with low *v.* high jet yields (e.g., soybean oil *v.*

menhaden fish oil) are reversed in the Selective-IHC strategy compared with the other strategies for increasing HEFA jet fuel yield. Some feeds that increase jet fuel yield have relatively higher process CI (fish oils) while others have relatively lower process CI (palm oil and livestock fats). However, palm oil and livestock fat feeds also enable the highest-CI refining strategies, and all strategies for HEFA jet fuel production result in substantially higher refining CI than the average U.S. petroleum refinery CI. This shows that HEFA jet fuel growth would increase the carbon intensity of hydrocarbon fuels processing.

Chapter 4 reviews natural carbon sinks and assesses potential carbon emission impacts from increasing production of the specific food system resources HEFA refiners can use as feedstocks. Palm oil, livestock, and fisheries production emit from these carbon sinks. Present assessments confirm this "indirect" impact of palm oil biofuels, but suggest livestock fat and fish oil biofuels have relatively low feed production emissions due to the assumption that biofuel demand will not expand livestock production or fisheries catch. Some also assume U.S. policies that discourage palm oil biofuels prevent palm oil expansion to fill in for other uses of biomass biofuels displace. Those assumptions, however, are based on historical data, when biofuels demand was far below total production for the type of biomass HEFA refiners can process. HEFA feedstock demand could far exceed total current U.S. production for all uses of that biomass type—including food and fuel—if HEFA jet fuel replaces as little as 18 percent of current U.S. jet fuel consumption.

With HEFA jet fuel growth to replace 18 percent of U.S. jet fuel, world livestock fat and fish oil production could supply only a fraction of U.S. HEFA feedstock demand unless that demand boosts their production, with consequent indirect carbon impacts. Palm oil production could expand to fill other uses for livestock fat and other plant oils which the increased U.S. biofuel demand would displace. Intensified and expanded production of soybean and other oil crops with relatively high indirect carbon impacts would likely be necessary, in addition, to supply the total demand for both food and fuel. Further, given refiner incentives to repurpose climate-stranded crude refining assets, plausible U.S. HEFA growth scenarios by mid-century range above 18 percent and up to 39 percent of U.S. jet fuel replacement with HEFA jet fuel.

Thus, data and analysis in Chapter 4 suggest the potential for significant indirect carbon emission impacts associated with the mix of HEFA jet fuel feedstocks that could meet plausible future SAF demand, and that high-jet yield feeds could contribute to or worsen these impacts.

Crucially, causal factors for these impacts would be inherent and mutually reinforcing. HEFA technology repurposed from crude refineries can process only feedstocks that are co-produced from food resources, it requires large hydrogen inputs that boost refining emissions to marginally improve its low jet fuel yield, and even then, it could require more than two tons of carbon-emitting feedstock production per ton of HEFA jet fuel produced.

Findings and takeaways from this work follow below.

Findings and Takeaways

Finding 1. Hydrotreated Esters and Fatty Acids (HEFA) biofuel technology has inherent limitations that affect its potential as a sustainable aviation fuel: low jet fuel yield on feedstock, high hydrogen demand, and limited sustainable feedstock supply.

Takeaway Climate-safe plans and policies will need to prioritize alternatives to petroleum jet fuel combustion which do not have known sustainability limitations.

Finding 2. Switching HEFA feedstocks to target increased jet fuel yield could increase the carbon intensity—CO_2 emitted per barrel feed—of HEFA refining, compared with targeting HEFA diesel yield. HEFA refining carbon intensity could increase in 80 percent of plausible feed switch and processing combinations targeting jet fuel. Direct emission impacts could be significant given that the carbon intensity of HEFA refining substantially exceeds that of U.S. petroleum refining.

Takeaway Environmental impact assessments of proposed HEFA projects will need to address potential emissions from future use of HEFA refineries to maximize jet fuel production, and assess lower emitting alternatives to repurposing existing high-carbon refinery hydrogen plants.

Finding 3. One of three feeds that could boost HEFA jet fuel yield causes carbon emissions from deforestation for palm plantations, and the other two cannot meet potential HEFA feedstock demand without risking new carbon emissions from expanded livestock production or fisheries depletion. These indirect impacts could be significant given that feedstock demand for replacing only a small fraction of current U.S. jet fuel with HEFA jet fuel would exceed total U.S. production of HEFA feedstocks biomass—biomass which now is used primarily for food.

Takeaway Before properly considering approvals of proposed HEFA projects, permitting authorities will need to assess potential limits on the use of feedstocks which could result in significant climate impacts.

Finding 4. Natural limits on total supply for the type of feedstock that HEFA technology can process appear to make replacing any significant portion of current petroleum jet fuel with this type of biofuel unsustainable.

Takeaway Sustainable aviation plans will need to consider proactive and preventive limits on HEFA jet fuel, in concert with actions to accelerate development and deployment of sustainable, climate-safe alternatives.

1. How would refiners rebuild for HEFA jet fuel production?

Oil companies can repurpose existing fossil fuel hydrogen plants, hydrocrackers, and hydrotreaters at their petroleum refineries to produce jet fuel and diesel biofuels using a technology called hydrotreating esters and fatty acids (HEFA). "Hydrotreating" means a hydro-conversion process: the HEFA process reacts biomass with hydrogen over a catalyst at high temperatures and pressures to form hydrocarbons and water. "Esters and fatty acids" are the type of biomass this hydro-conversion can process: the triacylglycerols and fatty acids in plant oils, animal fats, fish oils, used cooking oils, or combinations of these biomass lipids.[1]

HEFA processing requires a sequence of steps, performed in separate hydro-conversion reactors, to deoxygenate and isomerize (restructure) the lipids feedstock, and very substantial hydrogen inputs for those process steps, in order to produce diesel and jet fuels.[2]

One problem with using HEFA technology for Sustainable Aviation Fuel (SAF) is that these hydrodeoxygenation and isomerization steps alone can convert only a fraction of its feedstock into jet fuel—as little as 0.128 pounds of jet fuel per pound of soybean oil feed.[3] Intentional hydrocracking can boost HEFA jet fuel yield to approximately 0.494 pounds per pound of feed,[3] however, that requires even more hydrogen, and can require costly additional refining capacity. This chapter describes the range of processing strategies that refiners could use to increase HEFA jet fuel yields from their repurposed crude refineries.

1.1 Step 1: Hydrodeoxygenation (HDO) of jet fuel (and diesel) hydrocarbons

HEFA processing produces diesel and jet fuels from the hydrocarbon chains of fatty acids. In all HEFA feedstocks, fatty acids are bound in triacylglycerols that contain substantial oxygen, and various numbers of carbon double bonds. To free the fatty acids and make fuels that can burn like petroleum diesel and jet fuel from them, that oxygen must be removed from the whole feed. This first essential step in HEFA processing is called hydrodeoxygenation (HDO).

HDO reaction chemistry is complex, as reviewed in more detail elsewhere,[2] and its intended reactions all consume hydrogen by forcing it into the feedstock molecules. Process reactions insert hydrogen to free fatty acids from triacylglycerols ("depropanation") and to remove oxygen by bonding it with hydrogen to form water ("deoxygenation"). And along with those reactions, still more hydrogen bonds with the carbon chains to "saturate" the carbon double bonds in them. These reactions proceed at high temperatures and pressures in the presence of a catalyst to yield the intended HDO products: deoxygenated hydrocarbon chains which can be further processed to make diesel and jet fuels.

1.2 Step 2: Isomerization of jet fuel and diesel hydrocarbons

Isomerization restructures the saturated straight-chain hydrocarbons produced by HDO, which are too waxy to burn well or safely in diesel or jet engines, by turning these straight-chain hydrocarbons into their branched-chain isomers. This is the second essential HEFA process step.

Like HDO, isomerization reactions are complex, proceed at high temperatures and pressures in the presence of a catalyst, and require substantial hydrogen inputs.[2] However, isomerization process reactions, conditions, and catalysts differ substantially from those of HDO and, instead of consuming the hydrogen input as in HDO, most of the hydrogen needed for isomerization can be recaptured and recycled.[2] These differences have so far required a separate isomerization processing step, performed in a separate process reactor, to make HEFA diesel and jet fuel.

1.3 Additional option of intentional hydrocracking (IHC)

Hydrocracking breaks ("cracks") carbon bonds by forcing hydrogen between bonded carbon atoms at high temperature and pressure. This cracks larger hydrocarbons into smaller ones. It is an unwanted side reaction in HDO and some isomerization processing since when uncontrolled, it can produce compounds too small to sell as either diesel or jet fuel. *Intentional* hydrocracking (IHC) uses specialized catalysts and process conditions different from those required by HDO to crack HDO outputs into hydrocarbons in the jet fuel range.

Thus, while HEFA refiners can make jet fuel with HDO and isomerization alone (No-IHC), they could make more jet fuel by adding IHC to their processing strategy. Adding IHC for the HDO output can boost jet fuel yield to approximately 49.4 percent of HEFA feedstock mass (49.4 wt.%).[3] This boost is important, compared with No-IHC jet fuel yield of approximately 12.8 wt.% on soybean oil,[3] the most abundant HEFA feedstock produced in the U.S.[2] However, hydrocrackers are expensive to build for refineries that do not already have them,[4] and IHC increases demand for hydrogen plant production capacity by approximately 1.3 wt.% on feed (800 cubic feet of H_2/barrel).[2,3] New capacity for additional hydrogen production is also costly to refiners that cannot repurpose existing capacity. HEFA refiners that choose the IHC option to maximize jet fuel yield might choose one processing strategy to minimize new hydrocracking capacity cost, or another processing strategy to minimize new hydrogen capacity cost.

1.3.1 IHC in isomerization process units

Hydrocracking and isomerization can be accomplished in a repurposed crude refinery hydrocracker, given the necessary retooling and catalyst for HEFA HDO output processing.[2] Thus, a crude refinery with sufficient existing hydrocracking and hydrogen capacity for the whole HEFA feed stream it plans to process could repurpose that equipment for IHC in the isomerization step of its repurposed HEFA process configuration. This "Isom-IHC" processing strategy would allow that refiner to maximize HEFA jet fuel yield without the capital expense of building a new hydrocracker. However, combining intentional hydrocracking in isomerization, which is required for all HEFA fuels, cracks the entire output from the HDO step, incurring the 800 cubic feet of hydrogen per barrel cost increment on the entire HEFA feed. If a refiner lacks the existing hydrogen capacity, Isom-IHC could entail building new hydrogen plant capacity.

1.3.2 Selective IHC in separate hydrocracking process units

HEFA refiners separate the components of their HDO and isomerization outputs to re-run portions of the feed through those processes and to sell HEFA diesel and jet fuel as separate products. That distillation, or "fractionation," capacity could be used to separate the jet fuel produced by HDO and isomerization processing from their hydrocarbons output, and feed only those hydrocarbons outside the jet fuel range to a separate intentional hydrocracking unit. This "Selective-IHC" processing strategy could increase jet fuel yield while reducing IHC hydrogen consumption, and new hydrogen plant costs, compared with those of the Isom-IHC strategy. However, it would not eliminate the hydrogen production cost of IHC, and more importantly for refiners that lack the existing hydrocracking capacity before repurposing their crude refineries, it would entail building expensive new hydrocrackers.

1.4 <u>Three potential HEFA jet fuel processing strategies</u>

HEFA feedstock supply limitations,[2] differences in hydrogen production and hydrocracking capacities among U.S. refineries,[5] and the differences between processing strategies described above suggest the broad outlines of a prospective future HEFA jet fuel refining fleet. Refiners that can repurpose sufficient capacity could maximize HEFA jet fuel yield using IHC strategies. The fleet-wide mix would be influenced initially by whether existing hydrocracking or hydrogen production capacity would limit total production by each refinery to be repurposed. Later, the relative costs of hydrogen production *v.* hydrocracking could affect the mix of Selective-IHC *v.* Isom-IHC in the mid-century HEFA refining fleet.

Refiners that lack sufficient capacity for IHC could repurpose for the No-IHC strategy and coproduce HEFA jet fuel along with larger volumes of HEFA diesel. Then, increasing costs of the much higher feed volume needed per gallon of HEFA jet fuel yield from the No-IHC strategy could limit this strategy to a small portion of the refining fleet by mid-century. Declining HEFA diesel demand, as electric and fuel cell vehicles replace diesel vehicles, could further drive this this limitation of the No-IHC processing strategy. However, refiners that do not use intentional hydrocracking could seek to boost HEFA jet fuel yield in another way.

2. Can refiners make more HEFA jet fuel from some feedstocks than from others?

HEFA biofuel technology is limited to a particular subset of world biomass supply for its feedstock. Despite that limitation, however, differences among these lipid feeds could affect both HEFA processing and jet fuel yield. This chapter assesses individual HEFA feedstocks for potential differences in HEFA processing and HEFA jet fuel yield.

Results reveal strong interactions between feedstock and processing configuration choices. In essential HEFA process steps, feed choices affect jet fuel yield and hydrogen demand, both of which affect options to further boost jet yield with intentional hydrocracking. Both feedstock and processing choices can increase hydrogen demand, which can affect processing to boost jet fuel yield where hydrogen supply is limited. Feed-driven and process strategy-driven impacts on hydrogen demand overlap, however, feed rankings for hydrogen differ from those for jet yield, and differ among processing configurations. From the lowest to highest impact combinations of feedstock and processing options, jet fuel yield and hydrogen demand increase dramatically.

Palm oil, livestock fat, and fish oil have relatively high jet fuel yields without intentional hydrocracking, and relatively high potentials to enable further boosting jet fuel yields with intentional hydrocracking (IHC).

2.1 <u>HEFA feedstock limitations and supply options</u>

HEFA biofuel technology relies on the fatty acids of triacylglycerols in biomass lipids for its feedstocks, as described in Chapter 1. Sources of these in relevant concentrations and quantities are limited to farmed or fished food system lipids resources. Among its other problems, which are addressed in a subsequent chapter, this technological inflexibility limits feedstock choices for refiners seeking to increase HEFA jet fuel yield.

Historically used lipid biofuel feedstock supplies include palm oil, soybean oil, distillers corn oil, canola (rapeseed) oil, and cottonseed oil among the significant HEFA oil crop feeds; livestock fats, including beef tallow, pork lard, and poultry fats; and fish oils—for which we analyze data on anchovy, herring, menhaden, salmon, and tuna oils.[1] Additionally, though it is a secondary product from various mixtures of these primary lipid sources, and its supply is too limited to meet more than a small fraction of current HEFA demand,[2] we include used cooking oil (UCO) in our analysis.[1]

2.2 Feedstock properties that affect HEFA jet fuel production

2.2.1 Feedstock carbon chain length

Jet fuel is a mixture of hydrocarbons that are predominantly in the range of eight to sixteen carbon atoms per molecule. In fuel chemistry shorthand, a hydrocarbon with 8 carbons is "C8" and one with 16 carbons is "C16," so the jet fuel range is C8–C16. Similarly, a fatty acid chain with 16 carbons is a C16 fatty acid. Thus, since fuels produced by the essential HEFA process steps—hydrodeoxygenation (HDO) and isomerization—reflect the chain lengths of fatty acids in the feed,[2] the ideal HEFA jet fuel feed would be comprised of C8–C16 fatty acids. But there is no such HEFA feedstock.

In fact, the majority of fatty acids in HEFA lipids feeds, some 53% to 95% depending on the feed, have chain lengths outside the jet fuel range.[1] This explains the low jet fuel yield problem with relying on HEFA technology for Sustainable Aviation Fuel (SAF) described in Chapter 1. However, that 53–95% variability among feeds also reveals that refiners could make more HEFA jet fuel from some HEFA feedstocks than from others.

2.2.2 Feedstock-driven process hydrogen demand

Options to increase HEFA jet fuel yield using intentional hydrocracking could be limited by hydrogen supplies available to refiners, and HDO, an essential HEFA process step, consumes hydrogen to saturate carbon double bonds in feeds and remove hydrogen from them (Chapter 1). HDO accounts for the majority of HEFA process hydrogen demand, and some HEFA feeds have more carbon double bonds, somewhat higher oxygen content, or both, compared with other HEFA feeds.[2] Thus, some HEFA feeds consume more process hydrogen, and thereby have more potential to affect jet fuel yield by limiting high-yield processing options, than other feeds.

2.3 Ranking HEFA feedstocks for jet fuel production

2.3.1 Effects on HDO yield

Table 1 summarizes results of our research for the chain length composition of fatty acids in HEFA feedstocks.[1] This table ranks feeds by their jet fuel range (C8–C16) fractions. Since fuels produced by the essential HDO and isomerization steps in HEFA processing reflect the chain lengths of HEFA feeds, the volume percentages shown in Table 1 represent potential jet fuel yield estimates for the processing strategy without intentional hydrocracking (No-IHC).

Table 1. Chain length* composition of fatty acid chains in HEFA feedstocks, ranked by jet fuel fraction.

	Jet fuel fraction (C8–C16) (volume % on whole feed)	Diesel fraction (C15–C18) (vol. %)	> C16 (vol. %)	>C18 (vol. %)
Palm oil	46.5	95.6	53.5	0.5
Menhaden oil	42.3	59.8	57.7	31.2
Tallow fat	33.3	95.2	66.7	0.4
Herring oil	32.7	49.3	67.3	42.7
Poultry fat	32.7	98.1	67.3	1.1
Anchovy oil	32.6	52.2	67.4	40.9
Tuna oil	31.5	48.9	68.5	44.5
Lard fat	30.0	96.5	70.0	2.1
Salmon oil	27.5	49.7	72.5	44.0
UCO 10th P.*	26.8	97.9	73.2	1.1
Cottonseed oil	25.7	98.7	74.3	0.4
Corn oil (DCO)*	13.6	98.9	86.4	1.1
UCO 90th P.*	12.9	99.2	87.1	0.8
Soybean oil	11.7	99.5	88.3	0.4
Canola oil	4.8	96.8	95.2	3.1
Yield-wtd. Average	**26.3**	**97.4**	**73.7**	**1.0**

***Cx:** fatty acid chain of x carbons. **UCO:** used cooking oil. **10th P.:** 10th Percentile. **DCO:** Distillers corn oil. Data from Table 8, except world yield data by feed type for yield-weighted average shown from Table 7. Percentages do not add; fractions overlap.

Potential feed-driven effects on jet fuel yield shown in Table 1 range tenfold among feeds, from approximately 4.8% on feed volume for canola oil to approximately 46.5% for palm oil. For context, since supplies of some feeds shown are relatively low, it may be useful to compare high jet fuel yield feeds with soybean oil, the most abundant HEFA feed produced in the U.S.[2] Palm oil, the top ranked feed for jet fuel yield, could potentially yield nearly four times as much HEFA jet fuel as soybean oil, while menhaden fish oil and tallow might yield 3.6 times and 2.8 times as much jet fuel as soy oil, respectively. Again, this is for the No-IHC processing strategy.

2.3.2 Effects on IHC strategies yields

Feed-driven jet fuel yield effects could allow intentional hydrocracking (IHC) to further boost HEFA jet fuel yield, depending on the IHC processing strategy that refiners may choose. At 49.4 wt.% on feed (Chapter 1), or approximately 58 volume percent given the greater density of the feed than the fuel, IHC jet fuel yield exceeds those of the feed-driven effects shown in Table 1. But IHC adds substantially to the already-high hydrogen demand for essential HEFA process steps (Chapter 1). In this context, the eight highest-ranked feeds for jet fuel yield in Table 1 may allow a refiner without the extra hydrogen supply capacity to use IHC on its entire feed to use Selective-IHC on 53.5% to 70% of its feed. This indirect effect of feed-driven jet fuel yield on process configuration choices has the potential to further boost HEFA jet fuel yield.

Direct feedstock-driven effects on process hydrogen demand, which can vary by feed as described above, must be addressed along with this indirect effect. *See* Table 2 below.

Table 2. Hydrogen demand for hydrodeoxygenation (HDO) of HEFA feedstocks, grouped by HDO jet fuel and diesel hydrocarbon yields. Data in kilograms hydrogen per barrel of feed fraction (kg H_2/b)

Feedstock grouping	Jet fraction (C8–C16)[a]		Diesel fraction (C15–C18)[a]		Longer chains (> C18)[a b]	
	HDO kg/b[c]	Sat kg/b[d]	HDO kg/b[c]	Sat kg/b[d]	HDO kg/b[c]	Sat kg/b[d]
High jet/high diesel						
Palm oil	4.38	< 0.01	4.77	0.64	3.52	0.15
Tallow fat	4.53	0.14	4.70	0.62	3.62	0.19
Poultry fat	4.58	0.25	5.04	0.92	3.99	0.67
Lard fat	4.43	0.11	4.84	0.75	5.39	1.68
UCO (10th Pc.)	4.52	0.20	5.02	0.92	4.30	0.75
Cottonseed oil	4.30	0.02	5.47	1.34	3.51	0.16
High jet/low diesel						
Menhaden oil	4.72	0.28	5.07	0.85	8.64	4.83
Herring oil	4.77	0.30	5.09	0.89	6.11	2.52
Anchovy oil	4.72	0.28	5.22	1.02	8.07	4.31
Tuna oil	4.67	0.24	4.81	0.64	8.06	4.34
Salmon oil	4.51	0.09	5.18	1.01	7.99	4.27
Low jet/high diesel						
Corn (DCO) oil	4.27	0.01	5.60	1.48	4.87	1.38
UCO (90th Pc.)	4.35	0.09	5.56	1.45	3.38	0.00
Soybean oil	4.28	0.01	5.70	1.59	3.31	0.00
Canola oil	4.35	0.07	5.45	1.37	3.98	0.55

a. Feedstock component fractions based on carbon chain lengths of fatty acids in feeds. **b.** Fatty acid chains with more than 18 carbons (> C18), which might be broken into two hydrocarbon chains in the jet fuel range (C8–C16) by intentional hydrocracking (IHC). **c.** HDO: hydrodeoxygenation; hydrogen consumed in HDO reactions, including saturation. **d.** Sat: saturation, H_2 needed to saturate carbon double bonds in the feedstock component, included in HDO total as well and broken out here for comparisons between types of feeds. *See* Table 8 for details of data, methods, and data sources. Note that fatty acids with 15–16 carbons (C15–C16) are included in both the jet fuel and the diesel fuel ranges. **UCO:** Used cooking oil, a highly variable feed; the 10th and 90th percentiles of this range of variability are shown.

2.3.3 Effects on process hydrogen demand

Table 2 shows process hydrogen demand for HDO, and the portion of HDO accounted for by saturation of carbon double bonds, for fractions of each feedstock. The important detail this illustrates is that saturation of carbon double bonds—especially in the larger-volume diesel fraction and, for fish oils, the longer chain fraction—explains most of the differences in direct effects on hydrogen demand among feeds. At less than 1% to more than half of HDO hydrogen demand, saturation drives differences in hydrogen demand among feed fractions (Table 2). Further, these differences peak in the diesel and longer chain fractions of feeds (*Id.*), and the combined volumes of these diesel and longer chain fractions are both high for all feeds and variable among feeds (Table 1).

Since HDO is an essential step in all HEFA processing strategies (Chapter 1), this evidence that process hydrogen demand varies among feeds because of the processing characteristics of whole feeds means we can compare hydrogen demand across processing strategies based on whole feeds. Table 3 shows results from this comparison across processing strategies.

Table 3. Hydrogen demand in the no intentional hydrocracking (No-IHC), Selective IHC and Isom-IHC processing strategies by feed grouping and feed. ***kg H_2/b:*** *kilograms hydrogen/barrel whole feed*

Feedstock grouping	No-IHC [a] (kg H_2/b)	Selective-IHC [b] (kg H_2/b)	Isom-IHC [c] (kg H_2/b)
High jet/high diesel			
Palm oil	4.79	5.79	6.60
Tallow fat	4.71	6.11	6.70
Poultry fat	5.03	6.28	6.85
Lard fat	4.85	6.13	6.65
UCO (10th P.)	5.01	6.37	6.83
Cottonseed oil	5.44	6.84	7.28
High jet/low diesel			
Menhaden oil	6.18	7.30	8.02
Herring oil	5.50	6.76	7.33
Anchovy oil	6.37	7.67	8.23
Tuna oil	6.29	7.62	8.16
Salmon oil	6.40	7.78	8.25
Low jet/high diesel			
Corn (DCO) oil	5.58	7.19	7.42
UCO (90th P.)	5.55	7.17	7.39
Soybean oil	5.68	7.33	7.52
Canola oil	5.40	7.16	7.24
Feed-wtd. Average	5.24	6.62	7.07

a. Intentional hydrocracking (IHC) is not used. **b.** Intentional hydrocracking (IHC) is selective because in this strategy HDO output is separately isomerized, and only the non-jet fuel hydrocarbons from HDO are fed to IHC. **c.** Isomerization and IHC are accomplished in the same process step in this strategy; all HDO output, including the jet fuel fraction, is fed to intentional hydrocracking in this strategy. *See* Table 8 for details of data, methods, and data sources;[1] Table 7 for world feed data used to derive feed-weighted averages. **UCO:** Used cooking oil, a highly variable feed; 10th and 90th percentiles of range shown.

2.3.4 Interactions between feedstock and processing choices

Feedstock and process strategy choices combined can impact HEFA process hydrogen demand dramatically (Table 3). As expected, IHC increases hydrogen demand for all feeds, however, feed-driven and process strategy-driven effects overlap. The maximum feed-driven impact in the No-IHC strategy (6.40 kg H_2/b) exceeds the minimum (5.79 kg H_2/b) in the Selective-IHC strategy (*Id.*). Similarly, the maximum feed-driven impact in the Selective-IHC strategy (7.78 kg H_2/b) exceeds the minimum (6.60 kg H_2/b) in the Isom-IHC strategy (*Id.*). Hydrogen demand increases by approximately 75% from the lowest impact (4.71 kg H_2/b) to the highest impact (8.25 kg H_2/b) combination of feedstock and processing strategy (*Id.*).

Feed rankings for hydrogen demand differ from feed rankings for jet fuel yield (tables 1, 3). Palm oil ranks at the top for jet fuel yield and at or near the bottom for hydrogen demand while in contrast, fish oils are among the highest ranked feeds for both jet yield and hydrogen demand. Livestock fats are among the highest ranked feeds for jet fuel yield and among the lowest ranked feeds for hydrogen demand. The lowest ranked feeds for jet fuel yield, soybean and canola oils, are medium-ranked to high-ranked feeds for hydrogen demand.

Relatively lower hydrogen demand for palm oil and livestock fats across the columns in Table 3 further illustrates how interactions of feedstock and processing strategies can contribute to increased jet fuel yields. For example, the relative Isom-IHC hydrogen demand reduction achievable by switching from soybean oil to tallow (-0.82 kg/b; -10.9%) or from soybean oil to palm oil (-0.92 kg/b; -12.2%) can help to support the highest jet fuel yield processing strategy in situations where refinery hydrogen production capacity is marginally limited.

Results in Table 3 also reveal that some feedstocks switch rankings between the Selective-IHC strategy and other processing strategies. In one example, canola oil feedstock demands more hydrogen than cottonseed oil feedstock for Selective-IHC but slightly less than cottonseed oil for the No-IHC and Isom-IHC strategies (Table 3). This corresponds to the greater fraction of canola oil than cottonseed oil sent to intentional hydrocracking for the Selective-IHC strategy (*see* Table 1, > C16 vol. %).

Another example: Only some 57.7% of the total Menhaden oil feed volume goes to intentional hydrocracking for Selective-IHC, as compared with 88.3% of the soybean oil feed (*Id.*). Consequently, Menhaden oil demands less hydrogen than soybean oil for Selective-IHC but more hydrogen than soybean oil for the other processing strategies (Table 3).

Putting these direct and indirect feed-driven effects together, consider switching from soybean oil to tallow for Selective-IHC at a 50,000 to 80,000 b/d refinery—which is in the range of projects now proposed in California.[2] The direct effect on HDO from this soy oil-to-tallow switch, shown in the No-IHC column of Table 3 (-0.97 kg H_2/b), carries over to Selective-IHC. The indirect effect sends 21.6% less of the total tallow feed to hydrogen-intensive cracking for Selective IHC than that of soy oil (Table 1, > C16 fractions), further boosting hydrogen savings from the switch to -1.22 kg/b on total feed (Table 3). At feed rates of 50,000–80,000 b/d, this might save the refiner construction and operating costs for 61,000 to 97,600 kg/d of hydrogen capacity. Expressed as volume in millions of standard cubic feet per day (MMSCFD), that is the equivalent of a 24 to 38 MMSCFD hydrogen plant.

At the same time that switching from soy with No-IHC to tallow with Selective-IHC could enable the higher-yield processing strategy, however, net process hydrogen demand would increase by 0.43 kg/b (Table 3), an increase in this example of 8.4 to 13.5 MMSCFD.

Thus, examining feed and processing interactions reveals that switching to feeds with higher jet-range fractions, lower HDO hydrogen demand, or both enables refiners with limited hydrogen supplies to use intentional hydrocracking and thereby further boost jet fuel yields. More broadly, these results show refiners can make more HEFA jet fuel from some feedstocks than from others, but that doing so could result in substantially increased hydrogen demand for some combinations of feedstock and processing choices.

3. Does switching from one HEFA feedstock to another change processing carbon intensity differently when refiners target jet fuel instead of diesel production?

Switching feedstocks and production targets can affect the per-barrel emissions—the *carbon intensity*—of HEFA refining dramatically. The vast majority of direct CO_2 emission from HEFA refining emits from petroleum refinery steam reformers that refiners repurpose to supply HEFA process hydrogen demand.[2] The reformer emissions further increase with increasing hydrogen production.[2] As shown in Chapter 2, refiners could switch feeds to boost HEFA jet fuel yield in ways that increase refinery hydrogen demand differently compared with targeting HEFA diesel yield. This chapter evaluates the carbon intensity (CI) impacts of HEFA refining that could result from targeting HEFA jet fuel yield instead of diesel yield, and weighs their significance against the CI of petroleum refining.

3.1 CO_2 co-production and emission from hydrogen production by steam reforming

3.1.1 How steam reforming makes hydrogen

Steam reforming is a fossil fuel hydrogen production technology that co-produces CO_2. The process reacts a mixture of superheated steam and hydrocarbons over a catalyst to form hydrogen and CO_2. Hydrocarbons used include methane from natural gas, and it is often called steam methane reforming (SMR), but crude refiners use hydrocarbon byproducts from refining such as propane, along with methane from purchased natural gas, as feeds for the steam reformers that they could repurpose for HEFA processing.

3.1.2 How steam reforming emits CO_2

Both its CO_2 co-product and CO_2 formed in its fuel combustion emit from steam reforming. An energy-intensive process, steam reforming burns fuel to superheat process steam and feed, and burns more fuel for energy to drive pumps and support process reactions. Steam reforming fuel combustion emissions are reformer-specific and vary by plant. Based on verified permit data for 11 San Francisco Bay Area crude refinery steam reforming plants, we estimate median fuel combustion emissions of approximately 3.93 grams of CO_2 emitted per gram of hydrogen produced (g CO_2/g H_2), conservatively assuming methane fuel.[2] Co-product emissions are larger still, and vary by feed, with approximately 5.46 g CO_2/g H_2 emitting from methane feed and 6.56 g CO_2/g H_2 emitting from propane feed.[2] The coproduct and combustion emissions are additive.

3.1.3 Steam reforming CO_2 emission estimate

HEFA refinery steam reforming can be expected to use a feed and fuel mix that includes the propane byproduct from the process reactions discussed in Chapter 1 and natural gas methane. Based on process chemistry we conservatively assume 79% methane/21% propane feed with 100% methane fuel. From these figures we estimate typical HEFA steam reforming emissions of approximately 9.82 g CO_2/g H_2. This estimate is for repurposed crude refinery steam reformers, which are aging and may not be as efficient as newer steam reformers.[2] For context, however, our estimate is within 2.5% of a recent independent estimate of median emissions from newer merchant steam methane reforming plants, when compared on a same-feed basis.[2]

Thus, repurposed refinery steam reforming emits CO_2 at nearly ten times its weight in hydrogen supplied. With the high hydrogen demand for HEFA processing shown in Chapter 2, that is a problem. Since steam reforming emissions increase with increased production to meet increased hydrogen demand, the refining CI values reported below are based on the emission factor described above (9.82 g CO_2/g H_2) and the hydrogen demand data from Chapter 2.

3.2 <u>Feedstock effects on CI resulting from HDO hydrogen demand</u>

Hydrodeoxygenation (HDO) is an essential step, and is the major hydrogen consuming step, in all HEFA processing strategies (chapters 1 and 2). The data in Table 4 represent the HEFA processing strategy that uses HDO without intentional hydrocracking (No-IHC).

3.2.1 Feedstock HDO chemistry impact on HEFA refining CI

Table 4 shows effects of feedstock HDO chemistry on HEFA steam reforming emissions. Steam reforming-driven CI (kg/b: kg CO_2 per barrel feed) is substantially higher for whole feeds than for their jet fuel fractions. This is because the non-jet fractions need more hydrogen to saturate carbon double bonds and their combined volumes are larger than that of the jet fuel fraction (tables 1 and 2). Further, the extent of these differences between fractions varies among feeds (*Id.*). This is why feeds change ranks between the columns in Table 4. For example, the jet fuel fraction of palm oil has higher CI than that of soybean oil even though the whole feed data show that soybean oil is a higher CI feed. This variability among feed fractions also is why fish oil CI is high for both the jet fraction and the whole feed.

3.2.2 Need to account for whole feed impact

Does Table 4 show that palm oil could be a higher refining CI feed than soybean oil? No. Since the HDO step is essential for removing oxygen from the whole feed to co-produce both HEFA jet fuel and HEFA diesel, choosing any feed results in the CI impact of that whole feed.

Table 4. Hydrogen steam reforming emissions associated with the jet fuel fraction *v.* whole HEFA feeds in the HDO (No IHC) refining strategy; comparison of feed ranks by emission rate.

Jet fuel fraction (C8–C16)		Whole feed (≥ C8)	
Feed (rank)	CO_2 (kg/b feed)	Feed (rank)	CO_2 (kg/b feed)
Herring oil	46.8	Salmon oil	62.8
Menhaden oil	46.4	Anchovy oil	62.5
Anchovy oil	46.4	Tuna oil	61.7
Tuna oil	45.9	Menhaden oil	60.7
Poultry fat	45.0	Soybean oil	55.8
Tallow fat	44.5	Distillers corn oil	54.8
UCO (10th Percentile)	44.4	UCO (90th Percentile)	54.4
Salmon oil	44.3	Herring oil	54.0
Lard fat	43.5	Cottonseed oil	53.4
Palm oil	43.0	Canola oil	53.1
Canola oil	42.7	Poultry fat	49.4
UCO (90th Percentile)	42.7	UCO (10th Percentile)	49.2
Cottonseed oil	42.2	Lard fat	47.6
Soybean oil	42.0	Palm oil	47.1
Distillers corn oil	41.9	Tallow fat	46.2

C8–C16: fatty acid chains with 8 to 16 carbon atoms. **≥ C8:** fatty acid chains with 8 or more carbon atoms. **Menhaden:** a fish. **UCO:** used cooking oil, a variable feed; 10th and 90th percentiles shown. Data from Table 2 at 9.82 g CO_2/g H2 steam reforming.

While the jet fuel fraction data in this table helps to inform why feed quality impacts refining CI, we need to account for those CI impacts of whole feeds shown in Table 4.

3.2.3 High-jet feeds can increase or decrease HDO-driven CI

HDO-driven CI findings for whole feeds reveal mixed CI results for high-jet fuel yield feedstocks in No-IHC processing. Fish oils rank highest for steam reforming-driven CI while livestock fats and palm oil rank lowest (Table 4). Thus, for this processing strategy, switching feeds to boost jet fuel yield can increase or decrease refining CI. However, No-IHC also is the processing strategy that HEFA refiners use to maximize diesel yield rather than jet fuel yield. Feedstock quality interacts with other processing choices in different ways that could further boost HEFA refining CI along with jet fuel yield, as shown below.

3.3 Feedstock effects on CI resulting from Selective-IHC hydrogen demand

3.3.1 Process strategy impact of high-jet feeds

High jet yield feeds result in less input to Selective-IHC, enabling marginally hydrogen-limited refiners to further boost jet fuel yield via Selective-IHC, but this requires additional hydrogen (chapters 1 and 2). Intentional hydrocracking (IHC) thus increases hydrogen steam reforming rates and emissions, increasing refining CI for all feeds, as shown in Table 5. This impact overlies the HDO impact, so that feed CI values overlap between columns. For example, the tuna oil No-IHC CI (61.7 kg/b) exceeds the tallow Selective-IHC CI (60.0 kg/b), and the anchovy oil Selective-IHC CI (75.3 kg/b) exceeds the soy oil Isom-IHC CI (73.9 kg/b).

Table 5. Hydrogen steam reforming emissions from the No-IHC, Selective-IHC, and Isomerization IHC refining strategies: comparisons of whole HEFA feed ranks by emission rate.

No-IHC		Selective-IHC		Isomerization-IHC	
Feed (rank)	(kg CO_2/b)	Feed (rank)	(kg CO_2/b)	Feed (rank)	(kg CO_2/b)
Salmon oil	62.8	Salmon oil	76.4	Salmon oil	81.0
Anchovy oil	62.5	Anchovy oil	75.3	Anchovy oil	80.8
Tuna oil	61.7	Tuna oil	74.8	Tuna oil	80.1
Menhaden oil	60.7	Soybean oil	72.0	Menhaden oil	78.8
Soybean oil	55.8	Menhaden oil	71.6	Soybean oil	73.9
Corn oil–DCO	54.8	Corn oil-DCO	70.6	Corn oil-DCO	72.8
UCO 90th P.	54.4	UCO 90th P.	70.4	UCO 90th P.	72.6
Herring oil	54.0	Canola oil	70.3	Herring oil	72.0
Cottonseed oil	53.4	Cottonseed oil	67.2	Cottonseed oil	71.5
Canola oil	53.1	Herring oil	66.4	Canola oil	71.1
Poultry fat	49.4	UCO 10th P.	62.5	Poultry fat	67.2
UCO 10th P.	49.2	Poultry fat	61.7	UCO 10th P.	67.1
Lard fat	47.6	Lard fat	60.2	Tallow fat	65.7
Palm oil	47.1	Tallow fat	60.0	Lard fat	65.3
Tallow fat	46.2	Palm oil	56.9	Palm oil	64.8

IHC: Intentional hydrocracking. **No-IHC:** CO_2 from hydrodeoxygenation (HDO). **Selective-IHC:** CO_2 from HDO plus IHC of HDO output hydrocarbons > C16. **Isomerization-IHC:** CO_2 from HDO plus IHC of all HDO output (> C8). **Menhaden:** a fish. **UCO:** used cooking oil, 10th, 90th percentiles shown. **DCO:** distillers corn oil. Figures shown exclude emissions associated with H_2 losses, depropanation, and inadvertent cracking. Data from Table 3 at 9.82 g CO2/g H2 steam reforming.

3.3.2 Feed chemistry effects on feed rankings for CI

Feedstock CI rankings differ between No-IHC and Selective-IHC processing (Table 5). This is a feed quality impact driven primarily by the different volumes of non-jet fractions sent to IHC among feeds. It boosts the CI of soybean oil from 4.9 kg/b below to 0.4 kg/b above the CI of menhaden oil with the addition of Selective-IHC (*Id.*). With 88.3% of its volume outside the jet fuel range compared with 57.7% of menhaden oil (Table 1, > C16 fractions), soy oil sends 30.6% more feed to Selective-IHC than menhaden oil. More IHC feed requires more hydrogen, boosting steam reforming emissions more with soy than with menhaden oil. Similarly, canola oil sends 27.9% more feed to Selective-IHC than herring oil (*Id.*). This boosts canola oil CI from 0.9 kg/b below to 3.9 kg/b above herring oil CI with the addition of Selective-IHC (Table 5).

3.3.3 How livestock fat feeds could affect soy oil and canola oil refining CI

When switching from soy or canola oil to livestock fat enables a refiner to boost jet fuel yield by repurposing its refinery for Selective-IHC processing, that intentional hydrocracking can boost jet yield from soy and canola oil feeds as well. Thus, instead of shutting down when, for any reason at any time, livestock fat becomes too scarce or expensive, the refiner could make jet fuel by going back to soybean oil or canola oil feedstock. This could increase refining CI by 16.2 kg/b (29%) for soy oil, and 17.2 kg/b (32%) for canola oil, based on our results for the Selective-IHC *versus* No-IHC processing strategies in Table 5.

3.4 Feedstock effects on CI resulting from Isom-IHC hydrogen demand

Livestock fat and palm oil could maximize jet fuel yield by enabling Isom-IHC processing, since these feeds minimize HDO hydrogen demand (chapters 1 and 2). Their relatively lower non-jet fractions do not contribute to this effect on Isom-IHC because, in contrast to Selective-IHC, Isom-IHC processes the entire feed stream output from HDO. Direct effects of feed quality variability on Isom-IHC cracking are relatively weak, since HDO both saturates and removes oxygen from Isom-IHC inputs. Thus, the relative feed rankings for CI from No-IHC processing carry over to the Isom-IHC feed rankings with only minor differences (Table 5). However, by cracking of the entire HDO output, Isom-IHC further boosts hydrogen demand, thus hydrogen steam reforming emissions, resulting in the highest HEFA refining CI for all feeds (*Id.*).

Across feeds and process options, from the lowest to the highest impact combinations of feeds and processing, HEFA refining CI increases by 34.8 kg CO_2/b (75%), and CI increases in 122 (79.7%) of 153 feed switching combinations that could boost jet fuel yield (tables 1, 3, 5).

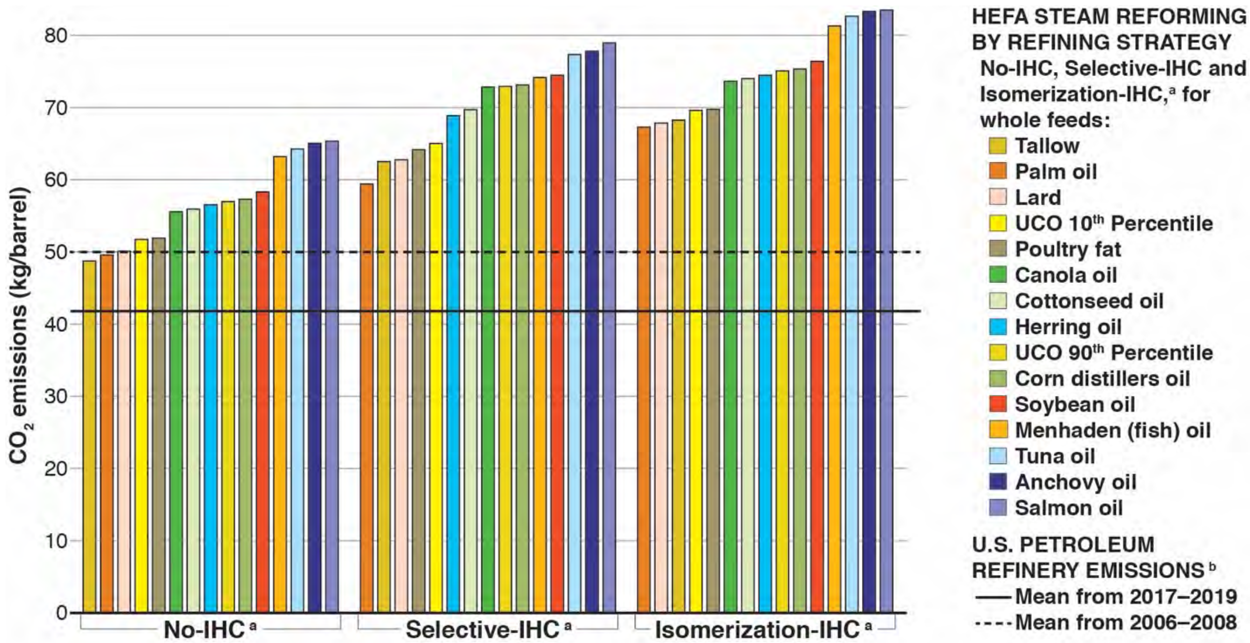
3.5 Comparison with petroleum refining CI by feedstock and processing strategy

Chart 1 plots results for feedstock-related impacts on the variability of HEFA refining CI from HEFA steam reforming emissions against the CI of U.S. petroleum refining. Our results in Table 5 are shown by processing strategy and, within each strategy, each feed is represented by a color-coded column. The height of the column represents the contribution of steam reforming to HEFA refining CI for that particular feed and processing strategy. The solid black line shown at approximately 41.8 kg/b (kg CO_2/barrel crude processed) represents the average U.S. petroleum refining CI from 2015 through 2017.[6] We use this (41.8 kg/b) as our benchmark. For added context, average U.S. petroleum refining CI from 2006–2008,[7] a period when the U.S. refinery crude slate was denser and higher in sulfur than during 2015–2017[8] resulting in higher historic U.S. crude refining industry CI,[7] is represented by the dashed line at 50 kg/b in the chart.

Please note what HEFA emissions Chart 1 does and does not show. It shows HEFA refining steam reforming emissions only. This helps us focus on our question about refining CI impacts from HEFA feedstock switching to target jet fuel, which are directly related to HEFA steam reforming rates. It *does not* show total direct emissions from HEFA refining.

3.5.1 HEFA refining CI impacts are significant compared with crude refining

Other HEFA refining emissions besides those from steam reforming—from fuel combustion to heat and pressurize HEFA hydro-conversion reactors, precondition and pump their feeds, and distill and blend their products—could add roughly 21 kg/b of additional HEFA refining CI.[2] Thus, for a rough comparison of petroleum refining CI with total HEFA refining CI, imagine adding 21 kg/b to the top of each column in Chart 1. HEFA refining CI approaches or exceeds *double* the CI of petroleum refining. Clearly, expanding HEFA jet fuel would increase the CI of hydrocarbon fuels processing substantially.



1. HEFA Steam Reforming Emissions *v.* Total U.S. Petroleum Refining Emissions, kg CO_2/barrel feed input.

a. HEFA steam reforming emissions only: values shown exclude CO_2 emitted by other HEFA refining process and support equipment. This contrasts with the petroleum refining emissions shown, which include all direct emissions from crude refining. Including all direct emissions from HEFA refining could increase the HEFA estimates shown by approximately 21 kg/barrel.[2] The "No-IHC" strategy excludes intentional hydrocracking (IHC); the "Selective-IHC" strategy adds emission from producing hydrogen consumed by intentional hydrocracking of feed fractions comprised of hydrocarbons outside the jet fuel range; the "Isomerization-IHC" strategy adds emissions from intentional hydrocracking of whole feeds in the isomerization step of HEFA fuels production. HEFA data shown include feed-driven emissions in Table 5 plus additional steam reforming emissions (2.5 kg/b) from producing the additional hydrogen that is lost to unintended side-reaction cracking, solubilization, scrubbing and purging (*see* Table 8).[1]

b. U.S. petroleum refinery emissions including total direct CO_2 emitted from steam reforming and all other petroleum refinery process and support equipment at U.S. refineries. Mean from 2015 through 2017 based on total refinery emissions and distillation inputs reported by the U.S. Energy Information Administration (EIA).[6] Mean from 2006 through 2008 represents a period of historically high-carbon U.S. refining industry crude inputs.[7 8]

3.5.2 High-jet feed impacts on processing targeting jet fuel can increase refining CI

Feeds that enable intentional hydrocracking to boost jet fuel yield could increase HEFA refining CI significantly (Chart 1). Here we report feed switching CI increments compared with No-IHC processing of soy and canola oils to target diesel yield (*see* Table 5) as percentages of our petroleum crude refining benchmark: Switching to Selective IHC with anchovy and salmon oils increases CI by 47% to 56% (of crude refining CI) while switching to Selective IHC with menhaden oil increases CI by 38% to 44%. Switching to Isom-IHC with tallow increases CI by 24% to 30% while switching to Isom-IHC with palm oil increases HEFA refining CI by 21% to 28% of crude refining CI. Switching to Selective-IHC with tallow increases CI by 10% to 17%. Only Selective-IHC with palm oil has similar CI to that of No-IHC with soy oil (+3%).

3.5.3 High-jet feed CI impacts are mixed in processing targeting HEFA diesel yield

Compared with No-IHC processing of soy or canola oils, which are the combinations of processing and feeds that maximize HEFA diesel yield, No-IHC with fish oils could increase refining CI while No-IHC with palm oil or livestock fats could decrease CI. For example, switching to anchovy oil could increase No-IHC HEFA refining CI over that of canola and soy oils by 16% to 23% of crude refining CI while switching to tallow could decrease it by 16% to 23% of crude refining CI. But there is a caveat to those estimates.

In theory, feeding tallow to No-IHC processing could boost jet fuel yield to one-third of feedstock volume (Table 1) while lowering CI by 6.8 or 9.5 kg/b below canola or soy oil in No-IHC processing, the strategies refiners use to maximize HEFA diesel yield. However, this would require three barrels of tallow feed per barrel of jet fuel yield, emphasizing a crucial assumption about HEFA biofuel as a sustainable jet fuel solution—it assumes a sustainable feedstock supply. That assumption could prove dangerously wrong, as shown in Chapter 4.

4. HEFA jet fuel feedstock and carbon sinks: Could the feedstocks that maximize HEFA jet fuel instead of diesel yield have comparatively high indirect climate impacts?

Increasing demand for limited supplies of feedstocks that refiners could use to boost HEFA jet fuel yield and make more HEFA jet fuel risks increasing deforestation and other serious indirect climate impacts. HEFA biofuel feedstocks are purpose-derived lipids also needed for food and other uses,[9 10] are globally traded, and can increase in price with increased biofuel demand for their limited supply.[2] Ecological degradation caused by expanded production and harvesting of the extra lipids for biofuels has, in documented cases, led to emissions from natural carbon sinks due to biofuels. Those emissions have traditionally been labeled as an "indirect land use impact," but as shown above, refiners seeking to maximize HEFA jet fuel production also could use fish oil feedstocks. The term "indirect carbon impacts," meant to encompass risks to both terrestrial and aquatic carbon sinks, is used in this chapter.

4.1 Natural carbon sinks that HEFA jet fuel feedstock acquisition could affect

Feedstocks that increase HEFA jet fuel production could have indirect impacts on land-based carbon sinks, aquatic carbon sinks, or both. At the same time the impact mechanisms differ between terrestrial and aquatic ecosystems. Part 4.1.1 below discusses carbon sink risks due to land degradation, and part 4.1.2 discusses carbon sink risks due to fishery depletion.

4.1.1 Land degradation risks: Carbon sinks in healthy soils and forests

Even before new Sustainable Aviation Fuel plans raised the potential for further expansion of HEFA feedstock acquisition, biofuel demand for land-based lipids production was shown to cause indirect carbon impacts. A mechanism for these impacts was shown to be global land use change linked to prices of commodities tapped for both food and fuel.[11] Instead of cutting carbon emissions, increased use of some biofuel feedstocks could boost crop prices, driving crop and pasture expansion into grasslands and forests, and thereby degrading natural carbon sinks to result in biofuel emissions which could exceed those of petroleum fuels.[11]

Indirect carbon impacts of lipid feedstocks which further HEFA biofuel expansion could tap have been observed and documented in specific cases. International price dynamics involving palm oil, soybean oil, biofuels and food were linked as factors in the deforestation of Southeast Asia for palm oil plantations.[12] Soy oil prices were linked to deforestation of the Amazon and Pantanal in Brazil for soybean plantations.[13 14 15] Demand-driven changes in European and U.S. prices were shown to act across the oil crop and animal fat feedstocks for HEFA biofuels.[16] Rapeseed (canola) and soy biofuels demand drove palm oil expansion in the Global South as palm oil imports increased for other uses of those oils displaced by biofuels in the Global North.[17] Indirect land use impacts of some soy oil—and most notably, palm oil—biofuels were found to result in those biofuels emitting more carbon than petroleum fuels they are meant to replace.[17 18 19] Current U.S. policy discourages palm oil-derived biofuel for this reason.[20]

As of 2021, aerial measurements suggest that combined effects of deforestation and climate disruption have turned the southeast of the great Amazonian carbon sink into a carbon source.[21] Market data suggest that plans for further HEFA biofuels expansion have spurred an increase in soybean and tallow futures prices.[22 23 24] A joint report by two United Nations-sponsored bodies, the Intergovernmental Panel on Climate Change and the Intergovernmental Science-Policy Platform on Biodiversity and Ecosystem Services, warns that expansion of industrial biofuel feedstock plantations risks inter-linked biodiversity and climate impacts.[25]

Moreover, these risks are mutually reinforcing. Potential pollinator declines,[26] climate heating-driven crop losses,[27] biofuel policy-driven food insecurity,[28] and the prospect that, once a biofuel also needed for food is locked into place, retroactive limits on land use conversion could worsen food insecurity,[11] reveal another aspect of this carbon sink risk. Namely, the assumption asserted by HEFA biofuel proponents, that we can "grow our way out" of limits on biomass diversion to biofuels by increasing crop yields and reverse course later if that does not work, risks lasting harm.

4.1.2 Fishery depletion risks: The biological carbon pump in world oceans

Increasing demand for fish products could further drive fisheries depletion, thereby risking substantial emissions from the oceanic carbon sink. This potential impact, like that on terrestrial carbon sinks, has received intensifying scientific attention in recent years, but appears to remain less widely known to the general public. Fished species have crucial roles in the mechanisms that send carbon into the oceanic carbon sink, as shown below.

Oceans account for 71% of the Earth surface[29] and remove roughly one-fourth to one-third of total carbon emissions from all human activities annually.[30 31] A portion of the CO_2 exchange between air and water at the sea surface is sequestered in the deep seas via inter-linked shallow, mid-reach, and benthic ecosystems that comprise a "biological pump" in which fished species play key roles. *See* Illustration 1.

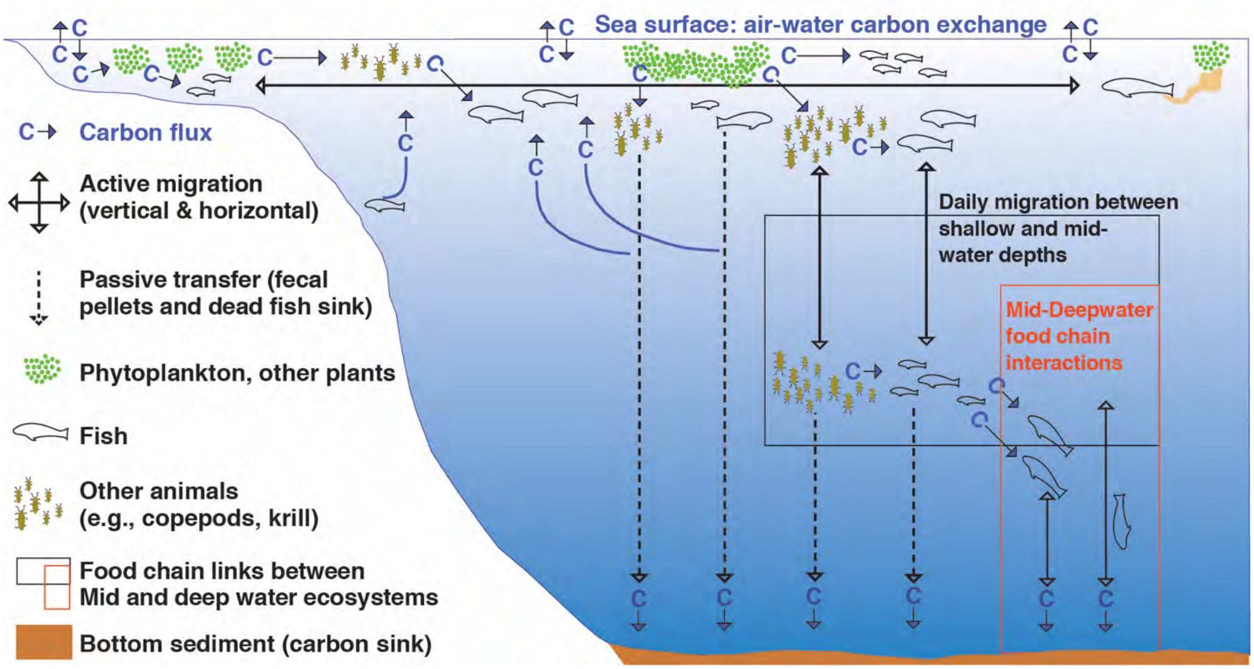


Illustration 1. Biological pump to the deep oceans carbon sink

Fish have key roles in the inter-linked shallow, mid-reach, and benthic ecosystems that drive a "biological pump" which sends carbon into the deep seas. In well-lit shallow waters, photosynthesis converts CO_2 into organic carbon that is taken up by plants, then by animals in aquatic food webs, and horizontal migration of faster-swimming species fertilizes phytoplankton blooms in the nutrient-poor open oceans, reinforcing the carbon uptake. Some of this carbon falls to the deep sea in fecal pellets and carcasses of fish and other animals (dashed lines shown), while respiration releases CO_2 from aquatic animals and from bacterial degradation of fecal matter (upward-curving lines), some of which re-enters the atmosphere at the sea surface. Active vertical migration (solid vertical lines) further drives the biological pump. A substantial portion of both fish and their invertebrate prey biomass feeds near the surface at night and in much deeper mid-reaches of the ocean during daylight—where deep-sea fish species migrate and feed as well (black and red boxes). Here in the mid-reaches, a greater portion of the carbon in fecal pellets and dead fish sinks to the bottom, and active migration feeding by deep sea fish transfers additional carbon to the deep sea. The organic carbon that reaches the deep sea can be sequestered in sediments for hundreds to thousands of years.

In well-lit shallow waters, photosynthesis converts CO_2 into organic carbon that is taken up by plants and then by animals in ocean food webs. (Illustration, top.) Horizontal migration of faster-swimming species fertilizes phytoplankton blooms in the nutrient-poor open oceans, reinforcing the carbon uptake (*Id.*).[25 31] Some of this carbon sinks to the deep sea in fecal pellets and carcasses of fish and other animals (dashed lines shown)[25 32] but not all of it; some of the CO_2 released in respiration by aquatic animals and bacterial degradation of fecal matter re-enters the atmosphere at the sea surface (upward-curving lines).[30 32] That sea surface carbon exchange emphasizes the role of active vertical migration (solid vertical lines) in the biological pump.

For both fish and their invertebrate prey, a substantial portion of their ocean biomass feeds near the surface at night and in much deeper mid-reaches of the ocean during daylight[25]—where deep-sea fish species migrate and feed as well.[32] Here in the mid-reaches, a greater portion of the carbon in fecal pellets and dead fish sinks to the bottom, and active migration feeding by deep sea fish transfers additional carbon to the deep sea.[25 30 32] The organic carbon that reaches the deep sea can be sequestered in sediments for hundreds to thousands of years.[25 30 32]

Although impacts are not yet fully quantified,[25] at present—even at "maximum sustainable yield"—fishery depletion impacts the oceanic carbon sink by removing roughly half of the fisheries biomass that would otherwise be in world oceans.[25 31] This exports the carbon in fish from ocean sequestration to land, where that exported carbon then enters the atmosphere.[25 31] Fished species are targeted selectively, disrupting ecosystems involved in the biological pump and potentially reducing both the passive and the active transport of carbon to deep sea carbon sequestration.[25 32] Worse, as demands for limited fisheries catches have grown, bottom trawling, which directly disrupts and releases carbon from ocean sediments, may already have reduced the oceanic carbon sink by as much as 15–20%.[25] In this context fish oil demand, while only a small fraction of total fisheries catch, is still supplied more from whole fish than from fish byproducts, and is projected to grow by a few percentage points through 2030.[10] Thus, potential additional fish oil demand for biofuel poses an indirect carbon impact risk.

4.2 Historic impact assessments for high jet fuel yield HEFA feedstocks

HEFA refiners could maximize jet fuel instead of diesel production using palm oil, fish oil, or livestock fats for feedstocks, as shown in Chapter 2 above. Historic demand for these specific feedstocks has resulted in relatively high indirect carbon impacts from one of them, and raises questions about future impacts from increased demand for the other two high jet fuel yield feeds.

4.2.1 Palm oil: High jet fuel yield, high impact and current use restriction

With 46.5% of its fatty acid feedstock volume comprised of carbon chains in the jet fuel range, palm oil ranks first among major HEFA feedstocks for the potential to increase HEFA jet fuel production. *See* Table 1. Palm oil also has perhaps the highest known potential among HEFA feedstocks for indirect land use impacts on natural carbon sinks (§ 4.1.1). Some palm oil-derived biofuels have reported fuel chain carbon intensities that exceed those of the petroleum fuels they are meant to replace (*Id.*). However, current U.S. policy restricts the use of palm oil-derived biofuels to generate carbon credits due in large part to this high indirect carbon impact.[20] Future biofuel demand could affect the efficacy of this use restriction.

4.2.2 Fish oil: High jet fuel yield and low carbon impact assumed for residual supply

Fish oils rank second, fourth, sixth, seventh and ninth for jet fuel-range fractions at 42.3%, 32.7%, 32.6% and 27.5% of their feed volumes. *See* Table 1. Moreover, their relatively low diesel fractions (48.9–59.8%) and relatively high feed fractions with carbon chains longer than the ideal diesel range, which could be broken into twin jet fuel hydrocarbons (*Id.*), might favor jet fuel production by intentional hydrocracking strategies. Current biofuel use of fish oil is low, and is assumed to be residual biomass, and thus to have relatively low indirect carbon impact. However, that assumption is based on historic fish oil usage patterns at historic biofuel demand. If HEFA refiners seek to maximize jet fuel production by tapping fish oil in larger amounts, this has a potential to result in high indirect carbon sink risk by further depleting fisheries that contribute to the biological pump which sequesters carbon in the deep sea (§ 4.1.2).

4.2.3 Livestock fat: High jet fuel yield and low carbon impact assumed for residual supply

Tallow, poultry fat, and lard rank third, fifth, and eighth for jet fuel-range fractions at 33.3%, 32.7%, and 30% of their feed volumes, respectively. *See* Table 1. For these livestock fats, HEFA feedstock acquisition impact and supply estimates are linked by the assumption that only "waste" residues of livestock fat biomass will be used for biofuels.[33 34] This results in lower estimates for feedstock acquisition impacts by assuming that impacts from using farm and pastureland to feed the livestock are assigned to other uses of the livestock, such as food. At the same time, this assumption limits the supply for biofuels to only "waste" which, it is assumed, will not result in using more land for livestock feed in response to increased HEFA feedstock demand. These current assumptions—that increased demand will not cause land use impacts because it will not increase livestock production—limit current estimates of both supply and indirect carbon impact. Again, however, the current assumptions driving indirect carbon impact estimates are based on historic lipids usage patterns, which may change with increasing HEFA feedstock demand.

4.3 Feedstock acquisition risks to carbon sinks could be substantial at usage volumes approaching the current HEFA jet fuel blend limit

Impacts of these differences among feedstocks—and HEFA feedstock acquisition impacts overall—depend in large part upon future HEFA demand for limited current feedstock supplies. Moreover, indirect carbon impacts can include impacts associated with displacing other needs for these lipid sources, notably to feed humans directly and to feed livestock or aquaculture fish. This section compares potential HEFA SAF feedstock demand with limited current lipid supplies to assess potential indirect carbon impacts of specific and combined HEFA feedstocks.

4.3.1 Potential future HEFA jet fuel feedstock demand in the U.S.

SAF implementation could drive dramatic HEFA feedstock demand growth. In 2019, the most recent year before COVID-19 disrupted air travel, U.S. SAF consumption was estimated at 57,000 barrels,[35] only 0.009% of the 636 million barrels/year (MM b/y) U.S. jet fuel demand.[36] Since SAF must be blended with petroleum jet fuel and can be a maximum of half the total jet fuel,[35] implementation of SAF goals could result in future jet biofuel production of as much as 318 MM b/y assuming no growth in jet fuel demand. This would represent SAF growth to approximately 5,580 *times* the 2019 SAF biomass demand. HEFA technology is on track to claim the major share of this prospective new biomass demand.

Since 2011, "renewable" diesel production used in California alone, a surrogate for U.S. HEFA biofuel use,[35] grew by a factor of 65 times to 2.79 MM b/y as of 2013, by 142 times to 6.09 MM b/y as of 2016, and 244 times to 10.5 MM b/y as of the end of 2019.[37] Planned new HEFA capacity targeting the California fuels market and planned for production by 2025 totals approximately 124 MM b/y,[38] another potential increase of more than tenfold from 2019–2025.

Financial incentives for oil companies to protect their otherwise stranded refining assets are a major driver of HEFA growth—for example, in the two biggest biorefineries to be proposed or built worldwide to date.[2] More crude refining asset losses can thus spur more HEFA growth.[2]

Further idling of crude refining assets is indeed likely. Climate constraints drive the need to replace gasoline, with most credible expert assessments showing approximately 90% of gasoline to be replaced in mid-century climate stabilization scenarios.[39] [40] [41] [42] More efficient electric vehicles with lower total ownership costs will force gasoline replacement as vehicle stock rolls over, and this independent driver could replace approximately 80% of U.S. gasoline vehicles by mid-century.[2] Designed and built to co-produce gasoline and maximize gasoline production, U.S. crude refineries cannot produce distillates alone and will be idled as gasoline is replaced.[2]

Refiners can—and would be highly incentivized to—protect those otherwise stranded assets by repurposing their crude refining equipment for HEFA biofuel production. Assuming the low end of the mid-century crude refining asset loss projections noted above, 80% of existing U.S. refinery hydrogen production capacity could be repurposed to supply approximately 2.66 million metric tons per year (MM t/y) of hydrogen for HEFA production at idled and repurposed crude refineries. *See* Table 6 below.

Depending on the mix of HEFA jet fuel processing strategies that the prospective new HEFA refining fleet might employ, this much repurposed hydro-conversion capacity could make enough HEFA jet fuel to replace 36% to 39% of total U.S. jet fuel demand, assuming no growth from 2019 demand. *Id.* Notably, if the existing[37] and planned[38] capacity through 2025 is built and tooled for the same jet fuel yields, this mid-century projection implies a threefold HEFA capacity growth rate from 2026–2050, slower than the tenfold growth planned from 2019–2025.

In order to "book-end" an uncertainty previewed in chapters 1 and 2 above, Table 6 shows two potential HEFA jet fuel growth scenarios. Scenario S-1 assumes a future U.S. HEFA refining fleet with 30% of refineries using the No-IHC strategy and 70% using the Isom-IHC strategy. This scenario assumes many refiners that repurpose for HEFA production lack existing equipment to repurpose for intentional hydrocracking separately and in addition to the hydro-deoxygenation and isomerization reactors needed for all HEFA processing, and refiners choose not to build new hydrocracking capacity into their asset repurposing projects. Scenario S-2 assumes the opposite: many refiners have that existing capacity or choose to build new capacity into their repurposing projects, resulting in a mix with 20% of refineries using the No-IHC strategy, 70% using the Selective-IHC strategy, and 10% using the Isom-IHC strategy.

Relying mainly on Selective-IHC, which cuts hydrogen demand compared with Isom-IHC, Scenario S-2 makes more jet fuel from the same amount of repurposed hydrogen capacity, but nevertheless, at 71–72 MM t/y, feedstock demand is very high in both scenarios (Table 6).

Table 6. Potential HEFA jet fuel growth scenarios to mid-century in the U.S.

t: metric ton **MM t/y:** million metric tons/year

Total U.S. crude refining hydrogen plants capacity in 2021 (MM t/y) [a]					3.32
Assumption by 2050: 80% repurposed for HEFA biofuel (MM t/y)					2.66
Scenario S-1: No use of selective and intentional hydrocracking (Selective-IHC) [a]					
Process strategy		No-IHC	Selective-IHC	Isom-IHC	Total
Refineries breakdown	(% feed)	30 %	0 %	70 %	100 %
Hydrogen input [b]	(kg/t feed)	9.04	0.00	28.5	37.5
Feed input [b]	(MM t/y)	21.3	0.00	49.7	71.0
Jet fuel yield [c]	(MM t/y)	4.75	0.00	24.5	29.3
HEFA jet fuel production in the U.S. as a percentage of total 2019 U.S. jet fuel demand:					36 %
Scenario S-2: High use of selective and intentional hydrocracking (Selective-IHC) [a]					
Process strategy		No-IHC	Selective-IHC	Isom-IHC	Total
Refineries breakdown	(% feed)	20 %	70 %	10 %	100 %
Hydrogen input [b]	(kg/t feed)	6.02	26.6	4.06	36.7
Feed input [b]	(MM t/y)	14.5	50.7	7.25	72.4
Jet fuel yield [c]	(MM t/y)	3.23	25.0	3.58	31.8
HEFA jet fuel production in the U.S. as a percentage of total 2019 U.S. jet fuel demand:					39 %

Absent policy intervention, given renewable incentives and assuming severe feed supply limitations are overcome, U.S. HEFA jet fuel production could replace 36–39% of current U.S. petroleum jet fuel, and demand 71–72 million tons/year of lipids feedstock annually, by mid-century. Crude refiners could be highly incentivized to repurpose assets, which would be stranded by climate constraints and electric vehicles, for HEFA biofuels; less clear is the mix of processing strategies the repurposed HEFA refining fleet would use. Refiners could boost jet fuel yield by intentional hydrocracking of HEFA isomerization feeds (Isom-IHC), or do so while limiting hydrogen costs by intentional hydrocracking of selected feed fractions separately from the isomerization step needed for all fractions (Selective-IHC). However, some refineries lack existing equipment for one or both IHC options and may not choose to build onto repurposed equipment. Scenarios in this table span a conservatively wide range of fleet-wide processing strategies in order to "book-end" this uncertainty, resulting in the feed and fuel ranges shown above. The 80% petroleum capacity idling assumed by 2050[2] is generally consistent with highly credible techno-economic analyses, which, however, generally assume a different biofuel technology and feedstock source.[40–42] **a.** U.S. refinery hydrogen capacity from *Oil & Gas Journal*.[5] **b.** Hydrogen and feed inputs based on feed-weighted data from Table 3 and a feed blend SG of 0.914. **c.** Jet fuel yields based on yield-wtd. data from Table 1 at 0.775/0.914 jet/feed SG (No-IHC) and Pearlson et al. (IHC).[3] U.S. jet fuel demand in 2019 from USEIA (636.34 MM bbl),[36] or 81.34 MM t/y at the petroleum jet fuel density in the survey reported by Edwards (0.804 SG).[43] Diesel is the major HEFA jet fuel coproduct. Figures shown may not add due to rounding.

4.3.2 Limited HEFA jet fuel feedstock supplies in the U.S. and world

Current feedstock supplies limit the sustainability of HEFA jet fuel as a substantial component of U.S. jet fuel at rates well below the 50% SAF blend limit. Total current U.S. lipids production for all uses could supply only 29% of the feedstock needed for HEFA jet fuel to replace 36% to 39% of 2019 U.S. jet fuel use, as shown for scenarios S-1 and S-2 in Table 7 below. Other uses of these lipids crucially involve direct and indirect human needs for food, and in these scenarios, U.S. HEFA biofuel alone displaces one-third of all other existing lipids usage globally (Table 7).

Further, at even half the HEFA jet fuel production rates shown in Table 7, current global production of no one lipid source can supply the increased biofuel feedstock demand without displacing significant food system resources. This observation reveals the potential for impacts that cut across multiple prospective HEFA feedstock sources.

Table 7. HEFA feedstock demand in potential U.S. petroleum jet fuel replacement scenarios compared with total current U.S. and world production for all uses of lipids.

MM t/y: million metric tons/year

U.S. Feedstock Demand Scenarios [a]	No 100% Replacement NA: blend limit		36% Scenario S-1 71.0 MM t/y		39% Scenario S-2 72.4 MM t/y	
Current Feed-stock Supply	U.S. (MM t/y)	World (MM t/y)	Supply / Demand (%) U.S.	World	Supply / Demand (%) U.S.	World
Palm oil [b]	0.00	70.74	0%	99%	0%	98%
Fish oil [c]	0.13	1.00	0.18%	1.4%	0.18%	1.4%
Livestock fat [d]	4.95	14.16	7%	20%	7%	20%
Soybean oil [e]	10.69	55.62	15%	78%	15%	77%
Other oil crops [e]	5.00	73.07	7%	103%	7%	101%
Total Supply	20.77	214.59	29%	309%	29%	302%

Total current U.S. production for all uses of lipids also tapped for biofuel could supply only 29% of potential U.S. HEFA jet fuel feedstock demand in 2050. **a.** HEFA feedstock demand data from Table 6. **b.** Palm oil data from Oct 2016–Sep 2020.[44] **c.** Fish oil data from 2009–2019 (U.S.)[45] and unspecified recent years (world).[46] **d.** Livestock fat data from various dates (US)[9] and 2018 (world).[47] **e.** Soybean oil, palm oil, and other oil crops data from unspecified dates for used cooking oil (US),[9] Oct 2016–Sep 2020 for oil crops also used for biofuel (US),[48] and Oct 2016–Sep 2020 for oilseed crops (world).[44]

4.3.3 Feed-specific and total feed-blend indirect carbon impact potentials

As shown in Table 7 and discussed above, the scale of potential HEFA feedstock demand affects the answer to our question about whether feedstocks refiners could use to increase HEFA jet fuel yield could result in relatively more serious indirect carbon impacts.

Palm oil: High volume displacement and international fueling impacts potential

With the highest global availability of any current HEFA feed (Table 7), palm oil is likely to fill in for current uses of other HEFA feeds that growing U.S. feedstock demand for HEFA jet fuel would displace from those uses. This could occur regardless of restrictions on palm oil biofuel, increasing the indirect carbon impacts associated with palm oil expansion. Deforestation in Southeast Asia caused by palm oil expansion has been linked to biofuel demand for soy and rapeseed (canola) oils in the U.S. and Europe at past, much lower, biofuel feedstock demand, as described in section 4.1.1. Its high global availability also increases the likelihood that, despite U.S. policy, palm oil derived HEFA jet fuel could burn in many commercial flights. Jets may fuel this palm biofuel in various nations—including fueling for the return legs of international flights originating in the U.S. Palm oil can thus be considered a high jet fuel yield and relatively high indirect carbon impact HEFA feedstock.

Fish oil: Unique risk at low HEFA feed blend volume

In contrast to palm oil, fish oil is an extremely low availability HEFA feedstock and is unique among HEFA feeds in raising risks to the oceanic carbon sink. Equally important, fish oil has hard-to-replace aquaculture and pharmaceutical uses.[10] At 1.4% of current world supply for HEFA jet fuel demand scenarios in Table 7, fish oil is unlikely to be targeted as a major

HEFA feedstock industry wide. But this also means that existing uses of fish oil that are hard to replace could be fully displaced, driving further fisheries depletion, even if fish oil comprises as little as 1.4% of potential future HEFA feeds. Increased fishing pressure for fish oil is difficult to discount in demand scenarios approaching those shown (*Id.*), as significant upward pressure on lipids prices could impact lipids markets globally. Indeed, world fish oil demand for all uses is projected to grow and continue to be produced in substantial part from whole fish catch.[10] That fish biomass would essentially be extracted from the oceanic carbon sink to emit carbon from land-based uses, however, the larger and more uncertain impact could be on the effectiveness of ocean carbon sequestration via the biological pump (§ 4.1.2).

Available information thus identifies the potential for a future fish oil biofuel impact which may or may not materialize but nevertheless poses significant risk. Fish oil can be considered a high jet fuel yield and relatively high indirect carbon risk HEFA feedstock.

Livestock fat: likely displacement and possible supply growth impacts

While total current livestock fat production could supply only 20% of potential HEFA feedstock demand (Table 7), its relatively high jet fuel yield and relatively low (assumed) indirect carbon impacts could make livestock fat an important fraction of the expanding HEFA feeds mix. This would displace its existing uses, where the fats would likely be replaced by expanded demand for other lipids with relatively higher indirect carbon impacts. High-availability replacements such as palm and soy oils (*Id.*) would likely fill those displaced uses, and both palm and soy oils have relatively high indirect carbon impacts (§ 4.1.1).

Additionally—and notwithstanding the likelihood that livestock protein production would remain the priority—it is possible that the unprecedented growth in livestock fat demand might alter the balance among choices for producing human protein intake in favor of this high jet fuel yield "byproduct" feedstock. This balance is dynamic, as suggested by trends either toward or away from vegetarian diets in various human populations globally, such that this possibility is difficult to discount given the potential for unprecedented livestock fat demand growth. And if HEFA demand were to drive livestock production growth, livestock production is, in fact, a high carbon emission enterprise.[31 49] In view of these likely and possible impacts, livestock fat can be considered a high jet fuel yield and relatively high indirect carbon risk HEFA feedstock.

Feed blends: limited residue supply worsens indirect carbon impacts

Impacts and risks of high jet fuel yield feedstock add to those of feed blends that could be used for HEFA jet fuel, and limited global "residue" feedstock supply heightens these impacts.

HEFA feedstock demand to replace just 18% of 2019 U.S. jet fuel use—half that shown in Table 7—would far exceed current total U.S. production for *all uses* of lipids also tapped for biofuels. One implication of this is the need to consider food and fuel uses of the global lipids supply by other nations. Importantly, at 4.28% of world population, the U.S. per capita share of world production for low impact "residue" feeds from livestock fat and fish oil (Table 7) is less than 0.65 MM t/y, less than 1% of potential U.S. HEFA jet fuel feedstock demand (*Id.*). The limited supply of low impact "residue" feedstocks, in turn, limits alternatives to palm oil or livestock production growth that can feed potential HEFA jet fuel growth. Current major feed alternatives for HEFA jet fuel are limited to soybean oil and other oil crops (*Id.*).

For example, what if U.S. palm biofuel is prohibited, livestock and fish oil production do not grow, and U.S. HEFA "residue" feedstock acquisition grows to eight times its per capita share (5.2 MM t/y)? At half of its minimum potential mid-century growth, HEFA feedstock demand for SAF in the U.S. would be approximately 35.5 MM t/y (Table 7). This 5.2 MM t/y of low-impact feed would meet only 15% of that demand and leave 30.3 MM t/y of that demand unmet. Supplying the 30.3 MM t/y of unmet demand for just half of potential U.S. HEFA jet fuel growth could induce growth of 23.5% in current combined global production for soy and other oil crops, excluding palm oil (*Id.*).

Moreover, the excess U.S. use of limited global residue supply in the example above could have an impact. It could displace the lower-impact HEFA jet fuel feed for SAF fueled in other nations, which could replace residue feeds with higher indirect carbon impact feeds. This would only shift emissions to HEFA jet fueling elsewhere, without providing a global climate benefit.

Thus, even if U.S. policy effectively discourages palm oil biofuel and livestock production does not grow, the potential HEFA jet fuel expansion could be expected to spur an expansion of soybean, corn, and other plant oil crops. Significant indirect carbon impacts have been linked to biofuels demand for soybean and other plant oil feedstocks at past biofuel demand levels that were substantially lower than current and potential future HEFA demand (§ 4.1.1). While this complicates the answer to our question about indirect carbon impacts of feeds to boost HEFA jet fuel yield, importantly, it further informs our answer. It shows that these heightened impacts and risks would add to significant potential impacts of increased total HEFA feedstock demand.

In plausible future SAF implementation scenarios, among the relatively high jet fuel yield feedstocks, palm oil could have relatively serious indirect carbon impacts, and both fish oil and livestock fat could pose relatively serious but currently uncertain indirect carbon impact risks. Those impacts and risks would add to significant potential carbon sink impacts from the blends of feedstocks that could supply HEFA refineries, in which lower impact "residue" feedstocks could supply only a small fraction of total HEFA feedstock growth. Natural limits on total supply for the type of feedstock that HEFA technology can process appear to make replacing any significant portion of current petroleum jet fuel use with this type of biofuel unsustainable.

5. Limitations and suggestions for future work

Two types of data limitations which may affect potential outcomes for SAF were identified in the course of this research. The first involves HEFA technology: interchangeability among other uses of its feedstocks; and its potential future evolution. These HEFA-specific limitations are discussed in Section 5.1 below. The second involves other alternatives to petroleum jet fuel combustion which, though they are outside the scope of this report, warrant mention due to limitations of HEFA technology identified by this research. These are discussed briefly as suggested priorities for future work in Section 5.2.

5.1 HEFA biofuel impact assessment data limitations

5.1.1 Limited cross-feed displacement quantification data

HEFA feedstocks are not "wastes." All of them are lipids, and more specifically, triacylglycerols of fatty acids, which can be converted to functionally similar biological or chemical uses by many biological processes (e.g., digesting food) and chemical processes (e.g., HEFA processing with hydrocracking). Further, these lipids have interchangeable and largely competing uses now, including food for human populations, livestock feeds, pet food, aquaculture feeds, and feedstocks for making soap, wax, lubricants, plastics, natural pigments, cosmetic products and pharmaceutical products.[9 10] Accordingly, increased biofuel demand for one source of these lipids displaces another existing use of that feedstock, thereby increasing demand and prices for other sources of lipids as well. Indeed, this has occurred, leading to indirect land use impacts that increased carbon emissions associated with biofuels (§ 4.1.1).

For example, if diverting tallow from soap making to HEFA jet fuel forces soap makers to use more palm oil, that jet fuel indirectly emits carbon associated with that extra production of palm oil. The livestock fat biofuel would cause an indirect carbon impact that current biofuel impact accounting practices for "waste" residue feedstocks assume it does not cause.

However, the hypothetical extreme wherein all lipids are 100% fungible, and any increase in HEFA demand for any of these feedstocks would have the same indirect impact by increasing collective demand for all other feeds by the same amount, also seems unrealistic. Some types of lipids, such as those that increase jet fuel production and those people eat directly, could attract relatively higher demand and command relatively higher prices. At present, *how much* demand increase for each lipid source increases indirect carbon impacts associated with cross-feed demand increase has not yet been quantified by universally accepted estimates.

Herein, we take the view that the uses of lipids also tapped for HEFA biofuels are fungible to a significant extent which varies among specific lipids sources and uses. In this view, indirect carbon impacts of future demand for palm oil exceed those of other HEFA feeds which would not be favored by refiners seeking to boost jet fuel production, but by amounts that are not yet fully quantifiable. That quantitative uncertainty results from the data limitations discussed above and explains why this report does not attempt to quantify the feed-specific indirect carbon impacts documented in Chapter 4.

5.1.2 Renewable fuel hydrogen specification error

Splitting water with electricity supplied by solar or wind power—renewable powered electrolysis—produces zero-emission hydrogen fuel. Unfortunately, renewable fuel standards incentivize HEFA fuels even though much of the hydrogen in those hydrocarbons is produced from non-renewable fossil fuels. This is a mistake. This mistake has led to an important limitation in the data for assessing the future potential of HEFA jet fuel.

Hydrogen steam reforming repurposed from crude refining drives the high CI of HEFA refining and its variability among HEFA feedstocks and processing strategies (Chapter 3). Renewable-powered electrolysis could eliminate those steam reforming emissions and result in HEFA refining CI lower than that of petroleum refining.[2] However, the combination of public incentives to refiners for HEFA biofuel, and their private incentives to avoid costs of stranded steam reforming assets they could repurpose and electrolysis they need not build to reap those public incentives, has resulted in universal reliance on steam reforming in HEFA processing. Would the public incentives outweigh the private incentives and cut refining CI if this mistake were corrected, or would the companies decide that another alternative to HEFA jet fuel is more profitable? Since current fuel standards allow them to maximize profits by avoiding the question, there are no observational data to support either potential outcome.

Additionally, if refiners were to replace their steam reformers with renewable-powered electrolysis, energy transition priorities could make that zero-emission hydrogen more valuable for other uses than for biofuel,[2] and biomass feed costs also would weigh on their decisions.[19] Thus, for purposes of the potential impacts assessment herein, and in the absence of observational data on this question, we take the view that assuming HEFA refining without steam reforming emissions would be speculative, and would risk significant underestimation of potential HEFA jet fuel impacts.

5.1.3 Proprietary catalyst development data

Catalysts are crucial in HEFA refining, and although many catalyst data are claimed as trade secrets, their refining benefits are typically advertised, especially if new catalysts improve yields. The search for a new catalyst that can withstand the severe conditions in HEFA reactors and improve processing and yields has been intensive since at least 2013.[50 51 52 53 54 55 56]

From this we can infer two things. First, given the maturity of the hydro-conversion technology crude refiners repurpose for HEFA refining, and that long and intensive search, a newly invented catalyst formulation which improves reported HEFA jet fuel yield significantly appears unlikely. Second, given the incentive, the invention of such a new catalyst is possible. Again, however, many specific catalyst data are not reported publicly. Our findings herein are based on publicly reported, independently verifiable data. This limitation in publicly reported catalysis data thus has the potential to affect our yields analysis.

5.2 Priorities for future work

5.2.1 Cellulose biomass alternatives—what is holding them back?

Cellulosic residue biomass such as cornstalks, currently composted yard cuttings, or sawdust can be used as feedstock by alternative technologies which qualify as SAF.[19 35] Using this type of feedstock for SAF could lessen or avoid the indirect carbon impacts from excessive HEFA jet fuel demand for limited lipids biomass that are described in Chapter 4. Indeed, economy-wide analyses of the technologies and measures to be deployed over time for climate stabilization suggest prioritizing cellulosic biomass, to the extent that biofuels will be needed in some hard-to-decarbonize sectors.[42 57 58] Despite its promise, however, the deployment of cellulosic distillate biofuel has stalled compared with HEFA biofuel. Less clear are the key barriers to its growth, the measures needed to overcome those barriers, and whether or not those measures and the growth of cellulosic jet fuel resulting from them could ensure that SAF goals will be met sustainably. This points to a priority for future work.

5.2.2 Alternatives to burning jet fuel—need and potential to limit climate risks

Even complete replacement of petroleum jet fuel with SAF biofuel combustion would result in ongoing aviation emissions, and would thus rely on additional and separate carbon capture-sequestration to give us a reasonable chance of stabilizing our climate. At the current jet fuel combustion rate the scale of that reliance on "negative emission" technologies, which remain unproven at that scale, is a risky bet. Meanwhile, besides alternative aircraft propulsion systems, which are still in the development stage, there are alternatives to jet fuel combustion which are technically feasible now and can be used individually or in combination.

Technically feasible alternatives to burning jet fuel include electrified high-speed rail, fuel cell powered freight and shipping to replace air cargo, and conservation measures such as virtual business meetings and conserving personal air-miles-traveled for personal visits. While we should note that such travel pattern changes raise social issues, so does climate disruption, and most people who will share our future climate are not frequent fliers. Importantly as well, public acceptance of new travel alternatives is linked to experiencing them. Thus, biofuel limitations, climate risks, and human factors suggest needs to prioritize the development and deployment of alternatives to petroleum jet fuel that do not burn carbon.

5.2.3 Limited safety data record for flying with new fuels

Jet biofuels appear to differ from petroleum jet fuels in their cold flow properties at high altitude, combustion properties, and potential to damage fuel system elastomer material.[19] Those that can be used as SAF have been approved subject to blending limits, which permit SAF to be "dropped-in" to conventional jet fuel up to a maximum of 50% of the blend.[59] All seven types of biofuels approved for SAF are subject to this condition.[59] SAF/petroleum jet fuel blends that do not meet this condition are deemed to present potential safety issues.[59]

However, remarkably limited historical use of SAF (§4.3.1) has resulted in a limited data record for assessing its safety in actual operation. That is important because new hazards which result in dangerous conditions over long periods of operation have repeatedly been discovered only by rigorous post-operational inspection or post-incident investigation, the histories of both industrial and aviation safety oversight show. There is an ongoing need to ensure flight safety risks of biofuels are closely monitored, rigorously investigated, transparently communicated, and proactively addressed by "inherent safety measures"[60] designed to eliminate any specific hazards identified by that future work.

Table 8. Data and methods table for feed-specific estimates.[a]

Fatty acid (FA) in HEFA oil feed				Oxygen	Carbon	FA-specific hydrogen inputs	
			Density	content	double	Deoxygenation[c]	Saturation[d, e]
common name	Shorthand	Formula[b]	(kg/b)*	(wt. %)*	bonds	(kg H_2/b)	(kg H_2/b)
Caprylic Acid	C8:0	$C_8H_{16}O_2$	145	22.2	0	8.09	0.00
Capric Acid	C10:0	$C_{10}H_{20}O_2$	142	18.6	0	6.65	0.00
Lauric Acid	C12:0	$C_{12}H_{24}O_2$	140	16.0	0	5.63	0.00
Myristic Acid	C14:0	$C_{14}H_{28}O_2$	137	14.0	0	4.84	0.00
Myristoleic Acid	C14:1	$C_{14}H_{26}O_2$	143	14.1	1	5.10	1.27
Pentadecanoic Acid	C15:0	$C_{15}H_{30}O_2$	134	13.2	0	4.45	0.00
Palmitic Acid	C16:0	$C_{16}H_{32}O_2$	135	12.5	0	4.26	0.00
Palmitoleic Acid	C16:1	$C_{16}H_{30}O_2$	142	12.6	1	4.50	1.13
Margaric Acid	C17:0	$C_{17}H_{34}O_2$	136	11.8	0	4.04	0.00
Stearic Acid	C18:0	$C_{18}H_{36}O_2$	134	11.2	0	3.79	0.00
Oleic Acid	C18:1	$C_{18}H_{34}O_2$	141	11.3	1	4.04	1.01
Linoleic Acid	C18:2	$C_{18}H_{32}O_2$	143	11.4	2	4.12	2.06
Linolenic Acid	C18:3	$C_{18}H_{30}O_2$	145	11.5	3	4.21	3.16
Stearidonic Acid	C18:4	$C_{18}H_{28}O_2$	148	11.6	4	4.33	4.33
Arachidic Acid	C20:0	$C_{20}H_{40}O_2$	131	10.2	0	3.38	0.00
Gondoic Acid	C20:1	$C_{20}H_{38}O_2$	140	10.3	1	3.65	0.91
Eicosadienoic Acid	C20:2	$C_{20}H_{36}O_2$	144	10.4	2	3.76	1.88
Homo-γ-linoleic Acid	C20:3	$C_{20}H_{34}O_2$	146	10.4	3	3.84	2.88
Arachidonic Acid	C20:4	$C_{20}H_{32}O_2$	147	10.5	4	3.88	3.88
Eicosapentaenoic Acid	C20:5	$C_{20}H_{30}O_2$	150	10.6	5	4.00	5.00
Henicosanoic Acid	C21:0	$C_{21}H_{42}O_2$	142	9.80	0	3.50	0.00
Heneicosapentaenoic Acid	C21:5	$C_{21}H_{32}O_2$	149	10.1	5	3.79	4.74
Behenic Acid	C22:0	$C_{22}H_{44}O_2$	131	9.39	0	3.09	0.00
Erucic Acid	C22:1	$C_{22}H_{42}O_2$	137	9.45	1	3.26	0.81
Docosadienoic Acid	C22:2	$C_{22}H_{40}O_2$	143	9.51	2	3.43	1.71
Docosatetraenoic Acid	C22:4	$C_{22}H_{36}O_2$	151	9.62	4	3.66	3.66
Docosapentaenoic Acid	C22:5	$C_{22}H_{34}O_2$	148	9.68	5	3.62	4.52
Docosahexaenoic Acid	C22:6	$C_{22}H_{32}O_2$	150	9.74	6	3.68	5.52
Lignoceric Acid	C24:0	$C_{24}H_{48}O_2$	140	8.68	0	3.06	0.00
Tetracosenoic Acid	C24:1	$C_{24}H_{46}O_2$	141	8.73	1	3.11	0.78

* **b (barrel):** 42 U.S. gallons; **wt. %:** weight percent on fatty acid

a. See notes to this table for feedstock-specific data sources.

b. Formula symbols; carbon: C (12.011 g/mol); hydrogen: H (1.00794 g/mol); oxygen: O (15.995 g/mol).

c. Deoxygenation: Hydrogen consumed to remove and replace oxygen and propane knuckle-fatty acid bonds.

b. Saturation: Hydrogen consumed to saturate carbon double bonds in HEFA processing.

e. Additional process hydrogen consumption in side-reaction cracking, solubilization, scrubbing **and** purge losses not shown.

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Table 8. Data and methods table for feed-specific estimates continued.[a]

Whole feed fatty acids		Selected plant oils, livestock fats and fish oils						
Fatty acid	FA	Median of sample analysis profile data reported based on C18:2, in wt. % [a]						
Common name	Shorthand	Soybean	Corn	Canola	Cottonseed	Palm	Tallow	Lard
Caprylic	C8:0					0.186		
Capric	C10:0					0.324		0.070
Lauric	C12:0					2.284	1.010	
Myristic	C14:0	0.100		0.040	0.860	1.108	3.384	1.280
Myristoleic	C14:1							
Pentadecanoic	C15:0							
Palmitic	C16:0	11.000	12.860	4.248	23.600	41.480	24.495	25.000
Palmitoleic	C16:1	0.100	0.100	0.287	0.360	0.167	4.040	3.000
Margaric	C17:0			0.069		0.059	2.020	0.330
Stearic	C18:0	4.000	1.760	1.752	2.400	4.186	17.525	12.540
Oleic	C18:1	23.400	26.950	60.752	17.740	39.706	42.121	44.000
Linoleic	C18:2	53.200	55.880	20.713	54.420	9.902	3.293	11.000
Linolenic	C18:3	7.800	1.260	8.980	0.600	0.196	1.818	0.550
Stearidonic	C18:4							
Arachidic	C20:0	0.300	0.390	0.713	0.220	0.304	0.313	0.190
Gondoic	C20:1		0.280	1.277	0.070	0.078	0.081	0.800
Eicosadienoic	C20:2							0.740
Homo-γ-linoleic	C20:3							0.110
Arachidonic	C20:4							0.300
Eicosapentaenoic	C20:5							
Henicosanoic	C21:0							
Heneicosapentaenoic	C21:5							
Behenic	C22:0	0.100	0.120	0.307	0.110	0.039		
Erucic	C22:1			0.594				
Docosadienoic	C22:2							
Docosatetraenoic	C22:4		0.120					
Docosapentaenoic	C22:5		0.180					
Docosahexaenoic	C22:6							
Lignoceric	C24:0			0.099		0.049		
Tetracosenoic	C24:1							
Whole feed FAs	O_2 wt. %	11.50	11.50	11.35	11.71	11.99	11.80	11.66
	Deoxygenation (kg H_2 /b)	4.11	4.11	4.06	4.14	4.19	4.11	4.13
	Saturation (kg H_2 /b)	1.58	1.48	1.35	1.32	0.61	0.60	0.76
C8–C16 Fraction	(vol. %)	11.71	13.56	4.78	25.67	46.47	33.34	30.00
	Deoxygenation (kg H_2 /b)	4.27	4.26	4.28	4.28	4.38	4.39	4.32
	Saturation (kg H_2 /b)	0.01	0.01	0.07	0.02	0.004	0.14	0.12
C15–C18 Fraction	(vol. %)	99.46	98.88	96.85	98.70	95.63	95.18	96.53
	Deoxygenation (kg H_2 /b)	4.11	4.11	4.08	4.13	4.13	4.08	4.09
	Saturation (kg H_2 /b)	1.59	1.48	1.37	1.34	0.64	0.63	0.75
> C18 Fraction	(vol. %)	0.43	1.12	3.11	0.42	0.49	0.41	2.10
	Deoxygenation (kg H_2 /b)	3.31	3.49	3.43	3.35	3.37	3.43	3.70
	Saturation (kg H_2 /b)	0.00	1.38	0.55	0.16	0.15	0.19	1.68

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Table 8. Data and methods table for feed-specific estimates continued.[a]

Whole feed fatty acids		Selected plant oils, livestock fats and fish oils, *continued*					
Fatty acid	FA	Median of sample analysis profile data reported based on C18:2, wt. % [a]					
Common name	Shorthand	Poultry	Anchovy	Herring	Menhaden	Salmon	Tuna
Caprylic	C8:0						
Capric	C10:0						
Lauric	C12:0						
Myristic	C14:0	0.618	6.636	7.755	8.602	6.044	5.903
Myristoleic	C14:1	0.206					0.447
Pentadecanoic	C15:0		0.701	0.408	0.538	0.769	0.359
Palmitic	C16:0	24.206	16.355	15.306	21.505	17.143	17.670
Palmitoleic	C16:1	6.951	7.757	8.469	10.108	2.198	5.961
Margaric	C17:0	0.108	0.935	0.510	1.075	1.099	0.650
Stearic	C18:0	5.814	3.738	2.143	3.333	2.637	4.155
Oleic	C18:1	42.157	12.150	17.245	15.000	15.385	16.078
Linoleic	C18:2	18.137	1.636	1.633	2.151	1.648	1.068
Linolenic	C18:3	0.657	5.607	0.612	1.398	4.451	1.748
Stearidonic	C18:4		2.336	2.551	3.333	3.077	
Arachidic	C20:0		0.841		0.323	0.385	0.408
Gondoic	C20:1	0.392	3.738	11.224	1.075	1.978	4.922
Eicosadienoic	C20:2						0.272
Homo-*γ*-linoleic	C20:3						3.437
Arachidonic	C20:4		2.103	0.408	1.720	2.967	0.184
Eicosapentaenoic	C20:5		14.486	8.776	13.441	12.637	9.282
Henicosanoic	C21:0						
Heneicosapentaenoic	C21:5		1.869		0.806	2.582	
Behenic	C22:0	0.118					0.078
Erucic	C22:1	0.098	3.224	15.102	0.645	6.099	0.311
Docosadienoic	C22:2						
Docosatetraenoic	C22:4						
Docosapentaenoic	C22:5		1.869	1.327	2.258	3.077	5.252
Docosahexaenoic	C22:6		14.252	6.327	12.366	15.385	20.670
Lignoceric	C24:0	0.098					0.845
Tetracosenoic	C24:1	0.363					0.583
Whole feed FAs	O_2 wt. %	11.70	11.33	11.22	11.53	11.11	11.20
	Deoxygenation (kg H_2 /b)	4.13	4.06	3.99	4.13	4.01	4.01
	Saturation (kg H_2 /b)	0.91	2.34	1.52	2.08	2.42	2.31
C8–C16 Fraction	(vol. %)	32.69	32.56	32.73	42.26	27.48	31.46
	Deoxygenation (kg H_2 /b)	4.33	4.45	4.47	4.45	4.42	4.44
	Saturation (kg H_2 /b)	0.25	0.28	0.30	0.28	0.09	0.24
C15–C18 Fraction	(vol. %)	98.09	52.19	49.34	59.81	49.73	48.92
	Deoxygenation (kg H_2 /b)	4.13	4.20	4.20	4.21	4.17	4.17
	Saturation (kg H_2 /b)	0.92	1.02	0.89	0.85	1.01	0.64
> C18 Fraction	(vol. %)	1.07	40.93	42.68	31.25	43.96	44.52
	Deoxygenation (kg H_2 /b)	3.31	3.76	3.59	3.81	3.72	3.72
	Saturation (kg H_2 /b)	0.67	4.31	2.52	4.83	4.27	4.34

Continued next page

Table 8. Data and methods table for feed-specific estimates continued.[a]

Whole feed fatty acids		Used cooking oil (UCO) variability			
Fatty acid	FA	Percentiles on C18:2, in wt. % *			
Common name	Shorthand	10th Percentile	25th Percentile	75th Percentile	90th Percentile
Caprylic	C8:0				
Capric	C10:0				
Lauric	C12:0				
Myristic	C14:0	0.909	2.479	1.735	
Myristoleic	C14:1				
Pentadecanoic	C15:0				
Palmitic	C16:0	20.606	20.248	16.412	12.420
Palmitoleic	C16:1	4.646		1.735	
Margaric	C17:0				
Stearic	C18:0	4.848	12.810	5.235	5.760
Oleic	C18:1	53.434	38.017	29.843	26.930
Linoleic	C18:2	13.636	23.967	41.324	49.600
Linolenic	C18:3	0.808	2.066	3.500	4.930
Stearidonic	C18:4				
Arachidic	C20:0	0.121			0.750
Gondoic	C20:1	0.848			
Eicosadienoic	C20:2				
Homo-γ-linoleic	C20:3				
Arachidonic	C20:4				
Eicosapentaenoic	C20:5				
Henicosanoic	C21:0				
Heneicosapentaenoic	C21:5				
Behenic	C22:0	0.030			
Erucic	C22:1	0.071			
Docosadienoic	C22:2				
Docosatetraenoic	C22:4				
Docosapentaenoic	C22:5				
Docosahexaenoic	C22:6				
Lignoceric	C24:0	0.040			
Tetracosenoic	C24:1				
Whole feed FAs	O_2 wt. %	11.64	11.59	11.59	11.55
	Deoxygenation (kg H_2 /b)	4.11	4.09	4.12	4.10
	Saturation (kg H_2 /b)	0.91	0.95	1.29	1.44
C8–C16 Fraction	(vol. %)	26.81	23.49	20.61	12.90
	Deoxygenation (kg H_2 /b)	4.32	4.32	4.33	4.26
	Saturation (kg H_2 /b)	0.20	0.00	0.10	0.09
C15–C18 Fraction	(vol. %)	97.95	97.46	98.21	99.19
	Deoxygenation (kg H_2 /b)	4.11	4.08	4.11	4.10
	Saturation (kg H_2 /b)	0.92	0.97	1.31	1.46
> C18 Fraction	(vol. %)	1.12	0.00	0.00	0.81
	Deoxygenation (kg H_2 /b)	3.56	0.00	0.00	3.38
	Saturation (kg H_2 /b)	0.75	0.00	0.00	0.00

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Table 8. Data and methods table for feed-specific estimates continued.[a]

Data for feedstock fractions outside the jet fuel range (> C16)

Feedstock		Soybean	Corn	Canola	Cottonseed	Palm	Tallow	Lard
> C16 Fraction	(vol. %)	88.29	86.44	95.22	74.33	53.53	66.66	70.00
Deoxygenation (kg H_2 /b)		4.09	4.08	4.05	4.09	4.03	3.98	4.00
Saturation (kg H_2 /b)		1.78	1.70	1.41	1.75	1.12	0.82	1.03

Feedstock		Poultry	Anchovy	Herring	Menhaden	Salmon	Tuna
> C16 Fraction	(vol. %)	67.31	67.44	67.27	57.74	72.52	68.54
Deoxygenation (kg H_2 /b)		4.03	3.88	3.76	3.92	3.86	3.82
Saturation (kg H_2 /b)		1.22	3.29	2.10	3.33	3.25	3.21

Feedstock		Used Cooking Oil (UCO			
Percentile on C18:2 in wt.%		10th	25th	75th	90th
> C16 Fraction	(vol. %)	73.19	76.51	79.39	87.10
Deoxygenation (kg H_2 /b)		4.03	4.03	4.07	4.07
Saturation (kg H_2 /b)		1.16	1.23	1.58	1.65

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Table 8. Data and methods table for feed-specific estimates continued.[a]

Process hydrogen consumption by feedstock and processing strategy (kg/b feed)

HDO Δ ONLY	Jet range (C8–C16)			Diesel range (C15–C18)			Longer chains (> C18)		
(No-IHC)	(vol.%)	Ox (kg/b)	Sat (kg/b)	(vol.%)	Ox (kg/b)	Sat (kg/b)	(vol.%)	Ox (kg/b)	Sat (kg/b)
High jet/high diesel									
Palm oil	46.47	4.38	0.004	95.63	4.13	0.64	0.49	3.37	0.15
Tallow fat	33.34	4.39	0.14	95.18	4.08	0.63	0.41	3.43	0.19
Poultry fat	32.69	4.33	0.25	98.09	4.13	0.92	1.07	3.31	0.67
Lard fat	30.00	4.32	0.12	96.53	4.09	0.75	2.10	3.70	1.68
UCO 10th P.	26.81	4.32	0.20	97.95	4.11	0.92	1.12	3.56	0.75
Cottonseed oil	25.67	4.28	0.02	98.70	4.13	1.34	0.42	3.35	0.16
High jet/low diesel									
Menhaden oil	42.26	4.45	0.28	59.81	4.21	0.85	31.25	3.81	4.83
Herring oil	32.73	4.47	0.30	49.34	4.20	0.89	42.68	3.59	2.52
Anchovy oil	32.56	4.45	0.28	52.19	4.20	1.02	40.93	3.76	4.31
Tuna oil	31.46	4.44	0.24	48.92	4.17	0.64	44.52	3.72	4.34
Salmon oil	27.48	4.42	0.09	49.73	4.17	1.01	43.96	3.72	4.27
Low jet/high diesel									
Corn (DCO) oil	13.56	4.26	0.01	98.88	4.11	1.48	1.12	3.49	1.38
UCO 90th P.	12.90	4.26	0.09	99.19	4.10	1.46	0.81	3.38	0.00
Soybean oil	11.71	4.27	0.01	99.46	4.11	1.59	0.43	3.31	0.00
Canola oil	4.78	4.28	0.07	96.85	4.08	1.37	3.11	3.43	0.55

HDO & INTENTIONAL	HDO Δ (Ox + Sat)			Intentional Hydrocracking (IHC)			Jet target H2 Δ by processing case		
HYDROCRACKING	Jet rg.	Diesel rg.	> C18	Selective-IHC		Isom IHC	No-IHC	Select-IHC	Isom-IHC
vol. weighted data	(kg/b)	(kg/b)	(kg/b)	(b fraction)	(kg/b)	(kg/b)	(kg/b)	(kg/b)	(kg/b)
High jet/high diesel	—fractions do not add—			> C16	(factor)*	(factor)*	whole feed	whole feed	whole feed
Palm oil	2.04	4.57	0.02	0.535	1.87	1.80	4.79	5.79	6.60
Tallow fat	1.51	4.47	0.01	0.667	2.10	1.99	4.71	6.11	6.70
Poultry fat	1.50	4.95	0.04	0.673	1.85	1.82	5.03	6.28	6.85
Lard fat	1.33	4.67	0.11	0.700	1.84	1.81	4.85	6.13	6.65
UCO 10th P.	1.21	4.92	0.05	0.732	1.85	1.82	5.01	6.37	6.83
Cottonseed oil	1.10	5.40	0.01	0.743	1.88	1.84	5.44	6.84	7.28
High jet/low diesel									
Menhaden oil	2.00	3.03	2.70	0.577	1.93	1.84	6.18	7.30	8.02
Herring oil	1.56	2.51	2.61	0.673	1.87	1.83	5.50	6.76	7.33
Anchovy oil	1.54	2.72	3.30	0.674	1.93	1.86	6.37	7.67	8.23
Tuna oil	1.47	2.35	3.59	0.685	1.94	1.87	6.29	7.62	8.16
Salmon oil	1.24	2.57	3.51	0.725	1.91	1.85	6.40	7.78	8.25
Low jet/high diesel									
Corn (DCO) oil	0.58	5.53	0.05	0.864	1.86	1.84	5.58	7.19	7.42
UCO 90th P.	0.56	5.51	0.03	0.871	1.87	1.84	5.55	7.17	7.39
Soybean oil	0.50	5.67	0.01	0.883	1.86	1.84	5.68	7.33	7.52
Canola oil	0.21	5.28	0.12	0.952	1.85	1.84	5.40	7.16	7.24

Note: H_2 inputs shown exclude side-reaction cracking, solubilization, scrubbing and purge gas losses.

* IHC H_2 consumption at 1.3 wt. % feed (Pearlson et al.), in kg/b IHC input.

See table notes next page

Explanatory notes and data sources for Table 8.

Feeds shown have been processed in the U.S. except for palm oil, which is included because it is affected indirectly by U.S. feedstock demand and could be processed in the future, possibly in the U.S. and more likely for fueling international flights in various nations. Median values shown for feed composition were based on the median of the data cluster centered by the median value for C18:2 (linoleic acid) for each individual whole feed. Blend data were not available for used cooking oil (UCO), except in the form of variability among UCO samples collected, which showed UCO to be uniquely variable in terms of HEFA processing characteristics. The table reports UCO data as percentiles of the UCO sample distribution.

Data for feedstock composition were taken from the following sources:

Soybean oil[54 55 61 62 63 64 65 66]

Corn oil (distillers corn oil)[54 61 63 65 67 68 69 70]

Canola oil (includes rapeseed oil)[54 55 61–65 67 69 71 72 73]

Cottonseed oil[54 55 63 65 67]

Palm oil[54 55 62–65 67 68 74]

Tallow (predominantly beef fat)[54 64 69 71 75 76 77 78 79]

Lard (pork fat)[68 76 79]

Poultry fat[54 69 76 79 80]

Anchovy[81]

Herring[82 83]

Menhaden[54 81 82]

Salmon[81 83]

Tuna[81 84 85]

Used cooking oil (UCO)[74 78 86 87 88 89 90 91 92]

Hydrogen consumption to deoxygenate and saturate feeds was calculated from fatty acids composition data for each feed and feed fraction shown. Note that O_2 wt.% data shown are for fatty acids excluding the triacylglycerol propane knuckle; O_2 molar data rather than wt.% data were used to calculate hydrogen demand. Added hydrogen consumption by intentional hydrocracking was calculated at 1.3 wt.% on feed from Pearlson et al.[3] and the inputs to each intentional hydrocracking strategy type (Chapter 1), which were taken from the data in Table 8 and used as shown at the end of Table 8 above. Selective-IHC input volume differs among feeds, as described in chapters 1–3.

Hydrogen losses to side-reaction cracking, solubilization in process fluids, and scrubbing and purging of process gases (not shown in Table 8) result in additional hydrogen production, and thus steam reforming emissions. This was addressed for the steam reforming emissions illustrated in Chart 1 by adding 2.5 kg CO_2/b feed to the emissions shown in Table 5, based on steam reforming emissions of 9.82 g CO_2/g H_2 (Chapter 3) and assumed additional hydrogen production of 0.26 kg H_2/b feed. This is a conservative assumption for hydrogen which reflects a lower bound estimate for those losses. Hydrogen losses through side-reaction cracking, solubilization, scrubbing and purging combined would likely range from 102 SCFB (0.26 kg/b) to more than 196 SCFB (0.5 kg/b),[2] based on analysis of data from a range of published HEFA processing and petroleum processing hydro-conversion process analyses and professional judgment.[2 4 50–56 93 94 95 96]

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APPENDIX C

Karras, G., *Technical Report in Support of Comments* (Karras, 2021c)

Technical Report by Greg Karras

G. Karras Consulting (Community Energy reSource)[1]
16 December 2021

Regarding the
Martinez Refinery Renewable Fuels Project
Draft Environmental Impact Report, County
File: # CDLP20-02046
State Clearinghouse No. 2021020289

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.

[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

[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.

[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 <u>Key differences in processing compared with petroleum refining</u>

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

[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)

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[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 <u>Change and variability in feedstock chemistry and processing characteristics</u>

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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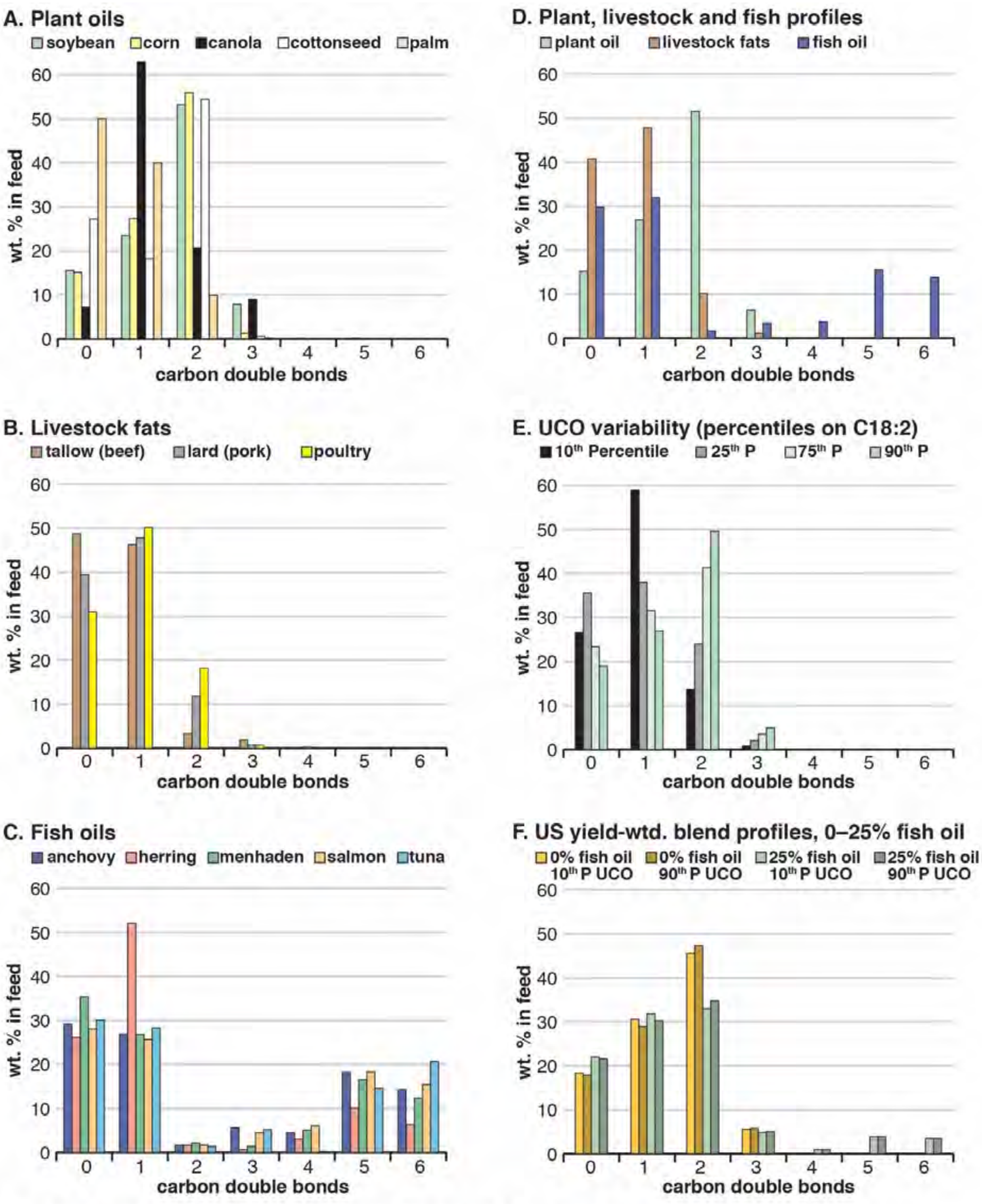
[37] <u>*See*</u> Karras, 2010. Combustion Emissions from Refining Lower Quality Oil: What is the global warming potential? *Environ. Sci. Technol.* 44(24): 9584–9589. DOI: 10.1021/es1019965. Appended hereto as Attachment 6.
[38] <u>*See*</u> CSB, 2013. *Interim Investigation Report, Chevron Richmond Refinery Fire;* U.S. Chemical Safety Board: Washington, D.C. https://www.csb.gov/file.aspx?Documentid=5913. Appended hereto as Attachment 7.
[39] <u>*See*</u> 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] <u>*See*</u> 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] <u>*See*</u> 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.

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[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,

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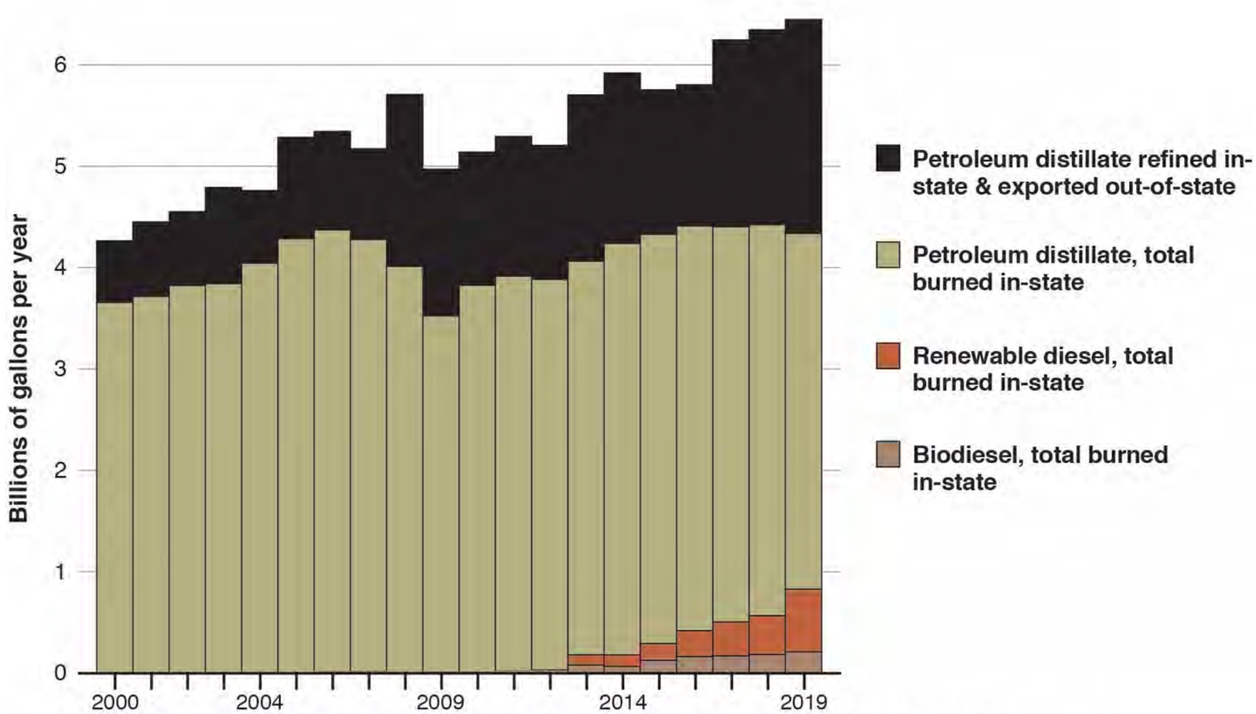
[63] "Greenhouse gas (GHG)," in this section, means carbon dioxide equivalents (CO_2e) at the 100-year horizon.
[64] "Project would result in an overall decrease in emissions ... [including] indirect GHG emissions" (DEIR p. 3.8-20) and "GHG emissions from stationary and mobile sources" (DEIR p. 3.8-22).
[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).

[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	Pre-COVID range (2012–2019)			Comparison of 2021 data with
	in 2021	Minimum	Median	Maximum	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) Minimum	Median	Maximum	Comparison of 2021 data with the same month in 2010–2019
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. *See* 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 <u>Incomplete and inaccurate evaluation of process material explosion and fire hazard</u>

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]

[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

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[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.

[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

[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 The DEIR did not identify significant hydrogen-related process hazard impacts that could result from the project

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

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.

[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

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[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 <u>Petroleum storage and transfer rather than refining is the existing project site condition</u>

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 <u>Petroleum crude refining at the site has been shuttered with no plans to restart</u>

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

[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. See § 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 Closing the crude refinery relieved a pre-existing condition of serious and growing petroleum refining structural overcapacity in California and on the West Coast

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

[161] 2019 Annual Report. See "From the Chairman and CEO" at p. 1.
[162] *Id.*
[163] See § 2.2 herein; see 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.

3. 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.

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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20. 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.

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29. Sigma-Aldrich, 2021. *Safety Data Sheet: Hydrogen Sulfide;* Merck KGaA: Darmstadt, DE.

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ATTACHMENT B

TECHNICAL SUPPLEMENT

Greg Karras

Senior Scientist, Community Energy reSource

FEIR figures 3-1 to 3-4 are <u>not</u> evidence for crude refining restart

Instead of responding to evidence that this crude refinery closed in a corporate consolidation of refining assets driven in large part by a growing gap between refining capacity and domestic demand,[1] the FEIR argues that California petroleum consumption trends *alone* provide evidence crude refining would restart here absent the project.[2] That is not true, because the refining fleet—including the part of it owned by Marathon—has been overbuilt. This overcapacity is measurable and demonstrable by comparing crude refining rates to crude refining capacity, as our DEIR comments showed.[3] Having ignored this fact in response to comment, the FEIR now presents "new" data which it says supports crude refining restart, but which do not.

A standard refining measurement, operable utilization rate (capacity utilization)[4] reveals refinery overcapacity. More precisely, it measures the otherwise operable crude capacity that lays idle after serving profitable demand. Measured as percentage of capacity in barrels per calendar day (b/cd), it accounts for downstream bottlenecks in the refinery, for scheduled and unscheduled down time, and for environmental constraints associated with refinery operations. Thus, for example, a capacity utilization of 90 percent means that ten percent of otherwise operable refining capacity is idled.

Charts 1A and 1B illustrate capacity utilization trends across refineries in California and the West Coast (PADD 5). Data shown are five and ten-year running averages. The long-term comparisons reveal structural overcapacity more reliably than short-term averages, which can mask the real trend in "noise" created by external factors such as unrelated economic cycles.

The ten-year mean comparisons reveal clear trends. West Coast capacity utilization fell from approximately 90 percent during the ten years ending in 2006 to below 86% during the ten years ending in 2013, and was below 86 percent for nearly all of the period from 2014 to the present (Chart 1A). California refining fleet capacity utilization was lower still. Fully 15 to 17 percent of operable capacity statewide sat idle on average during the 16 years ending over the period including 2014 through 2020 (*Id.*). Five-year mean utilization fell even more dramatically in the period from 2006–2017, partially rebounded more quickly as well, but never approached the historic peak refinery utilization for the five years ending in 2006 (Chart 1B).

Data shown in charts 1A and 1B were taken from the California Energy Commission Fuel Watch[5] and the US Energy Information Administration refinery capacity[6] and capacity

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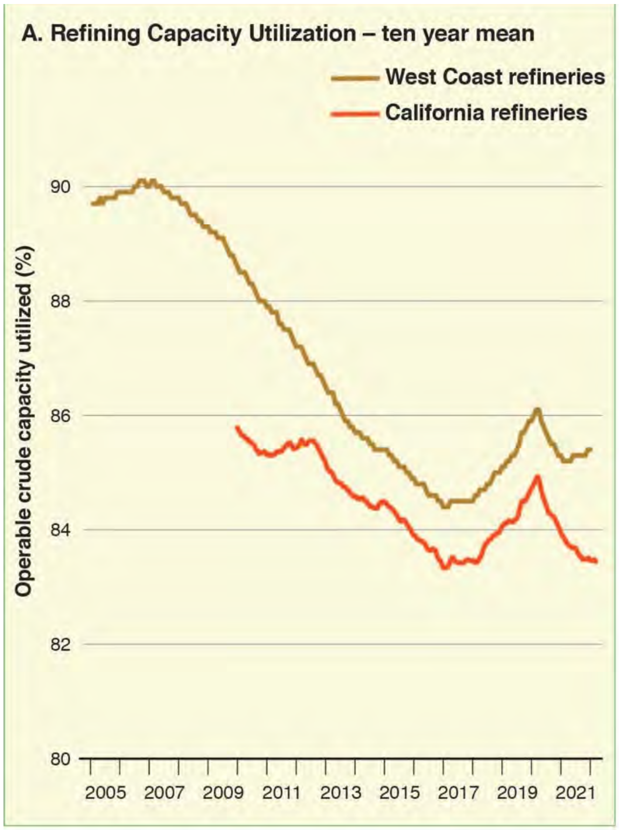
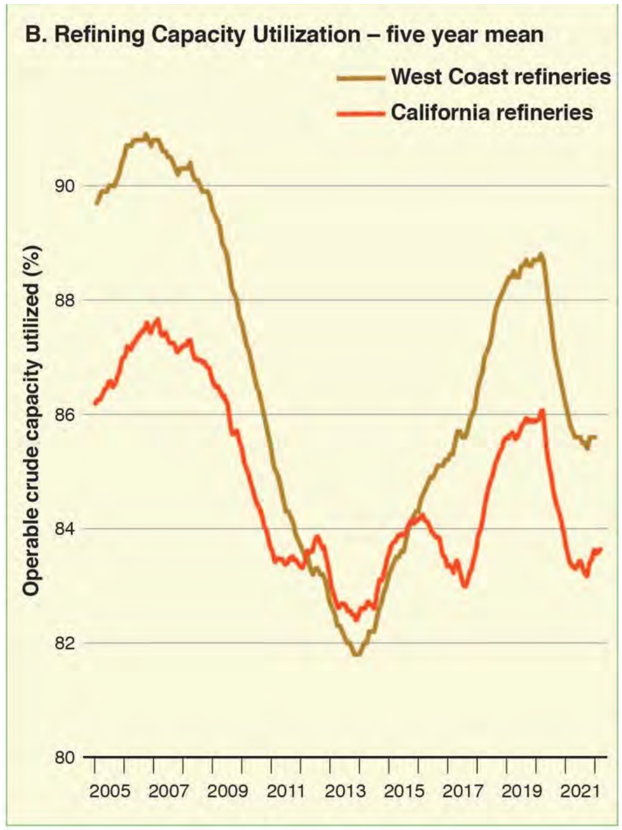
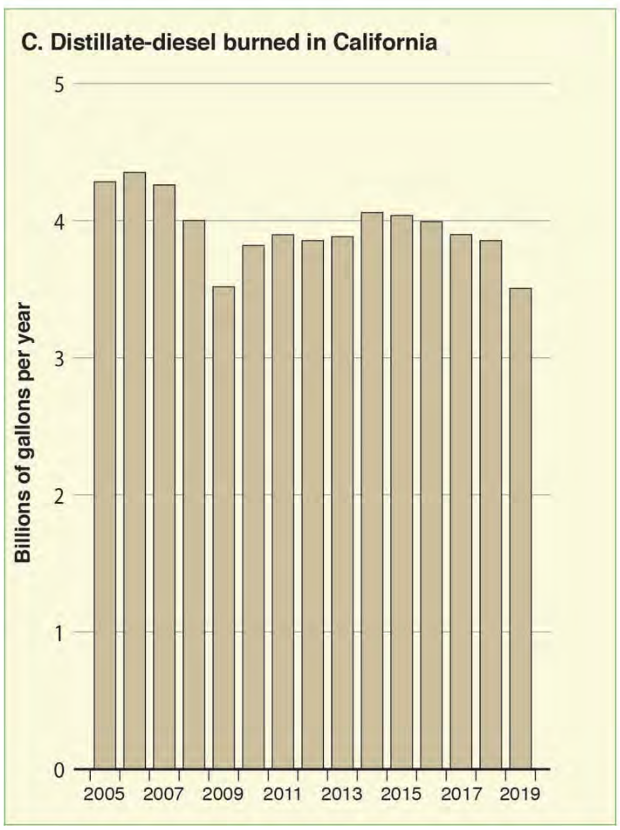
[1] *<u>See</u>* Attachment B, comment O12, Section III.
[2] Master Response 1 at 3-5 to 3-9.
[3] *<u>See</u>* Comment O12 Attachment C at 16 to 20, 36 to 40.
[4] Defined here as the US Energy Information Administration (USEIA) defines operable utilization rate, capacity utilization represents the utilization of atmospheric crude distillation units, and is calculated by dividing the gross input to these units by the operable calendar day refining capacity of the units.
[5] *<u>See</u>* Attachment 13 to Comment O12 Attachment C, and the Fuel Watch Data Update accompanying the technical supplement to the comments submitted by Natural Resources Defense Council to the Planning Commission dated March 22, 2022 (NRDC Comments).
[6] *<u>See</u>* Attachment 16 to Comment O12 Attachment C; *<u>see</u> also* U.S Energy Information Administration: Washington, D.C. *Refinery Capacity Data by individual refinery as of January 1, 2021;* www.eia.gov/petroleum/refinerycapacity

utilization[7] databases. Data shown in Chart 1C, discussed below, were taken from the California Air Resources Board fuel activity inventory.[8]

[7] *See* Attachment 16 to Comment O12 Attachment C, and the Capacity Utilization Data Update accompanying the NRDC Comments.
[8] *See* Attachment 14 to Comment O12 Attachment C.







Charts 1. California refineries over-built.

Fully 15 to 17 percent of statewide refining capacity that had not yet been decommissioned sat idle over the period from 2014 to 2019, the most recent six years before the COVID-19 pandemic.

A. Rolling ten-year mean utilization of operable crude refining capacity in California (red) and the U.S. West Coast (brown). California hosts most of West Coast refining capacity. Data are provided.[5–7]

B. Rolling five-year mean utilization of operable capacity for the same period, 2005–2021.[5-7]

C. Total petroleum distillate fuels including diesel burned in California annually from 2005 to 2019, the most recent year when the state reported complete data.[8] Chart does not include jet fuel or biofuels.

Declining West Coast petrofuels demand is one factor idling refining capacity. Continued consolidation of assets in fewer, larger plants is another. In Los Angeles, Marathon Corp. expanded what is now the largest West Coast refinery before closing its Martinez refinery. Now Marathon has 38 percent more statewide refining capacity in 2022 than it had in 2010, *despite* closing its Martinez refinery in 2020.[3]

Thus, the direct and objective indicator of refining overcapacity, operable capacity that sits idle, shows it is worsening (see Chart 1A) making any restart of crude refining less and less plausible.

Another observation illustrated by this chart, that the West Coast refining capacity utilization trend mirrors that in California but is not yet as low (*Id.*), further reveals the severity of the refining overcapacity problem in California.

Moreover, Chart 1A shows that instead of closing the gap between refining capacity utilization in California and that of the West Coast when Marathon shuttered the Martinez refinery in April 2020, the gap widened (*Id.*). This is consistent with and further strengthens the evidence its huge Los Angeles refining expansion, which worsened the statewide overcapacity problem Marathon shares, and leaves now with more California refining capacity—even after it shuttered crude refining at Martinez—than it had in 2010,[9] led Marathon to shutter its Martinez refinery.

As to the assertion that rising California petroleum fuels demand will result in restarting the crude refinery, the FEIR observes that in-state gasoline demand has declined since 2005,[10] and Chart 1C reveals that, when data from 2005 through 2008 the FEIR excluded from Figure 3-2 is considered, like gasoline, in-state distillate-diesel demand has declined since 2005.

The FEIR provides no relevant factual evidence for its assertion that the shuttered Martinez crude refining operations will restart due to future in-state demand for petroleum fuels.

Permit retention is <u>not</u> evidence for crude refining restart

The FEIR assert that retention of project site permits it lists in Table 3-1 is evidence the crude refinery would restart absent the project. It is not, because there are other reasons for Marathon to hold onto permits, which the FEIR does not disclose, evaluate or address in substantive terms.

In fact, there are several obvious reasons why Marathon would retain most, or all of the permits listed in Table 3-1 that are independent from any crude refining restart or plans for that restart. Its lease for the Avon and Amorco marine terminals would be needed for its currently existing petroleum storage and transfer equipment and operations at the site, and would be needed to implement its proposed project. BAAQMD permits in the record show these now-existing storage and transfer activities, marine terminals, and many existing on-site emission sources would require permits now, and would require permits for existing refining equipment to be repurposed for biofuel processing should the project proceed. Other onsite terminal and tank farm (SWRCB) stormwater discharge (RWQCB), hazardous waste (CDTE, CCHC), fire engine and nonvehicular source (CARB), and potable water (CCHC) activities that are ongoing now, will occur should the project proceed, or both, appear to require permits or fees independently from a restart of crude refining operations at the site. Simply assuming that the permits it lists can have no other purpose than crude refining, as asserted in the FEIR is not evidence.

The FEIR provides no relevant factual evidence for its assertion that the shuttered Martinez crude refining operations will restart.

[9] <u>*See*</u> Comment O12 Attachment C at 16 to 20, 36 to 40.
[10] FEIR at 3-8.

Operating fewer other equipment components is not evidence the project will prevent or mitigate significant potential hydrogen-related process hazard or flaring impacts.

Master Response 5 includes a vague assertion that the project would prevent or reduce process hazards and flaring by using fewer equipment components outside the hydro-conversion units to be repurposed than did the historic refining operation. Perhaps the only specific example to explain this assertion that is given in the FEIR refers to fewer process furnaces which will not consume as much fuel.[1] In fact, this type of reduction in the numbers of interconnected and interrelated equipment and process units in the new biorefinery could *cause* impacts by contributing to specific process and flaring hazards in hydro-conversion reactors.[2]

Specifically, other refiners often rely on multiple large furnaces, heaters, or turbines that are net fuel gas consumers to control fuel gas imbalances and overpressures and mitigate resultant flaring. Reducing the number and fuel consumption capacity of fired sources such as the furnaces the FEIR referenced, other heaters and turbines. Further, the reason given for the reduced firing implicates project process units—hydro-conversion process units—that are large net fuel gas producers, thus potentially worsening fuel gas imbalance hazards by adding net gas producers while subtracting net gas consumers.

Review of causal analysis reports for the frequent environmentally significant refinery flare incidents provided in DEIR comment[3] would reveal substantial evidence for the potential significance of removing this de facto process hazard and flare minimization safeguard.

Moreover, Marathon has identified this hazard to air quality officials outside the present CEQA review—the need fuel gas consuming equipment to prevent and mitigate fuel gas imbalance flaring and limitations of sufficient fuel gas consumers to do so—in far more specific detail than provided in the DEIR and FEIR. It currently approved Flare Minimization Plan, which shows Marathon has identified this same flaring cause and discussed it more candidly outside the EIR, accompanies the technical supplement.[4]

Thus, in effect, the FEIR responds to comment in a manner that, the project proponent has previously stated to another agency, could increase the significance of project flaring impacts which the DEIR failed adequately to evaluate and mitigate. The EIR as proposed is deficient for this reason alone.

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[1] FEIR at 3-43.
[2] *See* Comment O12, Attachment C, part V for details of hydrogen-related and damage mechanism hazards.
[3] *See* Comment O12, Attachment C, part V and Attachment 26 thereto.
[4] Marathon FMP, 2020. Marathon Martinez Refinery, Tesoro Refining & Marketing Company, Flare Minimization Plan – 2020 Update. Public Version. 1 October 2020. Appended hereto as "Marathon FMP."

Martinez Refinery

Tesoro Refining & Marketing Company LLC

A subsidiary of Marathon Petroleum Corporation

Flare Minimization Plan - 2020 Update

PUBLIC VERSION

(Confidential Information Redacted)

PUBLIC VERSION
(Confidential Information Redacted)

Marathon's Tesoro

Martinez Refinery

Flare Minimization Plan

October 1, 2020

2020 Annual Flare Update

Certification Statement

Based on information and belief after reasonable inquiry, I certify that the flare minimization plan is accurate, true and complete.

June Christman, Environmental Manager

9/30/2020
Date

Contents

Attachments

1.0 Executive Summary

This report covers the time period of July 1, 2019 through June 30, 2020. Marathon's Tesoro Martinez Refinery's (Martinez) Flare Minimization Plan (FMP) continues to provide an effective method to minimize flaring. Attachment 17 includes plots displaying daily average flare gas flow rates and daily average mass emissions of sulfur dioxide (SO2), methane, and non-methane hydrocarbons (NMHC), all averaged over calendar years. These plots continue to show significant reductions in flaring magnitude since 2001/2002, indicating that the flare minimization plan is effective. Flare gas flow rate for this reporting period has been reduced by about 92% since 2001/2002. In addition, emissions of NMHC, SO_2, and methane also have been significantly reduced since 2001/2002. Of the seven reportable flaring events which took place during this reporting period, one was related to emergency situation (classified by the Regulation 12-12-201 definition), and the remaining six events were classified as non-emergency situations. The emergency situation resulted from the 4.5 magnitude earthquake centered in Pleasant Hill, California. The non-emergency events were all related to unit shutdowns or flare gas imbalances and were necessary to prevent an accident, hazard or release to atmosphere, and thus are covered within this FMP.

Due to reduced market conditions stemming from the 2020 COVID-19 pandemic, the Martinez refinery commenced the reduction of operations to an idle state on April 28, 2020. This reduction was safely completed in the following weeks, but the elimination of recycled flare gas consumers resulted in an increase of waste gas and recovered vapor being routed to the main refinery flare system. These increased vapor and waste gas flows in 2020 have resulted in lower reductions than have been accomplished in previous years, however waste gas routed to the main flare system is expected to decrease once the safe decontamination of idle process units and equipment is completed. This event is further discussed in section 3.4.1 "Maintenance Activities Including Startups and Shutdowns". In August 2020, the decision was made public that Marathon's management teams will idle the Martinez refinery indefinitely. This decision will necessitate changes to the flare minimization practices at this site, which will be reflected in the 2021 update to this plan.

2.0 FMP Background Information

2.1 Regulatory Background

Regulation 12, Rule 12, was adopted by the Bay Area Air Quality Management District (BAAQMD or the District) on July 20, 2005. The purpose of this regulation is to reduce emissions from flares at petroleum refineries. This flare minimization plan is provided pursuant to, and is consistent with, the requirements of that regulation. This plan outlines the efforts that have been and will be taken prior to situations that could be expected to lead to flaring, as well as actions that will be taken should unexpected flaring occur. Some of these actions are already in place and have led to significant reductions in flaring. The remaining actions will minimize flaring to the extent that refinery operations and practices will not be compromised with regard to safety. The key tools utilized to accomplish the minimization of flaring are careful planning to minimize or eliminate flaring, coupled with an evaluation of the cause of any flaring events that do still occur. Using this approach, an understanding of the events leading to a flaring event can then be incorporated into future planning and flare minimization efforts. This plan also examines the costs and benefits of potential equipment modifications to further increase flare gas recovery.

2.2 General Overview of Flare Systems

Refineries process crude oil by separating it into a range of components, or fractions, and then rearranging those components to better match the yield of each fraction with market demand. Petroleum fractions include heavy oils and residual materials used to make asphalt or petroleum coke, mid-range materials such as diesel, heating oil, jet fuel and gasoline, and lighter products such as butane, propane, and fuel gases.

Petroleum refineries are organized into groups of process units (units), with the general goal of maximizing the production of the mid-range (gasoline and diesel) materials. Each unit receives a set of feed streams, and in turn, produces a set of product streams with the composition changed (or upgraded) as one step toward production of an optimal mix of refined products. Many of these processes operate at elevated temperatures and pressures, and a critical element of safe design is having the capability of releasing excess pressure in a controlled manner, via relieving devices, to the flare header. These processes also produce and/or consume materials that are gases at atmospheric pressure. As a final step in processing, many units provide treatment to products and/or byproducts in order to conform to environmental specifications, such as reduced sulfur levels of various fuels.

Refineries are designed and operated so that there will be a balance between the rates of gas production and consumption. Under normal operating conditions, essentially all gases that are produced are routed to the refinery fuel gas system, allowing them to be used as fuel for combustion equipment such as refinery heaters and boilers, Cogen, etc. Typical refinery fuel gas systems are configured so that the fuel gas header pressure is maintained by using imported natural gas to make up the net fuel demand. This provides a simple way to keep the system in balance so long as gas needs exceed the volume of gaseous products produced. Some additional operational flexibility is typically maintained by having the ability to burn other fuels such as propane or butane, and having the capability to adjust the rate of fuel gas consumption to a limited extent at the various refinery users (e.g. heaters, boilers, cogeneration units, steam turbines). The refinery typically stores propane and butane in pressure vessels, but can store propane and butane in railcars (if available) for additional storage capacity of these alternate fuels. A description of the wet gas, fuel gas, and flare gas recovery systems is provided in Attachment 1.

A header for collection of vapor streams is included as an essential element of nearly every refinery process unit. These are referred to as "flare headers", as the ultimate destination for any net excess of gas is a refinery flare. The primary function of the flare header is safety. It provides the process unit with a controlled outlet for any excess vapor flow, nearly all of which is flammable, making it an essential safety feature of every refinery. Each flare header also has connections for equipment depressurization and purging (as required by BAAQMD regulation) related to maintenance turnaround, startup, and shutdown, as well as pressure relief devices to handle upsets, malfunctions, and emergency releases.

Typical flare header design incorporates a knockout drum for separation of entrained liquid at the unit boundary. This minimizes the possibility of liquid being carried forward to the flare or flare gas compressor. Liquid will result in mechanical damage to most types of compressors and cannot be safely and completely burned in a flare.

The vapor stream from the unit knockout drum is then routed to the central refinery flare gas recovery system. A typical central refinery flare system consists of a series of branch lines from various unit collection systems which join a main flare header. The main flare header is in turn connected to both a flare gas recovery system and to one or more flares. Normally, all vapor flow to the flare header is recovered by a flare gas recovery compressor, which increases the pressure of the flare gas allowing it to be routed to a gas treater for removal of contaminants, such as sulfur, and then to the refinery fuel gas system. Gas in excess of what can be handled by the flare gas recovery compressor(s), the treater(s), and/or the fuel gas system end users flows to a refinery flare so it can be safely disposed of via combustion.

A flare seal drum is typically located in the line to the flare to serve several functions. A level of liquid, generally water, is maintained in the seal drum to create a barrier which the gas must cross in order to get to the flare stack. The depth of liquid maintained in the seal determines the pressure that the gas must reach in the flare header before it can enter the flare. This creates a positive barrier between the header and the flare, ensuring that so long as the flare gas recovery system can keep pace with net gas production, no gas from the flare header will flow to the flare. It also guarantees a positive pressure at all points along the flare header, eliminating the possibility of air leakage into the system. Finally it provides a positive seal to isolate the flare, which is an ignition source, from the flare gas header and the process units. Some flare systems combine multiple flares with a range of water seal depths, effectively "staging" operation of the various flares.

Gases exit the flare via a flare tip which is designed to promote proper combustion over a range of gas flow rates. Steam or air is often used to improve mixing between air and hydrocarbon vapors at the flare tip, so as to improve the efficiency of combustion and reduce smoking. A continuous flow of gas to each flare is required for two reasons. First, natural gas pilot flames are kept burning at all times at the flare tip to ignite any gas flowing to the flare. Additionally, a small purge gas flow is required to prevent air from flowing back into the flare stack. The facility typically uses natural gas as the purge gas, but in some cases nitrogen is also used as purge gas to the flare. The pilot and purge gas flow rates for the main flare system and the ammonia plant flare are determined using an orifice calculation based on the size of the orifice located in each line, and the pressure of the line upstream of the orifice. The pilot and purge gas flows for 50 Unit flare are measured using flow meters.

To help ensure that refinery flares always operate with high combustion efficiency, a new EPA standard requires the Martinez Refinery to maintain the net heating value of flare combustion zone gas (NHVcz) at or above 270 British thermal units per standard cubic feet (Btu/scf) determined on a 15-minute block period basis when regulated material is routed to the flare for at least 15-minutes.

Although this numerical limit is new, Martinez Refinery has historically maintained good combustion and prevented flare flame-outs by adjusting steam rates at the flare tip and adding natural gas to the flare gas at various locations in the header system when needed. For example, during turnarounds natural gas may be added to flare gas header system to ensure good combustion of flare gases during periods of high nitrogen and/or steam purges of units to the flare header. The vessel purges are used to clear hydrocarbon from vessels prior to opening to atmosphere, and the flare header system is equipped with manual valves at numerous locations that can be adjusted to increase supplemental natural gas.

In the past, Operations would communicate with the Flare operator to adjust natural gas addition. The automation of natural gas addition decreases response time and assures high combustion efficiency. This automation was completed for all refinery flares in compliance with the aforementioned Consent Decree and Refinery Sector Rule (RSR)

The sources of normal, or base level, flow to a refinery flare gas collection system are varied, but in general result from many small sources such as instrument purges, pressure control for refinery equipment items (e.g. overhead systems for distillation columns), or leaking relief valves. Added to this low level base load are small spikes in flow from routine maintenance operations, such as clearing hydrocarbon from a pump or filter by displacing volatiles to the flare header with nitrogen or steam. Additional flare load can result from various other process functions, often related to operation of batch or semi-batch equipment (e.g. drum depressurization at a delayed coking unit). An example of a "batch" operation would be occasional (e.g. once/shift) venting of compressor snubbers. This is done to remove any liquid that may accumulate in the snubbers. The snubbers are drained to the flare knockout pot until any liquid is withdrawn, and a small amount of gas goes into the knockout pot, which then goes to the flare system. This small amount of gas goes to the flare system and is normally recovered via the flare gas recovery system (to fuel gas).

Similarly, maintenance conducted on equipment in LPG service would result in a batch operation to flare. The LPG is pumped from the equipment to the extent possible. To finish preparation of the equipment for opening, the last remaining LPG would be vented to the flare. Another example would be at the Hydrogen Plant, where copper impregnated activated carbon drums are used to remove trace sulfur compounds from the treated feed gas prior to going to the Steam Methane Reformer furnace. Each of these carbon drums is regenerated by using a back-flow configuration of 600 psi steam to remove the trace sulfur compounds from the carbon bed, with the resulting stream venting to the flare header. This operation is typically performed once per week.

Scheduled maintenance activities can result in higher than normal flow of material to the flare. During equipment maintenance, the equipment and associated piping must be cleared of hydrocarbon before opening for both safety and environmental reasons, including compliance with BAAQMD Regulation 8 Rule 10. Typical decommissioning procedures include multiple steps of depressurization, and purging with nitrogen or steam to the flare header.

Although maintenance-related flows can be large, the design and sizing of refinery flare systems is without exception driven by the need for safe disposal of much larger quantities of gases during upsets and emergencies. A major emergency event will require the safe disposal of a very large quantity of gas and hydrocarbon materials during a very short period of time in order to prevent a catastrophic increase in system pressure. The flow that the flare system could be called upon to handle during an event of this type is several orders of magnitude greater than the normal or baseline flow rate. This FMP outlines the approach that Martinez has developed to manage and minimize flaring events, without compromising the critical safety function of the flare system.

3.0 Flare Minimization Plan

3.1 Technical Data – Description of Martinez Flaring Systems

The following sections describe the sizing and operating parameters for the components of the Martinez flaring system.

3.1.1 Flare System & Control Descriptions

Main Flare System

Flare Headers

In the main refinery, there are currently three flare headers (with diameters of 42" and two of 48"), available for collection of various vent gas sources. These four flare headers are cross connected at various points, acting in practice as one interconnected flare header system. The flare headers route vent gases from process units to the flare area, where recycle compressors reprocess as much waste gas as possible. Due to a portion of one of the flare headers nearing end of life, a new flare header was installed to replace it.

Flare Area

The vent gas flows through the flare headers to a collection of knockout pots and water seal pots in the flare area. Knockout pots are vessels that remove any entrained or condensed liquid. The gas then goes to a water seal pot. The water seal pot is a vessel that prevents the vent gas from entering the flares until the pressure in the flare headers exceeds the water level in the seal pots.

Flares

The main flare system is comprised of six flares. These are the North Steam Flare, South Steam Flare, West Air Flare, East Air Flare, Coker Flare, and the Emergency Flare.

The flare source numbers, capacities (per engineering relief calculations) and construction date are provided in the table below:

Flare Name	Source Number	Capacity (MMBtu/day)	Construction Date
East Air Flare	S-854	45,600	1983
North Steam Flare	S-944	64,800	1955
South Steam Flare	S-945	64,800	1955
Emergency Flare	S-992	316,800	1983
West Air Flare	S-1012	66,120	1976

Coker Flare	S-1517	588,300	2007

Additional physical parameters for each flare including the flare height, pipe diameter, number of pilots and number of steam injection nozzles is provided in the table below:

Flare Name	Height (ft.)	Pipe Diameter (in.)	No. of Pilots	No. of Steam Injection Nozzles
East Air Flare	75	24	3	0
North Steam Flare	28	24	3	8
South Steam Flare	28	24	3	8
Emergency Flare	75	48	4	0
West Air Flare	81	24	3	0
Coker Flare	200	42	3	64

The steam flares (North and South) use steam to aspirate air and improve smokeless operation. Similarly, the air flares (East and West) use air to improve smokeless operation. The Emergency Flare is designed to only operate during very high vent gas flows, such as during a total power failure. Therefore, it is not designed for smokeless operation, since there would not normally be power (for air assist) or steam available during such situations. The flares are "staged," that is, they are designed so that vent gas is sent to the flares progressively as the amount of gas increases. This is accomplished by setting the water levels in the seal pots at different levels. The typical order that vent gas is sent to the flares is: the steam flares, the Coker Flare, the East Air Flare, the West Air Flare, and the Emergency Flare. The order of the flares may change based on operational considerations and maintenance schedules for the flares. Then the flare order will change as needed. However, in any scenario, the emergency flare is always set to be last. The order is set through the use of water seal pots with varying levels of water in each seal pot that sets the flare order. The typical water seal heights are as follows:

- Steam Flares: 24"
- Coker Flare: 30"
- East Air Flare: 32"
- West Air Flare: 35"
- Emergency: 174"

By adjusting these water levels, the vent gas automatically goes to one or more flares. As the flow to the flare headers increases, the flare header pressure increases and exceeds the water level pressure, blowing through the water seal and going to the flare. As the flare header pressure decreases, the water seal is reestablished, and flow to the flare(s) stops. A small amount of natural gas is added to the flare line, after the water seal pot, to maintain a positive pressure to ensure that air does not enter the flare lines. A small amount of natural gas is also used for flare pilots to ensure proper combustion should a flaring event occur. There is no normal daily flow to the flare (i.e. the flare gas recycle compressors typically recover all of the gas being sent to the flare area). The 2005 average flow to the refinery main flare system was 0.8 MMSCFD. The purge gas sent to the flares in the refinery main flare system is natural gas and the 2005 average flow of purge gas to those flares was 0.13 MMSCFD.

Potential for Temporary Thermal Oxidizers and Portable Flares

To add flexibility during maintenance periods, the Martinez Refinery will utilize portable thermal oxidizers, portable flares or temporary H2S removal equipment. The use of such equipment would be during flare turnarounds, 5 Gas Plant turnarounds or other unforeseen mode of operation. The refinery normally schedules flare outages to coincide with process unit shutdowns.

Temporary H2S removal equipment for the 5 Gas Plant turnaround includes knockout pots, vent gas compression, caustic scrubbers, piping, and associated instrumentation. Please see permit condition for additional information.

Flare Gas Recovery System

At the flare area, incorporated into the flare system, is a flare gas recovery system. The system is comprised of a recycle compressor and a spare compressor (CP-539 and CP-540 rotate between being in operation and on cold standby as a spare) that draws flare gas from the flare headers and compresses the flare gas, sending it to the No. 5 Gas Plant (GP). At the No. 5 GP, the gas is further compressed and sent to an amine treating system for removal of sulfur compounds and is then sent to the fuel gas system. See Attachment 1 for additional details regarding the flare gas recovery, fuel gas, and wet gas systems.

Under normal refinery operating conditions, the flare gas recovery system recovers all of the vent gas. The flare gas recycle compressors have a nameplate capacity of 4.0 MMSCFD each and the maximum observed capacity is about 5.0 MMSCFD. The maximum design temperature for these compressors is 160° F on the compressor discharge. The compressor gas design molecular weight (MW) was based on three cases: a low MW case of 5.8, a typical MW case of 17.9, and a high MW case of 25.9. No maximum molecular weight was specified in the design.

The spare flare gas recovery compressor is in cold standby to reduce the risk of losing both compressors due to an adverse event. For example, if a slug of liquid entered the flare gas recovery compressor system and the existing systems failed to shut down the compressor, the compressor could be seriously damaged. If the spare compressor was set to automatically start, the spare compressor could also be seriously damaged which would result in all recovery compressor capability being lost for weeks or longer. However, by keeping the spare compressor in cold standby, if one compressor shuts down, procedures require that the operator determine the cause of the compressor shutdown and resolve that problem before attempting to start the spare recovery compressor. It typically takes about 15 minutes to start the spare compressor and another 10 minutes to bring the compressor to full rate. This reduces the risk that one event would take out both recovery compressors. Clearly, losing the recovery capacity for a few minutes is preferable to the risk of losing the recovery capacity for weeks or longer.

Recently, a number of regulatory considerations have directed Martinez to work toward operation of the second flare gas recovery compressor when the capacity of the first compressor has the potential to be exceeded. As a preventative measure, the refinery now starts up the second compressor in order to recover more gases. Operating the second compressor as well as controlling the depressuring sequence during shutdowns, has dropped the amount of flaring significantly.

However, as noted above, the risk of losing both flare gas recovery compressors increases. In addition to the situation described above, if the oxygen content of the flare gas exceeds 3%, both recovery compressors would be shut down, regardless of the operating mode, to ensure an explosive mixture does not occur in the compressors. Various other conditions can also result in the shutdown of both recovery compressors. Situations that would lead to the flare gas recycle compressor tripping off-line include but are not limited to:

- A low level in the flare gas compressor discharge knockout pot as indicated by a switch on the pot (LSLL-1124 and 1136) or by the transmitter on the pot (L-1125 and 1137) will trip the compressor. If the liquid level is too low, seal water circulation could be lost which would lead to damaging the compressor, the seal water pumps, or the seal water cooler.

- A high level in the flare gas compressor discharge knockout pot as indicated by the transmitter on the pot will trip the compressor (L-1125 and 1137). If the liquid level is too high, liquid could back into the compressor suction which would lead to a failure of the compressor.

- A low pressure on the suction line to the compressors will cause the compressor to trip. If a vacuum is pulled on the flare line, air could be drawn into the flare header causing the potential for an explosive mixture in process equipment. (PT-1120, PT-1130 and 1131)

- A low flow of seal water back to the compressor will trip the compressor. If the liquid level is too low, seal water circulation could be lost which would lead to damaging the compressor, the seal water pumps, or the seal water cooler. (F-1121 and 1133)

- A high level on the compressor suction pot (V-107) will shut down the compressor. Liquid carry over into the compressor would result in damage to the compressor. (L-1160)

- A high concentration of oxygen in the flare gas stream will cause the compressors to shut down. High oxygen levels in the flare gas could result in an explosive mixture and increased fouling in process equipment. (19-ASHH1161, 1162, 1163)

- A high compressor discharge pressure will cause the compressor to trip. This is to prevent damage to the compressor and associated equipment.

- A high pressure on the extraneous knockout pot at No. 5 GP will cause the compressor to trip. This is to prevent a recycle loop from occurring since the main accumulator at No. 5 GP will relieve to the flare system at 10 psig. (3-PSHH-4677/4675 1 of two voting)

- High bearing temperatures on the compressor (T-1145, 1146, 1147, and 1152) or on the compressor motor (T-1171, 1172, 1173, and 1174) will cause the compressor to trip. Continued operation during imminent bearing failures could result in catastrophic failure of the compressor.

- An electrical failure on the compressor motor/starter circuitry will cause the compressor to trip. Such an electrical problem could cause further damage to the motor or a result in a fire.

- If any one of the stop buttons are pushed, the compressors will trip. There is one located in the Thermal Area control room, one located at No. 5 GP, and one located at the local panel for the compressor.

There is no formal written procedure describing when it is permissible to re-start a flare gas recycle compressor, however, in most cases, the operator would restart the compressor or start up the other flare gas recycle compressor after the reason for the compressor trip was understood and corrected. The reason for the compressor trip must be identified and corrected prior to restarting either compressor to ensure that any potential safety or equipment hazards are properly addressed. Should the determination be made that the cause of the compressor trip was a mechanical breakdown of that specific compressor (and no other safety or equipment hazard existed), the other flare recycle compressor would be started. When neither of the flare gas recycle compressors are operating, the gases in the flare system will go to the flares.

The manufacturer's recommended frequency and schedule for the flare gas recycle compressor repair and maintenance is provided in Attachment 2. However, the maintenance recommendations contained in the Original Equipment Manufacturer (OEM) manual for the flare gas compressors are from a generic manual that the OEM supplies with all their products and so many of these recommendations are not completely consistent with the requirements of these specific compressors. The practices followed at Martinez are based on Industry Best Practices and are focused on improved equipment reliability. For example, Section 4-2 paragraph a., describes lubricated couplings which are not present on the flare gas recycle compressors at Martinez. The Martinez compressors utilize a disc-pack dry coupling. Additionally, Section 4-2, paragraph b & c, Section 4-3, and Section 4-4 describe frequency and procedure by which to lubricate various bearings and couplings. For the Martinez compressors, all bearings are fitted with automatic grease lubrication devices which inject a measured amount of grease at specific time intervals. This provides the best lubrication for the bearings. As a third example, Section 4-5 describes preventative maintenance procedures for stuff box packing within the compressor. The flare gas recycle compressors at Martinez do not have packing. Mechanical seals are required due to the potentially sour (sulfur containing) hydrocarbon gases contained in the process.

As part of the Predictive Maintenance program, Martinez monitors the vibration levels on these compressors monthly when they are in operation. In addition, the lubricators are checked monthly, as part of the vibration rounds, and semi-annually as part of the lubrication rounds. Martinez believes this maintenance regime is better suited to the flare gas recycle compressors.

The location of monitors that could trip off the flare gas recycle compressors are identified on the flare system process flow diagram (PFD). They are noted as a "T" near a circled item. The abbreviations used in circled items on the PFD are:

P	Pressure
T	Temperature
F	Flow
L	Level
A	Analyzer (typically oxygen)
RO	Restriction Orifice

The current trip settings are also included on the PFD. For example, the compressor knockout pot trip temperature is 160° F, the compressor motor bearings temperature trip is 180° F, and the compressor case temperature trip is 220° F. (The recovered flare gas temperature typically ranges between 80 and 120° F, and based on current knowledge, there has not been a flare event associated with the loss of the flare gas recovery compressors due to a high temperature trip of those compressors.

The only flare gas compressor trips that are not included on the PFD are:
1) the stop switches for the compressors, as noted above,
2) the high pressure on the extraneous knockout pot at No. 5 GP (which trips at 7 psig) and,
3) the electrical failure monitor on the compressor motor/starter circuitry.

These have not been included on the PFD because the equipment is not located on this PFD (i.e. the No. 5 GP and compressor motors) and would unnecessarily clutter the PFD.

The flare gas recovery compressors do not have a nitrogen content trip and the flare gas recovery compressors can handle essentially any amount of nitrogen in the gas. However, the amount of nitrogen that can be handled in the fuel gas system (which is the ultimate disposition of this gas) is limited. There is no defined nitrogen content specification for the fuel gas. The compressors are shut down for high nitrogen concentration if they are adversely affecting the heat energy value of the fuel gas or the operation of the No. 5 GP wet gas compressors.

ARU Flare

The Ammonia Recovery Unit (ARU) Flare is connected primarily to the ARU but also to the SCOT and DEA units. The majority of the flaring situations result from ARU operations. The ARU Flare is equipped with a MW analyzer which is used to provide the operators with an indication of the flare gas composition. The flare gas composition, depending on the value, can assist Operations in predicting whether a potential flaring event is likely. Corrective action can be taken to reduce and/or avoid the resulting flare events.

The ARU Flare is equipped with a relief scrubber upstream of the ARU Flare stack. The flare stack is also equipped with a knockout pot and water seal to remove entrained liquids, provide some additional scrubbing capacity and prevent backflow from the flare into the flare header.

The flare source number, capacity (per engineering relief calculations) and construction date are provided in the table below:

Flare Name	Source Number	Capacity (MMBtu/day)	Construction Date
ARU Flare	S-1013	6,408	1983

Additional physical parameters for the flare including the flare height, pipe diameter, number of pilots and number of steam injection nozzles is provided in the table below:

Flare Name	Height (ft.)	Pipe Diameter (in.)	No. of Pilots	No. of Steam Injection Nozzles
ARU Flare	160	84 (bottom) 45 (mid)	3	0

<u>ARU Flare Relief Scrubber</u>

Gases from the relief header are fed to the scrubber where they are contacted with a continuously circulating stream of ammonia solution. This solution absorbs hydrogen sulfide (H_2S) and ammonia with the resulting overhead vapor flowing to the flare. Circulation of the ammonia solution is maintained by a scrubber pump on a continual basis. Should a large relief load be present, a second larger circulation pump is started which increases scrubbing capacity by 2.7 times. The rich circulating solution is purged from the scrubber and sent to the feed mixing drum for reprocessing through the ARU. The scrubber itself is designed with two compartments. The first is used during normal operating conditions whereas the second is used during upset conditions when extra H_2S and ammonia absorbing capacity is required.

<u>ARU Flare Description</u>

The flare system is comprised of the knockout drum, the water seal, and flare stack. The overhead vapors from the relief scrubber are fed to the knockout drum. This drum removes any entrained liquids and sends them to the feed mixing drum for reprocessing. The vapors from the knockout drum then feed the flare seal pot which contains a water seal to prevent backflow from the flare into the scrubbing section. The liquid in the water seal is flushed on an as needed basis and make up water is provided by cold condensate from the ARU. The vapor leaving the seal pot then passes through a molecular seal which effectively prevents any air from entering the flare stack below the seal for extended periods of time. The seal is flushed with hot condensate to clean the seal pockets.

The flare tip employs natural gas fired continuously operated pilots. Pilots can be relit remotely in the control room or at a local panel if low temperature is detected. A backup system can also be used. The manually operated flare front generator uses instrument air mixed with natural gas that flows to the pilots to re-ignite them.

50 Unit Flare

The 50 Unit Flare system is comprised of a new collection header, flare gas recovery system knockout drum, a new liquid ring flare gas recovery compressor, and a flare. In addition, the existing 50 Unit wet gas compressors are also connected into the flare gas recovery system for periods of larger flow and as a backup for the new flare gas recovery compressor. The recovered gas is routed to the refinery fuel gas system at the No. 5 GP. Any recovered liquid in the knockout drum is cooled and pumped to the refinery recovered oil system.

The flare source number, capacity (per engineering relief calculations) and construction date are provided in the table below:

Flare Name	Source Number	Capacity (MMBtu/day)	Construction Date
50 Unit Flare	S-1524	672,000	2010

Additional physical parameters for the flare including the flare height, pipe diameter, number of pilots and number of steam injection nozzles is provided in the table below:

Flare Name	Height (ft.)	Pipe Diameter (in.)	No. of Pilots	No. of Steam Injection Nozzles
50 Unit Flare	310	30	3	42

The steam flare uses steam to aspirate air and improves smokeless operation. The typical water seal height is 61".

3.1.2 Process Flow Diagrams

A PFD of the Main Flare System and associated vessel diagrams are provided in Attachment 3.

The PFDs of the 50 Unit Flare system and associated seal pot diagram are provided in Attachment 3A.

The PFDs of the ARU Flare system and associated seal pot diagram are provided in Attachment 4.

3.1.3 Description of Monitoring and Control Equipment

A description of the monitoring for the Main Flare System, the 50 Unit Flare System and the ARU Flare is provided below. The control for these flares is included in the flare system information in section 3.1.1 above.

Main Flare System Monitoring

<u>Flare Flow Monitoring</u>

The 42", 48", and 48" flare header flows are monitored by an ultrasonic flow meter located in each of the flare headers. Ultrasonic flow monitors are also installed in the outlet of the flare gas recovery compressors, the line to the Coker Flare, and on the flare line to the steam flares. This data is provided in monthly reports to the District.

Currently, the amount of vent gas being flared is determined by adding all the flare header flows (i.e. the 42" and two 48" headers) and subtracting the recovered vent gas flows from the flare gas recycle compressors (also known as the flare gas recovery compressors). During low flows of vent gas to the flares, the Steam Flare flow meter is used, since the Steam Flares are the first flares to see flare gas. Martinez believes that this provides the best accuracy at the lower flare flow levels.

During these low flare flow situations (where the gas is only being sent to the steam flares), Martinez uses the steam flare flow meter to determine the amount of gas being flared. The output from this meter is compared to seal pot monitoring (i.e. seal pot water level vs. flare header pressure) to determine the flow. When the seal pot water level (expressed in inches of water column) exceeds the flare gas pressure at the seal pot (also expressed in inches of water column), this indicates that there is insufficient pressure in the flare header to go through the water seal, and there is no flow to the flare. In this case, there is zero flow for the flare.

By January 2019, to comply with the Consent Decree and Refinery Sector Rule, individual flare gas flow meters were installed after the seal drums at the East Air Flare, West Air Flare, and Emergency Flare. The East Air, West Air and Emergency Flare flows are monitored by Optical Scientific Inc. flow meters.

To address flows to the flare header system, Martinez employs various monitors to determine the source of flare gas to the system. Several flow meters are used to identify the process area or unit that is generating flare gas to assist in determining and reducing flow from that source. In addition, other operating parameters are monitored (e.g. pressure, valve position, etc.) to identify the source of flare gas. By routinely monitoring these parameters, proactive actions can be taken to identify the cause of the additional vent gas and, to the extent possible, take appropriate action. This has proven to be an effective method to minimize flare gas flows.

<u>Flare Gas Composition Monitoring</u>

As part of Martinez's plan to comply with NSPS Ja requirements, the flare gas composition monitoring scheme for the refinery was revised. Each flare in the main flare system and 50 Unit flare has an H_2S analyzer to monitor the concentration in the vent gas. The total sulfur content of the flare gas is analyzed by a continuous total sulfur monitor in the north and south steam flare line, since these are the flares that are normally first in the refinery staged flare system. When the Coker Flare is staged first, the Coker Flare H_2S analyzer is used.

For the Consent Decree, Martinez purchased gas chromatographs (GC) to measure the hydrocarbon content of the vent gas. Martinez certified these analyzers in 2017. We perform manual sampling when the GC's are not functioning. The hydrocarbon data is provided in monthly reports to the District.

<u>Video Monitoring</u>

In addition, cameras are used to obtain a visual record of each of the flares once per minute. These are archived as digital picture files (jpg format) and provided to the

District monthly on DVDs. Martinez has increased the number of flare pictures to meet the Consent Decree requirements of four pictures per minute.

Flare Seal Pot Level Monitoring
The water level in each of the flare seal pots is continuously monitored, along with the flare header pressure, near each seal pot. This data can be used to determine whether the water seals are intact as a way of determining whether any flaring is taking place.

Other Flare Monitoring
The flare pilots are also monitored via thermocouples to ensure that the pilot lights remain lit. In addition, the amount of pilot gas and purge gas is monitored and reported to the District in the flare monthly reports.

ARU Flare System Monitoring

Flare Flow Monitoring
The ARU Flare flow is monitored by a continuous ultrasonic flow meter. This data is provided in monthly reports to the District.

Flare Gas Composition Monitoring
Due to the potentially high ammonia and H_2S content of the flare gas, representative, worst case compositions are used to determine emissions, pursuant to Regulation 12-11-502.3.1a.

Video Monitoring
A camera records a visual record of the ARU Flare once per minute. These are archived as digital picture files (jpg format) and provided to the District monthly on DVDs.

Flare Seal Pot Level Monitoring
The water level in the ARU Flare seal pot is continuously monitored, along with the flare pressure. This data can be used to determine whether the water seal is intact as a method of determining whether any flaring is taking place.

Other Flare Monitoring
The flare pilots are also monitored via thermocouples to ensure that the pilot flames remain lit. In addition, the amount of pilot gas and purge gas is monitored and reported to the District in the flare monthly reports.

50 Unit Flare System Monitoring

Flare Flow Monitoring
The 50 Unit Flare flow is monitored by a continuous ultrasonic flow meter. This data is provided in monthly reports to the District.

Flare Gas Composition Monitoring
The sulfur content of the 50 Unit Flare header is monitored by a continuous monitor for H_2S. The hydrocarbon content of the flare header is taken manually during a flare event

and analyzed in Martinez's lab using a gas chromatograph to determine the hydrocarbon composition of the flare gas. This data is provided in monthly reports to the District.

Video Monitoring
A camera records a visual record of the 50 Unit Flare once per minute. These are archived as digital picture files (jpg format) and provided to the District monthly on DVDs.

Flare Seal Pot Level Monitoring
The water level in the 50 Unit Flare seal pot is continuously monitored, along with the flare pressure. This data can be used to determine whether the water seal is intact as a method of determining whether any flaring is taking place.

Other Flare Monitoring
The flare pilots are also monitored via thermocouples to ensure that the pilot flames remain lit. In addition, the amount of pilot gas and purge gas are monitored and reported to the District in the flare monthly reports.

The locations of flow meters, temperature and pressure indicators are shown on the PFDs included in Section 3.1.2 above. The locations of sample points and continuous emission monitoring (CEM) equipment are also shown on the PFDs included in Section 3.1.2.

3.2 Reductions Previously Realized

Over the last decade, Martinez has significantly reduced flaring. This has been accomplished predominantly by starting up the second flare gas recovery compressor on the main refinery flare gas system, and through improved awareness and management of the flare system to minimize flaring. From July 2002 to present, non-methane hydrocarbon flaring emissions have been reduced from about 2 tons per day to about 0.075 tons per day on average (based on 2020 data). This represents a reduction of about than 95%. In 2016 Martinez further increased its efforts in decreasing flaring. During planned events, Operations and Planning have staggered shutdowns to stay within the capacity of the two compressors. During unplanned shutdowns, Operations has increased their efforts to startup the second compressor and make adjustments to decrease streams to the flare. These efforts have greatly reduced the number of flaring events in 2016 through 2020.

Martinez has reduced flare flows due the following:

- Planned use of the Flare header will be coordinated to prevent exceeding the capacities of the flare gas recovery compressors to the maximum degree practicable.
- All discretionary venting to the flare header due to planned maintenance will be coordinated with the Shift Superintendent. Operations staff filling this role manage such venting to stay within the Compressor capacity to the extent feasible.

- Planned venting activities which are anticipated to exceed the capabilities of the primary compressor will include proactively activating the second Compressor to prevent flaring.
- Base load to the flare gas recovery compressors are monitored. If there is an increase in the amount of waste gas recovered on a daily basis, the refinery has a procedure to find the source and eliminate the flow. This proactive monitoring allows for additional recovery capacity to offset flaring during actual flare events due to emergencies or unforeseen circumstances.

Other actions that have been taken to reduce flaring include improved planning efforts related to maintenance turnarounds and operational changes to keep the fuel system in balance. Prior to maintenance turnarounds, Martinez has evaluated the potential flaring that could occur as a result of the turnaround and developed plans to try to eliminate or reduce flaring (see Section 3.3, Description of Planned Prevention Measures for more information on this process). Such plans consider whether vent gases generated during shutdown and maintenance can be routed to other closed systems first to minimize material sent to the flare system, and for those vent gases that must still be sent to the flare, whether venting to the flare more slowly would help to stay within the flare recovery system capacity.

The plans also consider the timing of the various unit shutdowns and purging opportunities to keep the rate to the flare gas system within the recovery capability. For example, during the last planned major maintenance activity, units were prioritized relative to when they could depressure to the flare system. The flare gas recovery compressor flow was monitored to stay within the system capacity, and additional vessel purging and depressuring was conducted as system capacity was available. It should be noted, however, that situations can occur when the volume of nitrogen required to properly clear the vessel (and catalyst) of hydrocarbon material for safe entry is such that it can exceed the flare recovery system capacity. In addition, such plans have considered the use of chemicals to improve initial hydrocarbon removal to reduce the time needed for steam out or purging to flare.

In addition, various actions have been taken as a result of causal analyses performed for flaring events. These actions are included in Attachment 5.

Operations also manages the fuel gas and hydrogen systems to keep the system in balance. Actions are taken to modify unit operations at fuel gas and hydrogen generating units to reduce gas make, if needed (such as changing unit rates and reducing FCCU temperature). In addition, actions are taken to try to increase hydrogen uptake and increase firing at furnaces to consume more of these commodities to keep the fuel gas and hydrogen systems in balance. Typically, the fuel gas system is kept in balance but there are situations when this is not the case. For short periods of time, upsets, malfunctions, emergencies, and other situations can result in the fuel gas system becoming imbalanced until the situation can be stabilized and unit operations can be adjusted to come back into balance. So, efforts to prevent fuel gas imbalance situations apply to all units at the facility whose operation may result in flaring associated with a fuel gas imbalance.

There can be longer-term situations where the fuel gas system is out of balance. For example, there can be situations where the fuel gas producing units are at minimum rate and the fuel gas system is still out of balance. Any further rate reductions would result in the units becoming unstable and pose a safety concern. Actions are taken to minimize the length of time that such situations occur. These situations are infrequent and are generally associated with equipment maintenance/turnaround. Therefore, the duration of maintenance activities is minimized (e.g. overtime authorized), consistent with the work scope and good safety and environmental practices.

Additional information on fuel gas system imbalances is provided in the Startup and Shutdown Process portion of Section 3.4.1, the existing Martinez vent gas recovery, storage, & scrubbing capacities portion of Section 3.4.2, and the description of the wet gas, fuel gas, and flare gas recovery systems provided in Attachment 1.

Beyond this, the Operations shift organization works to maintain good communication and coordination so that the flare gas compressor load is not exceeded. Actions have also been taken to minimize acid gas flaring through monitoring and alarming the molecular weight of the vent gas and taking appropriate action based on that information. An increase in the molecular weight can be an indication that there is an increase in H_2S in the relief header. By monitoring the molecular weight, the operators can be notified of a potential increase in H_2S to the relief header and make operating moves to address the situation more quickly (e.g. reducing H_2S stripping in the stripping column by reducing the stripping steam, which will reduce H_2S to the relief header), resulting in the prevention of or a reduction in acid gas flaring.

The reduction amounts discussed in this section are less than those presented in the 2019 update. This is due to the resulting from the April 2020 decision to place the Martinez refinery in an idle operating state. The amount of waste gas routed to the main flare system is expected to decrease once the safe decontamination of idle process units and equipment has been completed.

3.3 Planned Reductions

A table summarizing the actions currently planned to effect further reductions in refinery flaring is provided in Attachment 6. These items have been identified through flaring evaluations as potential ways to either directly reduce flaring or reduce the chance of a flaring event. The Alky Gas Turbine Replacement project, which replaced the gas turbine with an electric motor, reduced the baseline load to the flare gas recovery compressors due to an improved spillback control system and increased reliability.

Martinez worked on prevention measures to decrease flaring during 5 Gas Plant Turnaround, and to decrease the normal load to the flare gas recovery compressors.

A project identification number has been provided to allow the District to track these projects. The Approval for Expenditure (AFE) number or Project Tracking System (PTS) number has been provided. This is a unique number that is used for accounting purposes and follows the project. In addition, the estimated date of completion of the project has been provided. Please see attachment 6.

Acoustic monitoring on hydrocarbon pressure relief valves are required for the Consent Decree. As leaking components are found, they are added to the turnaround lists for repair. This helps reduce base flow to the flare gas recovery compressors.

As part of the flare causal analysis process, incident teams identified methods that may help to prevent a recurrence of the flaring incident. Many of these items are not key actions to prevent flaring but are actions that may have a potential (even slight) to prevent an incident from recurring. To be conservative, these items are identified because of a lack of information to rule them out as a potential contributing cause to flaring. For example, on the 2/17/2011 flaring incident, flaring was initiated as a result of an emergency shutdown of No. 1 Hydrogen plant, and the depressuring of both stages of the Hydrocracker due to loss of hydrogen from the No.1 Hydrogen plant emergency shutdown. The investigation for this event highlighted several contributing factors, and many of the corrective actions identified in this investigation are related to changes in control strategies, instrumentation, operating procedures, etc. which individually would not eliminate flaring but would potentially reduce the risk of a recurrence. This example illustrates that many of these actions may not directly cause flaring, however, Martinez is committed to studying each action to determine whether implementing them will result in the potential to minimize flaring.

In addition, various potential actions were identified as a part of flare causal analyses. These potential actions are under consideration and are, therefore, not truly "planned reductions" yet. These open action items may yet develop into flare reduction projects but not enough work has been completed yet for them to reach the point of being a planned reduction. These open action items really do not fit in either "reductions previously realized" or "planned reductions" sections. However, Martinez has provided information to allow the District to track these open action items and will include them in the planned reductions section in future FMP updates if they progress to that status. These items are provided in Attachment 7.

Marathon personnel have diligently pursued the completion of feasible actions which would eliminate situations and scenarios which have resulted in past flaring events. However, the August 2020 decision to indefinitely idle the refinery has resulted in outstanding action items previously presented in this plan being rejected since they are no longer applicable in the current operating scenario.

3.4 Prevention Measures

The following section discusses flaring prevention measures and practices utilized at Martinez.

3.4.1 Maintenance Activities Including Startups and Shutdowns

This section discusses refinery maintenance and turnaround activities and outlines measures to minimize flaring during both preplanned and unplanned maintenance activities.

Maintenance Activities

Maintenance activities can result in a higher than normal flow of material to the flare gas recovery system. In order to maintain process equipment, the first step is to clear the process equipment and associated piping of hydrocarbons before the system is opened to the atmosphere, for both safety and environmental reasons, in compliance with BAAQMD Regulation 8 Rule 10, (Process Vessel Depressurization). How this is accomplished depends on the physical properties of the hydrocarbons to be removed (vapor pressure, viscosity) and on the process details of the equipment that is to be maintained.

The first step is to recover as much of the hydrocarbon as is possible to another point in the processing prior to opening the equipment to the flare or the atmosphere. For example, liquid hydrocarbons can be pumped to tankage or another process system and gases under pressure may be depressurized to another process unit. Heavy hydrocarbons that are viscous at ambient temperatures are often displaced from the equipment to be maintained using lighter hydrocarbons, e.g. light cycle oil (LCO). The LCO can then be pumped from the equipment.

Although depressurization and pump-out can normally be used to remove the bulk of the hydrocarbon from the equipment, some residual material can remain. Following pump-out or depressurization to other process equipment, the next step in decommissioning involves sending the residual gas to a fairly low-pressure system that has the ability to accept a wide range of hydrocarbon materials, the refinery wet gas system, where available. This system recovers various gas streams in the refinery.

Lastly, any remaining hydrocarbon is sent to the lowest-pressure recovery system, the flare gas recovery system, so the hydrocarbon can be recovered as fuel gas. This remaining gaseous hydrocarbon can be purged to the flare using an inert gas such as nitrogen. Alternatively, nitrogen can be added to the equipment, increasing the internal pressure. The resulting mixture of nitrogen and hydrocarbon can then be released to the flare header. Steam can be substituted for nitrogen when heat, moisture, vessel temperature, and pressure do not constrain its use. For example, steam cannot be used to purge vessels in caustic service due to the potential for stress corrosion cracking. Steam also cannot be used for most reactors since it would damage the catalyst in the vessel. In addition, some vessels are coated internally for corrosion resistance and steaming cannot be used because it would result in a failure of the coating due to the heat. Substituting nitrogen with steam can produce some small reduction in flaring since the steam condenses in the flare line and is decanted into the refinery slops system, whereas the entire volume of nitrogen goes to the flare.

For any small amount of liquids remaining in equipment, steam or nitrogen are routinely used to push the liquid to the flare system knockout vessel(s). The liquid hydrocarbon and condensed steam are separated from the vapor phase and returned to the refinery's recovered oil system and to wastewater treatment either at the unit knockout drum or at the flare knockout drum. Nitrogen with hydrocarbon vapor continues on to flare gas recovery. Once the liquid hydrocarbon has been displaced, the flow of steam or nitrogen is continued to remove any residual hydrocarbon clinging to the equipment walls. Steam can be more effective for heavier materials as it increases their volatility by increasing temperature.

Generally, hydrocarbon can be effectively removed from vessels through pumping out the hydrocarbon and purging the vessel with nitrogen or steam. However, when this process is not adequate to clean the vessel for opening, proprietary solutions can be used to chemically clean the vessel. Also, these solutions typically contain materials that are somewhat more hazardous with respect to personnel exposure that nitrogen and steam. Therefore, when nitrogen and steam are effective, those methods are preferentially used.

When used, proprietary solutions are circulated, so that venting is not required. (Nitrogen and steam are once-through purging agents; when purging with nitrogen or steam, the systems being purged must be vented to a flare to prevent pressure from building.) The circulating solution is often filtered to remove contaminants, and fresh chemicals are added as required to maintain solution properties. When the system is clean, the solution is drained, and the equipment is typically flushed with water.

Examples of equipment that might be cleaned using proprietary solutions include pressure vessels, distillation columns, furnaces, and heat exchangers. System components often vary depending on maintenance needs.

Although these procedures eliminate hydrocarbon emissions to the atmosphere related to equipment opening, they require significant volumes of steam or nitrogen in order to be effective. This high flow rate of purge gas can create situations where flare gas recovery is not feasible. These situations relate either to a change in flare vent gas composition (change in molecular weight, heat content, or temperature) or to the increase in vent gas flow rate. Changes in the composition or temperature can be such that the compressors used to recover the vent gas are unable to properly compress the gas. Increases in vent gas flow rate can be such that the compressors cannot recover all the gas.

In addition, there are many process and reactor systems within the refinery that contain gases with a high hydrogen content. When this equipment is decommissioned by depressurization to the flare gas header, there can be a sharp decrease in the flare gas average molecular weight. This can also result in situations where flare gas recovery is not feasible due to composition or vent gas flow issues (i.e. the amount of flow may exceed the recovery capacity of the recovery system).

<u>Effect of Recovered Flare Gas on Downstream Equipment</u>

Gas composition can impact the operation of flare gas recovery equipment as well as equipment utilizing the recovered gas. Specifically:

- High nitrogen or hydrogen content can impact heaters, boilers, flare gas recovery compressors, and fuel gas compressors.
- Steam impacts knockout drums and compressors, while increasing sour water production.

High hydrogen concentration reduces the Btu value of the fuel gas. If the Btu content drops low enough, this can result in unstable furnace operation and can reduce unit production rates. At the steam boilers, this can result in a significant reduction in steam production and cause an upset in the steam system, which can upset unit operations.

The flare gas compressors are not significantly impacted by higher hydrogen levels, since they are positive displacement compressors. However, high hydrogen concentrations in the gas feeding the centrifugal wet gas compressors (flare gas is recovered and sent to these compressors) affects the performance of the wet gas compressors in that it will drive the compressor closer to its surge curve which can be potentially damaging to the machine.

High flows of nitrogen from equipment decommissioning can lead to a much higher than normal inert content in the mixed flare gas, greatly reducing its heat content (measured as Btu/scf). When this low Btu flare gas is transferred to the fuel gas header, the lower heat content can have the effect of reducing combustion efficiency, as the burners are designed to operate with fuels that have a higher heat content per cubic foot. In extreme cases, the heating value of the gas can be reduced by dilution with nitrogen to the point of extinguishing the burner flame. This creates the potential for unburned fuel to accumulate in the heater or boiler, leading to an explosion when it is re-ignited. NFPA 85 – Boiler and Combustion Systems Hazards Code and NFPA 86 Standards for Ovens and Furnaces warn against the use of practices that can lead to this possibility.

The higher than normal nitrogen content of flare gas that can result from nitrogen purging has the effect of greatly increasing its molecular weight. Reciprocating compressors increase the pressure of a constant inlet volumetric flow rate of gas. For a given volume of gas, an increase in molecular weight creates an increase in its mass. This increases the work that the compressor has to do to compress the gas, overloading and potentially damaging the machine.

A major advantage of using steam to clear hydrocarbons from equipment is its elevated temperature, however this can be a disadvantage with respect to flare gas recovery. When the distance the gas must travel to reach the flare gas compressor is large, the gas will cool, and much of the steam will condense and be removed as water at the knockout drum. However; with a shorter flare line or a long-duration steam out event, the temperature of the flare gas at the flare gas compressor can be elevated significantly. If the temperature of the flare gas stream at the inlet to the flare gas compressor exceeds machine limits, the gas must be diverted away from the compressor inlet in order to avoid mechanical damage. Another disadvantage of the use of steam is that most of what is added as a vapor will condense in the flare gas headers and be removed via the water boot of a knockout drum, either as the result of cooling as it flows through a long flare line or in a chiller/condenser included specifically for removal of water vapor from the flare gas. This creates a sour water stream requiring treatment.

Shutdown and Startup Process

During periods of startup and shutdown, a potential for flaring exists. This can be due to several reasons including an imbalance of material producers and users (e.g. fuel gas or hydrogen). Flaring can also occur due to specific startup or shutdown procedures that require venting to the flare system during some portion of the startup or shutdown process. Martinez makes every effort to eliminate flaring from startups and shutdowns. There are, however, situations where this goal is not achieved. Martinez is a highly complex refinery and has a high degree of unit integration. Therefore, the shutdown and start-up of a process unit often affects one or more units upstream or downstream, and in some cases the entire refinery.

As a processing unit is shut down, rate is typically reduced to minimum, and the operations of other affected units are adjusted accordingly in a controlled fashion. Typically, minimum rate is about one-half of a unit's design capacity, and is determined by equipment constraints. When the unit ultimately does shut down, meaning feed to the unit is reduced from minimum to zero, imbalances may occur at other units that are upstream or downstream, or in the refinery as a whole. Flaring can often be prevented, but in some cases the operations of the units that are affected cannot be adjusted quickly enough (due to mechanical and process limitations), and excess material must be flared to avoid over-pressuring equipment. During unit start-ups, similar situations can occur.

For example, when a catalytic reforming unit is started up, hydrogen is initially produced more quickly than can be consumed in the refinery, and the excess hydrogen must be flared until operations can be balanced. Similarly, when a catalytic reforming unit is shut down, some amount of excess hydrogen must be produced at other hydrogen-producing units in advance to compensate for the loss that is about to occur. Once the unit has been shut down, operations can be balanced, and flaring stops. In some situations, part of the excess hydrogen required in start-up and shutdown situations can be routed to the refinery fuel gas system up to the operating limits of that system.

At the Chemical Plant, start-up and shutdown procedures involve sending gas to the flare via the relief scrubber. This is done to ensure personnel safety prior to maintenance activities and to protect equipment prior to re-commissioning. On shutdown, equipment is purged with steam to the relief system to ensure a safe environment for personnel entry during maintenance and inspection tasks. On start-up, air is purged from the unit using steam or nitrogen. The difficulties associated with recovery of Chemical Plant flare gas is discussed in the Existing Systems for Vent Gas Recovery portion of Section 3.4.2.

Analysis of Prior 5 years of Major Maintenance Related Flaring

A review of the last 5 years of maintenance related flare events was conducted. Due to the time that has passed for many of those events, it was difficult to gather enough specific details of the situation (e.g. when purging started and stopped, vessels were opened, etc.) to develop specific findings. However, a review of the data confirms that vessel depressurization and purging, fuel gas system imbalances, and hydrogen system imbalances account for the majority of the flaring related to major maintenance activities. Provided below is an analysis of the major maintenance related flaring and the FMP planned prevention measure associated with each cause.

Historic Major Maintenance Flaring Analysis

Flaring events related to major maintenance were reviewed and the primary cause of the flaring for those events was grouped into 5 main categories. Those categories are: 1) hydrogen system imbalance, 2) flare compressor shutdowns, 3) fuel gas system imbalance, 4) shut down of the No. 5 Gas Plant, and 5) general flaring related to unit shutdowns. Each of these causes are discussed below, along with the method proposed in the FMP to address those situations.

Hydrogen System Imbalance

This cause contributed to about 1% of the major maintenance related flaring incidents between 2015 and 2020 which were reviewed.

Primary Cause of the Flaring

An imbalance in the hydrogen system can occur when the production of hydrogen is out of balance with hydrogen consumption at various units. This can occur during startup and shutdown situations at hydrogen producing or consumption units. Typically, when a hydrogen consumption unit is shutdown, the production of hydrogen can be reduced concurrently to ensure that the hydrogen system stays in balance. However, during a startup of a hydrogen producing unit, the hydrogen producing unit is brought on line and the hydrogen is sent initially to the flare header, so the hydrogen consumption units are not impacted by the startup. Those impacts can be related to low hydrogen purity during startup or the stability of unit operations due to varying hydrogen quantities. This results in several hours of flaring until the hydrogen product meets the quality specifications.

For example, Air Products operates a 35 MMSCFD Hydrogen Plant that is located inside the Martinez fenceline. Air Products normally produces utility hydrogen, which is sold exclusively to the Martinez. During start-up, feed is introduced into the unit and the unit begins producing a low purity hydrogen product. This product contains 75% hydrogen, 16% CO_2, 3% CO, 6% methane and other impurities. This low purity hydrogen product cannot be used in Martinez as it contains contaminants that could permanently poison catalyst in other refinery catalytic process units (e.g. No. 3 HDS, Hydrocracker, etc.). As a result, the hydrogen is directed to a flare until the product hydrogen purity of 99% is achieved.

After the initial step of introducing feed, the Pressure Swing Absorber (PSA) skid is then placed in service to increase hydrogen purity and remove contaminants. It takes approximately 4 to 6 hours to line out the filtration system. Once the hydrogen reaches an acceptable purity, Air Products personnel notify the Martinez 's shift organization and the hydrogen is gradually introduced into the 400 lb hydrogen header. These types of units produce both CO and CO_2 as by-products. Since both of these carbon oxides can inhibit hydrodesulfurization reactions, hydrogen produced at either No. 1 or No. 2 Hydrogen Plant is not suitable for use as make-up for hydrogen-consuming units until the level of CO plus CO_2 is less than 50 ppm. This specification is confirmed by an on-line analyzer at No. 2 Hydrogen Plant. At No. 1 Hydrogen Plant this specification is confirmed by laboratory analysis and can be inferred by methanator differential temperature.

In 2017 Air Products modified their startup procedures such that the Air Products startups do not normally exceed 500,000 SCF of flaring.

Hydrogen produced at catalytic reformers like No. 2 and No. 3 Reformers does not contain CO or CO_2, and can normally be routed to the refinery soon after the introduction of feed, provided it is free of inert gases like nitrogen that may have been used to purge equipment.

Minimum rate at No. 2 Hydrogen Plant is about 18 MMSCFD, so that is typically the amount of hydrogen that must be flared until the level of CO plus CO_2 is less than 50 ppm. At No. 1 Hydrogen Plant, minimum rate is approximately 35 MMSCFD, and once again, that is the amount of gas that must be flared until the hydrogen is on-spec.

During start-ups, the volume of off-spec hydrogen produced is too great to be handled by the refinery fuel gas system. Routing all of the off-spec hydrogen that is produced during start-up of either No. 1 or No. 2 Hydrogen Plant to the fuel gas system could potentially cause that system to become unstable and over pressure. Additionally some of the by-products produced during hydrogen plant start-ups, like CO and CO_2, are not suitable fuel gas components.

The number of hydrogen plant start-ups per year varies, but averages about two to three times per year. Efforts to reduce unplanned shutdowns to a minimum are ongoing. They include the maintenance and inspection programs mentioned in Section 3.4.3. In addition, attempts are in progress to extend the boiler inspection interval (state mandated) to reduce plant shutdowns. Further, the contract with Air Products includes provisions for on-stream efficiency.

No. 1 and No. 2 Hydrogen Plants are shut down to inspect equipment, service relief valves, change catalyst, and re-new boiler operating permits. Also, hydrogen plant shutdowns can occur due to unit upsets and/or equipment malfunction. In addition, the No. 1 Hydrogen Plant may also be shut down to balance the refinery hydrogen system if a major hydrogen consumer like the Hydrocracker were to be shut down.

Hydrogen Plant planned turnaround dates are driven by the need to inspect equipment, service relief valves, change catalyst, and re-new boiler operating permits, and cannot be extended beyond the required frequencies for these activities.

The Martinez refinery has not identified a way to introduce low quality hydrogen (i.e. high levels of CO and CO_2) into the hydrogen header due to the adverse impact on the catalyst in downstream units. Attempts are made to bring the No.1 and No. 2 Hydrogen Plants up to full quality as quickly as possible (by bringing the methanator at No.1 Hydrogen Plant and the PSA unit at No.2 Hydrogen Plant on quickly) to minimize flaring.

At Martinez, hydrogen is distributed from the hydrogen-producing units to the hydrogen-consuming units via a system of pipes that operates at about 400 psig. To avoid flaring, feed rates and other operating parameters at these hydrogen producing and consuming units are adjusted on a regular basis to maintain a balance. The start-up of a major hydrogen-producing unit like No. 1 Hydrogen Plant is typically planned and executed so that it coincides with the start-up of a hydrogen-consuming unit like the Hydrocracker. This practice reduces flaring by maintaining the balance between production and consumption. During unplanned situations, the startup and shutdown of hydrogen producing and consuming units may not coincide.

During the shutdown and start-up of the No. 1 Hydrogen Plant, a portion of the hydrogen produced is recycled back into the hydrogen plant to avoid flaring. The hydrogen plant shutdown procedure has been revised, and this new technique was used successfully when the unit was shut down recently.

Actions to Minimize or Eliminate Flaring during this Situation
The following actions have been identified to minimize flaring associated with the startup of hydrogen production units:

- Try to minimize the number of required plant start-ups each year, achieving a high plant on-stream efficiency and extending turnaround dates. This action is already in place.
- Coordinate the start-up of hydrogen production units to insure product is used, when available, to minimize flaring. This action is already in place.

FMP Planned Prevention Measure
The concept Martinez used to develop the FMP was to design a process to ensure that flare elimination or minimization was incorporated into work processes performed at the refinery (e.g. major maintenance activities, process unit turnarounds, etc.). This includes pre-turnaround planning, maintenance planning, and actions to eliminate or reduce the chance of malfunctions, upset, and situations associated with flare gas quality and quantity issues. This approach has been proven to eliminate or minimize flaring and will be utilized to identify and implement prevention measures. Martinez did not consider any other items not specifically noted in the FMP.

Flare Compressor Shutdowns
This cause contributed to about 1% of the major maintenance related flaring incidents that were reviewed between 2015 and 2020.

Primary Cause of the Flaring
The flare recycle compressors can shut down for various reasons. This can occur due to high oxygen content in the flare gas or for planned maintenance on the compressors. The flare compressors can also be purposely shut down when the flare gas quality is such that it could result in damage to the compressors or could cause gas quality problems in the fuel gas system. The compressors may also be shut down when there is more fuel gas available than there are fuel gas consumers, so recycling the flare gas to fuel gas system is not feasible.

If the oxygen content of the flare gas gets too high, the flare gas recovery compressors will automatically shut down to prevent the development of an explosive mixture in the system. Also, the flare recovery compressors and associated equipment may need to be shut down to perform maintenance. In addition, there are situations when the flare gas quality is such that the molecular weight of the flare gas could be low enough to damage compressors in the system that cannot handle lower molecular weight gases or the composition of the flare gas is such that it could impact the fuel gas quality and result in upsets at the furnaces burning the fuel gas. The fuel gas compressors could also be shut down if the fuel gas balance is such that there is excess fuel gas and recycling the flare gas would simply overpressure the fuel gas system and send the gas right back to the flare. This last situation is discussed further in a later portion of this section.

In each of these situations, the flare recycle compressors are no longer available to recover flare gas, and that gas is sent to the flares.

The oxygen in the flare gas primarily comes from the vapor recovery system which consists of atmospheric tanks and the marine vapor recovery system. Also, some minor amounts of oxygen can enter the system from the Merox Treating Unit. In the event of a high oxygen level in the flare gas, enrichment gas (propane) would typically be added to reduce the oxygen concentration. For example, if a tank PV valve is not operating properly, air can enter the system. If there is an unintended opening in the marine loading system (e.g. a vessel hatch, etc.), air can also enter the vapor recovery system. The refinery has not succeeded in preventing this from occurring at all times. Once the situation occurs, action can be taken, as noted above, to add enrichment gas.

The flare recovery compressors are positive displacement compressors and are not sensitive to molecular weight. Nonetheless, the flare flow meters include molecular weight on each flare header and an oxygen analyzer. Occasionally, both machines need to be shut down together when work is required on a part of the system that is common to both compressor trains such as the recovered gas knockout pot.

<u>Actions to Minimize or Eliminate Flaring during this Situation</u>
The following actions have been identified to minimize flaring associated with the shutdown of the flare recycle compressors:

- Continue to monitor compressors under rotating equipment, reliability, and inspection programs to reduce chance of an unplanned outage
- Schedule planned maintenance on one compressor at a time as much as possible
- Monitor flare vent gas oxygen levels and take action to try to keep oxygen levels low
- Maintain flare vent gas oxygen monitors to reduce the chance of monitor malfunctions that could shut down the flare gas recovery compressors

<u>FMP Planned Prevention Measure</u>
The concept Martinez used to develop the FMP was to design a process to ensure that flare elimination or minimization was incorporated into work processes performed at the refinery (e.g. major maintenance activities, process unit turnarounds, etc.). This includes pre-turnaround planning, maintenance planning, and actions to eliminate or reduce the chance of malfunctions, upset, and situations associated with flare gas quality and quantity issues. This approach has been proven to eliminate or minimize flaring and will

be utilized to identify and implement prevention measures. Martinez did not consider any other items not specifically noted in the FMP.

Fuel Gas System Imbalance

This cause contributed to about 0.1% of the major maintenance related flaring incidents that were reviewed between 2015 and 2020.

Primary Cause of the Flaring

An imbalance in the fuel gas system can occur when the production of fuel gas is out of balance with fuel gas consumption at various units. This can occur when significant fuel gas combustion equipment is shut down while major fuel gas producing units are still online. This can occur for short periods when equipment is being taken off line, until the fuel gas system can be brought back into balance. This can also occur for longer periods of time if, after reducing fuel gas producing units to minimum operation, there is still more fuel gas generated than consumption demand.

The Martinez refinery makes every effort to eliminate fuel gas imbalance situations. There are, however, situations when that goal is not achieved. An example of this would be if a maintenance turnaround is required to meet a regulatory compliance deadline that would not fit into a normally scheduled maintenance turnaround schedule.

In addition, there are situations when the balance of fuel gas production and consumption for a specific set of operating units cannot be attained by manipulating the rate/severity of those units within their maximum and minimum rates. For example, when the No. 5 Gas Plant is down and the FCC is in operation, the No. 4 Gas plant cannot handle all the wet gas produced by other units, even with the FCC at minimum rate and severity.

Also, increasing fuel gas consumption when doing so would negatively impact the balance between unit products and feeds (when more is produced by one unit than can be fed to the downstream unit, or stored) is unlikely to reduce flaring. Additionally, increasing fuel gas consumption can negatively impact regulatory requirements such as the Regulation 9, Rule 10 NOx cap or other limits.

Actions to Minimize or Eliminate Flaring during this Situation

The following actions have been identified to minimize flaring associated with fuel gas system imbalance situations:

- Coordinate major equipment maintenance shutdowns, to the extent feasible, to minimize or eliminate fuel gas imbalance situations
- Should fuel gas imbalance situations still occur, try to reduce fuel gas production to minimize or eliminate the fuel gas imbalance situation
- Should fuel gas imbalance situations still occur, try to increase fuel gas usage to minimize or eliminate the fuel gas imbalance situation

FMP Planned Prevention Measure

The concept Martinez used to develop the FMP was to design a process to ensure that flare elimination or minimization was incorporated into work processes performed at the refinery (e.g. major maintenance activities, process unit turnarounds, etc.). This includes pre-turnaround planning, maintenance planning, and actions to eliminate or reduce the chance of malfunctions, upset, and situations associated with flare gas quality and quantity issues. This approach has been proven to eliminate or minimize flaring and will be utilized to identify and implement prevention measures. Martinez did not consider any other items not specifically noted in the FMP.

No. 5 Gas Plant Shutdown
This cause contributed to about 1% of the major maintenance related flaring incidents that were reviewed between 2015 and 2020.

Primary Cause of the Flaring
The flare gas recovery compressors return the recovered flare gas to the No. 5 Gas Plant, where it is compressed further, treated, and sent to the fuel gas system (see Attachment 4 for a diagram of the flare gas recovery system). When the No. 5 Gas Plant is shut down for scheduled maintenance, there is no way to recover the flare gas.

When No. 5 Gas Plant is shutting down for a turnaround, the FCC is brought to minimum rate in order to make room in No. 4 Gas Plant for the extraneous gas streams that normally go to No. 5 Gas Plant. During this time the rates to refinery units are reduced, No. 4 Gas Plant capacity is at its maximum and is not able to run all the gas produced.

The following actions have been taken to reduce No. 5 Gas Plant turnaround duration: 1) scope reviews are held prior to each turnaround, which include efforts to minimize turnaround duration, and 2) detailed planning and scheduling of each turnaround is conducted to minimize turnaround duration.

Although these actions are routinely taken, it may not be possible to reduce the duration of the turnaround due to the work scope which needs to be completed to address mechanical integrity, performance, or regulatory requirements.

Actions to Minimize or Eliminate Flaring during this Situation
The following actions have been identified to minimize flaring associated with the shutdown of the No. 5 Gas Plant:

- Prior to a No. 5 Gas Plant shutdown, as a part of the turnaround pre-planning process, determine if there are feasible actions to reduce the amount of flare gas being generated
- As a part of the turnaround pre-planning process, determine if there are feasible actions to reduce the length of the No. 5 Gas Plant turnaround
- Consider the feasibility of other routing options for flare recycle gas during No. 5 Gas Plant shutdowns

FMP Planned Prevention Measure
The concept Martinez used to develop the FMP was to design a process to ensure that flare elimination or minimization was incorporated into work processes performed at the refinery (e.g. major maintenance activities, process unit turnarounds, etc.). This includes

pre-turnaround planning, maintenance planning, and actions to eliminate or reduce the chance of malfunctions, upset, and situations associated with flare gas quality and quantity issues. This approach has been proven to eliminate or minimize flaring and will be utilized to identify and implement prevention measures. Martinez did not consider any other items not specifically noted in the FMP.

General Flaring Related to Unit Shutdowns

This cause contributed to about 96% of the major maintenance related flaring incidents that were reviewed between 2015 and 2020. This period included a refinery-wide strike between February and April 2015, and the ongoing refinery idling event which started in April, 2020

Primary Cause of the Flaring

During major maintenance, various activities can result in flaring. This can be due to increased flow of vent gas to the flare gas system that exceeds the system's ability to recover the flare gas. This can also be caused by a change in the quality of the flare gas (such as high nitrogen content) that results in the flare gas being unsuitable for recovery as fuel gas. These situations can result from the depressurization of vessels, purging of vessels to the flare system, and during periods of equipment start up and shut down when gas is being sent to the flare system.

Unit, system, and vessel depressurization and purging operations are controlled to minimize flaring by regulating the rate at which depressurization occurs. This is accomplished by throttling the valves that are used to control depressurization rates. Flow meters at the flares are monitored to verify that depressurization rates are not excessive. Multiple depressurizations are typically staggered to reduce the possibility of flaring and are coordinated by the Shift Superintendent. Flaring is reduced by monitoring the rate at which equipment is depressured to the flare and adjusting the depressurization rate as needed to try to stay within the flare gas recovery system capacity.

In general, the refinery stays within the ability of the flare gas recovery system when shutting down and purging refinery units. However, situations can arise where the capacity of all the compressors is exceeded. For example, the flow rate of nitrogen needed to properly clear a reactor vessel (and catalyst) of hydrocarbon can exceed the ability of the flare gas recovery system to recover the gas. In those cases which involve large amounts of process units being shutdown or idled, as was the case with the 2015 USW strike and the 2020 refinery idling event, process combustion sources which normally receive recovered flare gas are no longer available. Flaring events will commence once the rate at which gas is routed to the main flare system exceeds the rate at which it can be combusted by these sources.

Actions to Minimize or Eliminate Flaring during this Situation

The following actions have been identified to minimize flaring associated with general shutdown related flaring:

- Control vessel depressurization and purging vent gas sent to try to stay within the recovery ability of the flare system.
- For events which necessitate the shutdown or idling of the refinery or large numbers of process units, stage the shutdown of individual combustion sources to maximize flare gas recovery, finishing with the shutdown of the No. 5 Gas Plant.

<u>FMP Planned Prevention Measure</u>

The concept Martinez used to develop the FMP was to design a process to ensure that flare elimination or minimization was incorporated into work processes performed at the refinery (e.g. major maintenance activities, process unit turnarounds, etc.). This includes pre-turnaround planning, maintenance planning, and actions to eliminate or reduce the chance of malfunctions, upset, and situations associated with flare gas quality and quantity issues. This approach has been proven to eliminate or minimize flaring and will be utilized to identify and implement prevention measures. Martinez did not consider any other items not specifically noted in the FMP.

<u>Summary</u>

The Martinez refinery has performed each of the listed major maintenance activity types without flaring. As a result of this examination, it was determined that, for each major maintenance activity, the pre-turnaround planning process will be used to minimize or eliminate flaring on a case-by-case basis, including reducing process flow rates (see more detailed description in Description of Planned Prevention Measures section below). Considering that each turnaround is unique (i.e. what units will be shut down, the order of the shutdown, the extent of the shutdown and maintenance or other actions that need to be performed, etc.), Martinez believes that this will provide the best opportunity to eliminate or reduce flaring. This process has been used in recent turnarounds and has yielded good results in reducing or eliminating flaring.

Additionally, Martinez looked at the feasibility of providing additional compression, storage and treatment options to minimize flaring due to issues of gas quantity and quality. These options were determined to be infeasible based on cost (see section 3.4.2).

Description of Planned Prevention Measures

As a part of the planning process for maintenance activities, Martinez includes the consideration of what actions could be taken to eliminate or reduce flaring resulting from those activities. The method used to consider flare minimization actions varies depending upon the nature of the maintenance.

Planned maintenance turnarounds are typically scheduled and planned many months to years in advance. For planned maintenance turnarounds, appropriate Operations and Maintenance personnel will conduct a pre-turnaround evaluation of potential flaring that may occur as a result of the specific turnaround being planned and consider actions that could be taken to either eliminate flaring or minimize flaring from those activities. At a minimum, the bulleted measures identified below are considered during the pre-turnaround planning process, including rate reductions.

Consistent with this FMP, potential prevention measures to eliminate or minimize flaring will be considered in light of the technical, safety, regulatory, and cost impacts associated with the measure. Measures will be implemented, consistent with good safety and environmental practices, and which can be performed in a cost effective manner.

This process has been used in recent turnarounds and has yielded good results in reducing or eliminating flaring. This process is documented in a procedure which is followed for planned major maintenance activities.

This procedure includes a post-turnaround evaluation. When the turnaround is complete, Martinez evaluates which flare elimination and minimization actions were effective and which were ineffective. Since the majority of flare minimization results from planning unit shut down sequences and vessel depressurization timing, the refinery can review the shutdown timeline of events vs. flaring activity to determine if that particular plan of activities produced less flaring. From that evaluation, a set of recommendations are developed for consideration for the next turnaround planning effort for that equipment.

These planning sequence documents are available at Martinez for District review. This allows the District to verify that the planning process was followed and to ensure that appropriate actions were taken to eliminated or minimize flaring.

For routine maintenance activities, Martinez considers how to avoid or minimize flaring as part of our work practice.

All events of significance as noted in Regulation 12, Rule 12 (i.e. all reportable flare events) are evaluated to determine whether flaring could be eliminated or reduced from such events. Conducting causal analyses for extremely small flaring events is difficult and emissions from such small events are so low that it is not reasonable or cost effective to conduct a causal analysis. Very small flare events are, by their very nature, either very low flow events and/or very short in duration. In general, it is not possible to determine the cause of such events due to their brief, low flow nature.

Occasionally, maintenance must be performed with very short notice. This is usually due to concern regarding potentially imminent equipment failure or to address a safety concern. Due to the short time allowed to conduct the maintenance, there is not typically time to conduct an analysis of potential flaring impacts. For such unplanned maintenance, if a reportable flare event occurs as a result of the maintenance work, a causal analysis would be conducted and would consider what action should be taken to prevent or minimize flaring in the future from that maintenance activity.

Measures to Minimize Flaring During Preplanned Maintenance
Examples of measures that would be considered to eliminate or minimize flare emissions are provided below:

- Depressuring to other closed systems first to minimize material sent to the flare system
- Depressuring to the flare system slowly to help stay within the flare recovery system capacity
- Modify unit operations at fuel gas generating units to reduce gas make and keep the fuel gas system in balance (such as changing unit rates and reducing FCCU temperature)
- Increase firing at furnaces to increase gas consumption and keep the fuel gas system in balance
- Use of chemicals to improve initial hydrocarbon removal to reduce the time needed for steam out or purging to flare
- Route gas streams with significant hydrogen content to the Hydrogen plant for hydrogen recovery instead of being routed to the flare.
- Shutdown activities are staged to keep the rate to the flare gas system within the recovery capability
- Maintain good communication and coordination within the Operations shift organization so that the flare gas compressor load is not exceeded.
- Feed and product compressors are used to recycle material during startup until product specifications are met, allowing flaring to be avoided.

The measure to route the depressurized or purged gas slowly to the flare gas recovery is a general practice, but has not been incorporated into all shutdown procedures. As the shutdown procedures are revised, this will be incorporated into those procedures.

Operations of units that produce fuel gas range materials are adjusted, including at times reducing severity of operations in the process unit (e.g. FCC), to reduce fuel gas production if it would put the refinery in a flaring situation. Specifically, actions are taken to reduce FCCU unit rate and/or operating severity (i.e. reduce the reactor temperature) to reduce overall refinery gas production.

There are three feed/product compressors. Each compressor has a capacity on the feed side of approximately 8 MMSCFD and on the product side of about 30 MMSCFD. The use of feed and product compressors to recycle material during startup or shutdowns until product specifications are met is specific to the No. 1 Hydrogen Plant and is considered as a part of the pre-planning process as noted in Section 3.4.1. To the extent that this appears to be a method that can be used in essentially all startups or shutdowns, it will be incorporated into the procedures. This has already been incorporated into the Hydrogen Plant shutdown procedures. If there is still uncertainty on whether this can be done routinely (i.e. whether this can be done is dependent on the specific planned major maintenance situation), then the procedures would not be modified, but the method will continue to be considered during the pre-planning for the planned major maintenance.

In general, these measures will be performed provided the equipment required to perform them is available. It is, of course, impossible to identify all situations that preclude the use of one or more of these actions. However, an example of such a situation would be the use of chemicals to improve initial hydrocarbon removal in reactor vessels that contain catalyst, since the chemical would damage the catalyst. Another example would be that all equipment may not have connections to the wet gas system which would make it impossible to route gases to other closed systems before sending it to the flare.

All these measures reduce flaring by sending gases that might normally be routed to flare to other locations where they can be recycled or processed.

50 Unit Flare
The 50 Unit flare was designed so that there would be no flaring during normal startups and shutdowns. The 50 Unit flare gas recovery system compressor is sized for complete recovery of the vapors during normal operations, and during de-pressuring and steam-out of smaller equipment for maintenance. The existing spare 50 Unit wet gas compressor is lined up and used for recovery of the vapors during de-pressuring and equipment steam-out of larger process equipment. The existing spare wet gas compressor will also serve as a common spare between the flare gas recovery service and the wet gas service. Instrumentation and controls have been provided to enable switching of an existing spare wet gas compressor from wet gas service to the vapor recovery service, after proper line-up. Since equipment de-pressuring and steam-out operations are well planned operations, sufficient time is available for changing over from the small flare gas recovery system compressor to the existing wet gas compressor and vice versa. Control valves have been provided on the steam-out lines from large process equipment for controlling steam-out rates to minimize the chance that the 50 Unit Flare liquid seal would be broken during the steam-out operations. A pressure control valve upstream in the compressor suction line will maintain a constant pressure in the flare gas recovery system, by discharging all vapors from normal venting (purges), equipment de-pressuring and steam-out for maintenance, into the refinery fuel gas system, through the wet gas compressor and the wet gas header.

3.4.2 Gas Quality and Quantity

This section discusses when flaring is likely to occur, systems for recovery of vent gas, and options for recovery, treatment and use of flare gas.

Releases of vent gas to the flare can result from an imbalance between the quantity of vent gas produced by the refinery and the rate at which it can be compressed, treated to remove contaminants (sulfur compounds) and utilized as fuel gas. In addition, releases of vent gas to the flare can result from a change in vent gas composition that either makes it infeasible to compress or infeasible to burn as fuel gas.

Situations that can lead to flaring can be grouped together based on similarity of cause. These general categories, including specific examples of events which fit into each category, are outlined and discussed below.

Maintenance Activities Including Startup and Shutdown
Generally, in order to maintain either an individual equipment item or a block of refinery equipment, it is necessary to remove it from operation and clear it of process fluids. Examples include:

- Unit shutdown

- Working on equipment
- Catalyst change
- Leak repairs
- Compressor repairs
- Unit Startup

Each of these activities impact refinery operations in a variety of ways. In order to minimize the risk of flaring, there must, at all times, be a balance between producers and consumers of fuel gas. When either a block of equipment or an individual equipment item is removed from service, if it either produces or consumes gases, then the balance of the fuel gas system is changed and adjustments are necessary to bring the system back into balance. If the net change in gas production/consumption is large and adjustments in the rate at which gas is produced or consumed by other units cannot be made quickly enough, then flaring results.

Additionally, in order to clear hydrocarbons from equipment in a safe and orderly fashion so as to allow it to be maintained, a variety of procedures must be used. Many of these necessary procedures result in changes in the quantity and quality of fuel gas produced. This has been discussed in Section 3.4.1.

Malfunctions and Upsets

An imbalance in the flare gas system can also result from any of a series of upsets or equipment malfunctions that either increase the volume of flare gas produced or decrease the ability of the fuel gas handling system to accommodate it. Examples include:

- Relief valve releases, leaks, or malfunctions
- Loss of a major piece of equipment (pump, compressor, etc.)
- Loss of fuel gas or flare gas recycle compressors
- Loss of a utility (steam, cooling water, power)
- Loss of air fin fans or condensers

These examples can be caused by equipment malfunction, outside entities, operator error, or various other causes. Each of these bullet items can result in flaring, to the extent that the amount of gas exceeds the flare gas recovery system capacity or the composition of gas precludes its use as fuel gas. For example, if a relief valve relieves to the flare, the flow can be greater than the capacity of the flare gas recovery system, resulting in flaring. The loss of a major piece of equipment can result in a unit shutdown which can send high volumes of gas to the flare system or send high concentrations of hydrogen to the flare system, resulting in flaring. If the flare recycle compressors trip, the gas cannot be recovered and would result in flaring. Losses of electricity or other utilities, as well as losses of other equipment can result in unit upsets that require vent gas to be sent to the flare as a safety measure, which will again result in flaring.

Emergencies

Various situations can result in events that require immediate corrective action to restore normal and safe operation. Emergency flaring events are defined by Regulation 12-12-201.

High Base/Continuous Load
Although flaring is often the result of a sudden, short-term imbalance in the flare/fuel gas system, it is made more likely when the gap between the capacity of the flare gas recovery system and long term average flow to the flare header is reduced. This can be caused by high normal flows of vent gas to the flare or by limited flare gas recovery capacity. High normal flows refers to situations where the routine flow of gas to the flare system is higher than usual. This would reduce the amount of additional gas that could be sent to the flare system before the flare gas recovery compressor capacity would be reached, resulting in flaring.

Reduced Consumption of Fuel Gas
If flaring is to be minimized, it is necessary to balance fuel gas producers and consumers in the refinery. Situations that reduce fuel gas use can limit the amount of vent gas that can be recycled. Reduced fuel gas use can result from energy efficiency projects that reduce fuel gas consumption or equipment temporarily shutdown. As the energy efficiency of furnaces or boilers is increased, less fuel is used (i.e. less gas is burned for the same operating rate. As the fuel use is reduced, more fuel is available in the fuel gas system. The types of energy conservation projects that can reduce fuel gas use include efforts to minimize oxygen levels in furnaces and boilers, and efforts to optimize distillation tower reflux.

Other Causes
There can be other occasional situations that result in flare vent gas composition or quantity impacts that can be potential causes of flaring. These tend to be infrequent and can be exceedingly difficult to totally eliminate, despite careful planning and system design.

Vent Gas Recovery Systems
Refinery unit operations both produce and consume light hydrocarbons. Most of these hydrocarbons are routed directly from one refinery process unit to another. Refineries are constructed with a network of flare headers running throughout each of the process units in order to allow collection and safe handling of any hydrocarbon vapors that cannot be routed directly to another process unit. The hydrocarbon vapors are collected at low pressures in these flare headers. These gases are recovered for reuse by increasing their pressure using a flare gas recovery compressor system. The compressed gases are returned to the refinery fuel gas system for use in fired equipment within the refinery. Any gas not compressed and sent to the fuel gas system is routed to a flare so it can be disposed of safely by combustion under controlled conditions.

The capacity of a flare gas recovery system is generally taken as the total installed nameplate capacity of the flare gas compressor. However, flare gas compressor capacity does not fully define the practical total capacity of the system. The ability of the flare gas recovery system to recover the gas and use it as fuel gas is practically limited by three things: 1) the flare recovery gas compressor capacity, 2) the fuel gas treating capacity, and 3) the ability to consume the additional fuel gas. The most constraining of these three items at any point will dictate the practical flare gas recovery system capacity.

Existing Systems for Vent Gas Recovery

The main refinery flare system has a flare gas recovery system that recovers and compresses the flare gas, sending it to the No. 5 Gas Plant where it is further compressed, sent through an amine treater and then sent to the fuel gas system. A diagram of the Martinez flare gas recovery system for the main flare system is provided in Attachment 8.

The ARU Flare does not have a vent gas recovery system. The reuse of ARU Flare gas is not possible due to the variation and hazardous nature of the material sent to the flare. The material that can be sent to the ARU Flare includes steam, nitrogen, ammonia, H_2S, and air. Due to this wide variation in material, there is no reasonable location that this material could be sent for recovery. For example, sending air, ammonia, or high amounts of H_2S into a fuel gas system would not be appropriate and could result in safety and/or operational issues (such as furnace upsets). In addition, due to the potential for high H_2S and/or ammonia levels in the flare gas, the potential for personnel exposure would be increased by redirecting these streams. The potential for leaks using rotating equipment would also pose a potential safety issue.

Gases from the relief header are fed to the relief scrubber where they are contacted with a continuously circulating stream of ammonia solution. This solution absorbs H_2S and ammonia with the resulting overhead vapor flowing to the flare. Circulation of the ammonia solution is maintained by a scrubber pump on a continual basis. Should a large relief load be present, a second larger circulation pump is started which increases scrubbing capacity by 2.7 times. The rich circulating solution is purged from the scrubber and sent to the feed mixing drum for reprocessing through the ARU. The scrubber itself is designed with two compartments. The first is used during normal operating conditions whereas the second is used during upset conditions when extra H_2S and ammonia absorbing capacity is required. Absorption capacity is limited by the size of the compartments, volume of the circulating ammonia solution, sizing of the existing pumps, storage capacity for the purged rich solution and hydraulic capacity (i.e. residence time) of the gases in the scrubber.

Therefore, the discussion below will focus on the feasibility of additional vent gas recovery for the main refinery flare system only.

Existing Martinez **vent gas recovery, storage, & scrubbing capacities (Main Flare & ARU Flare)**

A summary of the existing vent gas recovery, storage, and scrubbing capacity is provided in the table below:

Flare System	Flare Gas Compressor Capacity (MMSCFD)	Storage Capacity (MMSCF)	Scrubbing Capacity for Vent Gas (MMSCFD)	Total Gas Scrubbing Capacity (MMSCFD)
Main Flare System	4	0	4	60
ARU Flare *	0	0	2.3	2.3

*The Ammonia Plant Flare is dedicated to the Ammonia Plant/Sulfur Plant/Sulfuric Acid Plant. Due to the nature of the vent gases, there is no vent gas recovery equipment for this flare. However, there is a vent gas scrubber associated with this flare. The scrubber capacity of 2.3 MMSCFD is based on recovery of pure H_2S and can only be achieved for a short period of time.

The Martinez vent gas recovery system does not include any dedicated capacity for storage of fuel gas or vent gas. However, on a continuous basis Martinez optimizes the refinery fuel gas system of producers and consumers to maximize the capacity available for treatment and reuse of recovered gases by employing the following strategies:

- Adjusting the sources of fuel that are made up to the fuel gas system including imported natural gas, propane, and butane (or other refinery fuel sources). For example, the amount of purchased natural gas is adjusted to maintain the target fuel gas pressure. In addition, propane and butane are added, as needed, to increase the Btu content of the fuel gas. If there is a fuel gas system imbalance situation and the Btu content is acceptable, this material would not be added to the fuel gas system. These adjustments are made whenever the fuel gas system approaches getting out of balance. However, these efforts are not always successful, depending upon the operating situation at the time and there is no way to ensure Martinez is always in fuel gas balance;

- Adjusting the operations of units that produce fuel gas range materials including at times reducing severity of operations in the process unit (e.g. FCC) to reduce fuel gas production if it would put the refinery in a flaring situation;

- Adjusting the refinery profile for consumption of fuel gas by maximizing export of fuel gas to the third party cogeneration unit (within their operating constraints), maximizing steam production from refinery steam boilers, shifting rotating equipment to turbine drivers where feasible (which operate with steam generated in the fuel gas fired boilers), and at times reducing the throughput of processing units to minimize gas production. Fuel gas consumption is not maximized at all times because using more fuel gas than is absolutely necessary results in higher emissions and energy inefficiency. Rotating equipment can utilize steam or electricity to turn the equipment. In various locations throughout the refinery there are rotating equipment with a primary and spare and where the primary and spares are on different motive force (i.e. one using electricity and one using steam). In those locations, if the electric driver is in use, the spare equipment can be put on-line using steam, which will increase the steam use in the refinery. That, in turn, will result in an increase in firing at the refinery boilers, resulting in additional fuel use. If more fuel gas is being produced than consumed, this can help balance the fuel gas system, albeit in a limited fashion. Any additional firing at the boilers will reduce the amount of excess fuel gas being sent to the flare, in an excess fuel gas situation, resulting in reduced flaring

The total gas scrubbing capacity that is indicated is an integral part of the refinery fuel gas management system. This capacity is closely matched with the fuel gas consumers' (heaters, boilers, etc.) usage requirements. The capacity indicated as being available for recovered vent gas scrubbing will vary depending on the balance between fuel gas production and consumption; it will vary both on a seasonal basis and during the course of the day. For this reason a range is provided indicating the approximate minimum and maximum available capacity.

Options for Recovery, Treatment and Use

To address the requirements of Regulation 12-12-401.4, Martinez has considered the feasibility of further reducing flaring through additional recovery, treatment, and/or storage of flare header gases, or to use the recovered gases through other means. This evaluation considers the impact these additional systems would have on the volume of flared gases remaining in excess of what has already been recovered (as noted in the previous section), and the associated mass flow of hydrocarbons emitted after combustion in the flare control device.

The flare header is connected to both a flare gas recovery system and to several flares. Normally all vapor flow to the flare header is recovered by a flare gas recovery compressor, which increases the pressure of the flare gas allowing it to be routed to a gas plant where it is further compressed and treated to remove contaminants such as sulfur. The treated gas is then sent to the refinery fuel gas system. Gas in excess of what can be handled by the flare gas recovery compressors, the gas plant, the gas treating system, and/or the fuel gas system end users flows to a refinery flare so it can be safely disposed of by combustion. Therefore, in order to reduce the volume of gas flared, the following essential infrastructure elements must be considered whether:

- additional compressor capacity (at the flare area or at the gas plant) would be needed to increase vent gas recovery,
- additional capacity in treating systems would be needed to increase vent gas recovery, and
- there are sufficient end users for an increase in recovered and treated gas

In addition, providing sufficient storage volume to dampen out the variation in volumetric flow rate to the flare gas header could potentially reduce the volume of gas flared.

<u>Compressor Capacity</u>

Compressors are used to increase the pressure of the vent gas from near atmospheric pressure to the pressure of the wet gas system. The flare gas recovery compressors located in the flare area compress the vent gas to a pressure that allows the gas to be sent to the No. 5 Gas Plant. The No. 5 Gas Plant wet gas compressors increase the pressure further to send the gas to an amine treater and then to the fuel gas system. In order to recover additional vent gas it is necessary to have sufficient capacity in both the existing flare gas recovery compressor capacity and the wet gas compressors at the No.5 Gas Plant to match the desired vent gas recovery flow.

<u>Treating System</u>

Flare gas treating is used to condition flare gas for use as fuel in the refinery fuel gas system. Treatment is focused on removal of sulfur compounds (see also the discussion of fuel gas quality in Attachment 1). A range of technology options exist, most of which are based on absorption of acid gases into a "lean" amine solution (MEA, DEA, MDEA, DGA) with regeneration of the resulting "rich" solution by stripping at lower pressure. In order to recover additional fuel gas it is necessary to have sufficient capacity to match the capacity of gas treating systems to the peak flow rate of the flare gas requiring treatment. Even if the capacity for treating is large, managing a large increase in flare gas needing treatment is problematic. It is difficult, if not impossible, to increase treating flows as quickly as flare flows can increase.

This is because the capacity of gas treating systems must match the peak flow rate of the flare gas requiring treatment. The peak flare gas flow can exceed a rate of 50 MMSCFD and this rate can be achieved in a matter of 10 minutes or less. Such treating systems are designed for a specific flow rate (i.e. a design velocity of vapor traffic through the treater). Such systems also have a minimum turn-down rate (i.e. the rate at which the system will still function reasonably to treat the gas). Those turndowns are typically only about 25% or so. Therefore, such a treater would not effectively treat flows below about 37 MMSCFD. If the treater is sized smaller, it would not be able to handle the peak flow and could result in a loss of the liquid in the treater due to excessive vapor velocities.

End Use Capacity

End use capacity can be the limiting factor on the amount of flare gas that can effectively be recovered. Many refineries operate relatively near fuel balance (i.e. the amount of fuel gas generated is close to the amount of fuel needed for the various processes). There is typically a small amount of natural gas added to the fuel gas system to maintain pressure control. During period of significant flaring, the ability to practically recover and reuse the flare gas is often limited by end use capacity. There is typically not enough additional combustion capacity to consume a large increase in available gas. In addition, many of these situations are due to a significant upset or emergency situation which also makes accommodating the additional fuel gas difficult.

Storage

Options for storage of flare gas are analogous to those for storage of other process gases. Gases can be stored at low pressure in expandable gas-holders with either liquid (water) or dry (fabric diaphragm) seals. The volumes of these systems expand and contract as gas is added or removed from the container. Very large vessels, containing up to 10,000,000 cubic feet of gas can be constructed by using multiple "lifts", or stages. Gases can also be stored at higher pressures, and correspondingly lower volumes, in steel bullets or spheres. The optimal pressure vessel configuration depends on system design pressure and total required storage volume.

For any type of gas storage facility, both the selection of an acceptable site and obtaining the permits necessary for construction present difficulties. Despite the refinery's demonstrated commitment and strong track record with respect to safe handling of hazardous materials, the surrounding community is expected to have concerns about any plan to store large volumes of flammable gas containing H_2S and other sulfur compounds. Safety concerns are expected to impact site selection as well, with a relatively remote location preferred. Modifications to the recovery, storage and treating of refinery flare gases are subject to the provisions and approval of federal and local regulations including Process Safety Management (PSM), Contra Costa County Industrial Safety Ordinance (ISO), and California Accidental Release Prevention Program (CalARP). Although the objective of the project would be a reduction in flaring, there are expected to be multiple hurdles along the path to a construction/land use permit.

Evaluation

A consultant, ENSR, was used to conduct the evaluation and this information was reviewed by Martinez. In order to assess the feasibility of additional flare gas recovery, a hypothetical design for an upgraded system was developed. The impact that this system would be expected to have on hydrocarbon emissions, based on the refinery's recent flaring history, was then evaluated. Results of this evaluation are provided for three system capacities corresponding to: 1) the rate of flow of additional flared gases that could be recovered, 2) the modifications required to achieve that recovery, and 3) the estimated total installed cost for the additional equipment needed for the increase in recovery. The budgetary level (order of magnitude) cost information provided in this section has been developed based on total installed cost data from similar installations where available, otherwise vendor quotes in combination with standard industry cost estimation procedures have been used to estimate system cost.

The evaluation is based on the need for installation of three new major systems in order to increase recovery of flare gases from current levels:

- Additional flare gas recovery compressor capacity - the estimated cost to provide additional compressor capacity to recover vent gas flowing in the flare header in excess of current compressor capacity, for transfer to storage and / or treatment. Costs provided are for one un-spared compressor system to be added to the flare gas recovery system. The estimate is for a reciprocating compressor with all necessary appurtenances for operation, that is, knockout pots, coolers, and instrumentation for a fully functional system.

- Addition of surge volume storage capacity – the estimated cost to provide temporary surge storage for a portion of the gases routed to the flare header in excess of the volumes currently being recovered, treated, and consumed. The addition of temporary surge storage volume is necessary for any further increase in flare gas recovery to allow flare gas flow (which is highly variable) to be matched to the demand for fuel gas. The cost used is based on a storage volume equal to the total volume of gas accumulated over one day at the identified flow rate, and is based on recovery in a high pressure sphere system with discharge at a controlled rate back to the flare gas header. Other lower pressure approaches were considered (low pressure gas holder, medium pressure sphere), but for the sizes analyzed a high pressure sphere was identified as the preferred approach based on operational, safety and economic considerations. For the large storage volumes needed for some of the options considered, the cost is based on the use of multiple spheres.

- Additional recovered gas treatment capacity – the cost of additional amine-based treating capacity to process recovered gases for sulfur removal so that they can be burned by existing fuel gas consumers without exceeding environmental or equipment operational limits. Installed cost data for new treatment systems was scaled to estimate the cost of adding treatment for each of the two flow rates identified below. The assumption is that for small increases in treating capacity the existing treater(s) will be modified / upgraded to allow for the increase. No additional cost has been included for expansion of sulfur recovery system capacity.

The table below presents a summary of estimated total installed capital costs for various treatment capacities and scenarios.

Treatment Capacity (MMSCFD)	Additional Vent Gas Compressor Capacity	Surge Storage (24 hrs. at flow rate)	Providing Incremental Additional Gas Treating for This Flow	If Additional Compressor, Storage and Treating Capacity Added
2.0	$3,600,000	$5,000,000	$2,000,000	$10,600,000
4.0	$6,700,000	$10,300,000	$3,500,000	$20,500,000
100.0	$160,800,000	$250,800,000	$6,000,000	$417,600,000

In addition to estimating the type and cost of equipment that would be needed to recover additional flare gas, an evaluation was conducted of how much flare gas could practically be recovered using such systems along with an analysis of the anticipated emission reductions for each case. The key points of the evaluation are summarized below:

- The 2005 flaring data has been reviewed and, based on the monthly flare report data, the non-methane emissions per standard cubic foot (scf) of flared gas is 0.00019 lb of non-methane hydrocarbon per scf. This is based on sampling data from reportable flaring events, the flare gas flow data, and applying a 98% combustion efficiency for hydrocarbon.

- Daily average flaring data has been reviewed for the previous calendar year (2005) leading to the conclusion that, on an annual basis, the addition of 2 MMSCFD of additional (unspared) compressor system (including storage and treating) capacity would capture approximately 118 MMSCF of gases currently flared. This evaluation has been performed by totaling the volume of gas currently routed to the flare that could be captured by a system with a flow capacity of 2 MMSCFD. Flow in excess of the 2 MMSCFD rated compressor capacity cannot be recovered by this system. Short duration events have instantaneous flowrates higher than the daily average, so the use of daily data overestimates the volume that the system can capture.

- A similar evaluation has been performed to determine the impact of adding 4 MMSCFD additional flare gas compressor system capacity. This would result in the capture of an additional 49 MMSCF of flared gases on an annual basis.

- Applying the average gas composition and the pounds of non-methane hydrocarbons emitted per scf of flared gas factor to the identified reduction in flared gas volumes, the estimated reduction in non-methane hydrocarbon emissions that could be achieved was estimated at 11.0 tons/year for 2 MMSCFD additional flare gas compressor capacity and 15.6 ton/year for 4 MMSCFD additional flare gas compressor capacity.

- A factor that severely limits the reduction in emissions such a recovery system would achieve in practice is the capability of the fuel gas consumers to accept these gases at the time at which they are generated (from both a volume and quality perspective). The gas storage system which has been specified for each option is necessary if the improvements in flare gas recovery shown have any chance to be realized. However, the composition of the gas could preclude its use as fuel gas and, therefore, the amount of recovered gas is likely overestimated by this analysis. In addition, the 2005 flare data indicates many days where flaring occurred on subsequent days. This would likely prevent the use of much of the recovered gas since it would have to be processed and used by the end of the day to allow accumulation of flare gas on the following day. This is unlikely and would also result in an overestimation of the flare gas actually recovered.

- In order to capture the gas associated with the type of longer duration flaring event that accounts for most emissions from the flare(s) on an annual average basis, a very large capacity for flare gas compression and storage is needed. The third case Martinez has presented, for a system with a capacity of 100 MMSCFD, reflects what would be needed to capture and control all vent gases for this type of event. The system as proposed makes use of 24 flare gas compression systems at 4 MMSCFD each feeding 97 storage spheres, each of which are 60 foot in diameter. The increase in treater capacity is limited to 8 MMSCFD, as flare gas would be stored prior to treatment and worked off through the treater at a gradual rate in line with the ability of the fuel gas system to accept it.

As noted above, any vent gases, whether resulting from an emergency or not, within flare gas recovery compressor capacity is sent to the No. 5 Gas Plant where it is scrubbed and recovered as fuel gas. If there are flare gas flows beyond the capacity of the flare gas recovery compressors, the gas cannot be compressed to the pressure required to enter the Wet gas system at the No. 5 Gas Plant. In addition, even if additional compressor capacity were available, the amount of gas that could be scrubbed and recovered as fuel gas would be limited by the amount of remaining capacity in: 1) the No. 5 Gas wet gas compressors, 2) the fuel gas scrubbing system, and 3) the fuel gas consumers.

Even if only non-emergency gas was considered, non-emergency flare gas would primarily result from planned turnaround events. This gas would tend to be high in nitrogen or hydrogen and, in general, would be relatively low in sulfur. Therefore, scrubbing this gas would not result in significant emission reductions, but would be very expensive to install and operate. Such systems were discussed above and found to not be cost effective. This analysis was done for all flaring (i.e. emergency and non-emergency). Therefore, limiting the operation of such equipment to non-emergency flaring would only make the system less cost effective.

Based on this review Martinez believes that further expansion of systems for the recovery, treatment and use of flared gases is not a cost effective approach to reducing these emissions (see Attachment 9 for cost effectiveness calculations). The major source of flared gases on a volume basis can be attributed to large flow rate flaring events, especially those of extended duration such as may occur during emergency events or prolonged shutdowns where systems within the refinery are out of fuel gas (and / or hydrogen) balance. Martinez believes that this plan addresses such situations, as well as shorter term, smaller flaring events, and provides a cost effective method of eliminating or minimizing flaring during all situations.

Description of Prevention Measures

As noted above, the potential causes of vent gas quality or quantity issues are numerous. Releases of vent gas to the flare result from an imbalance between the quantity of vent gas produced by the refinery and the rate at which it can be compressed, treated to remove contaminants (sulfur compounds) and utilized as fuel gas. Situations that have the potential to result in vent gas compositions or flows that would make recovery infeasible can be grouped together based on similarity of cause. These general categories, are:

- Maintenance Activities Including Startup and Shutdown
- Malfunctions and Upsets
- Emergencies
- High Base Load
- Reduced Fuel Gas Consumption
- Other Causes

Many of these causes are addressed in other sections. Maintenance related flaring is addressed in Section 3.4.1 including issues of vent gas quality and quantity. Malfunction, Upset, and Emergency related flaring is addressed in Section 3.4.3 including issues of vent gas quality and quantity. The remaining categories are addressed in this section.

<u>High Base Load</u>
A routinely high flow rate to the flare system can limit the additional amount of flare gas that can be sent to the flare system without flaring. Operations monitors the flow to the flare system and investigates when there are significant changes to the vent gas flow to the flares. By routinely monitoring the flow to the flare system, action can be taken early to identify the cause of the additional vent gas and, to the extent possible, take appropriate action. There are various reasons why high base flows to the flare cannot be reduced at a particular point in time. For example, if the source of the high flow to the flare is required for safety purposes such as the safe depressurization of a unit. Such situations can take several hours or longer and, during this time, Martinez would be unable to reduce the high flare flows. Another example would be if maintenance or an upset resulted in a high flare flow for a limited period of time to safely manage the gas. During that time Martinez would be unable to reduce the high flare flows. If such flows result in a reportable flare event, Martinez will conduct a causal analysis to determine whether the failure to reduce the flow was justified.

<u>Reduced Fuel Gas Combustion</u>
Reduced fuel gas consumption can lead to out of fuel balance situations that can cause flaring. This can be caused by energy efficiency improvements or other changes to operating processes. Martinez is committed to improving energy efficiency, while at the same time managing the fuel gas system to reduce the chance of fuel gas imbalance related flaring. As noted previously the Operations Department manages the fuel system to prevent fuel gas imbalance related flaring, to the extent feasible. Operations modifies unit operations at fuel gas generating units to reduce gas make, if needed, to address such situations.

<u>Other Causes</u>
If Martinez identifies any other causes that could reasonably result in vent gas composition or quantities that would make recovery infeasible, Martinez will evaluate the cause and determine whether any action is warranted to address the situation. If any additional actions are identified, Martinez will include this information in the next annual update of the flare minimization plan.

Should a situation still result in a reportable flaring event due to issues of gas quality or quantity, Martinez will conduct an analysis of the cause and consider, during that analysis, what further actions may be warranted to prevent a recurrence. That information will be provided to the District.

50 Unit Flare

The 50 Unit flare was designed so that it would only be used during situations of upsets, malfunctions, or emergencies. During other situations, the 50 Unit Flare system is designed to recover any flare gas generated and send the recovered gas to the refinery fuel gas system for use in fired equipment within the refinery.

3.4.3 Malfunctions & Upsets

This section addresses situations associated with equipment failure or failure of a process to operate in a normal or usual manner. Such situations are generally referred to as "malfunctions" and "upsets". During such situations, vent gas flows to the flare system can be large due to pressure relief valves venting to the flare header or various other process streams temporarily routed to the flare to address the upset situation.

Review of Recurrent Equipment Failures or Upsets

The refinery continues to conduct recurrent failure analysis for flaring events globally. Each event is reviewed to identify the root cause. While a given Flaring Process Unit may be the cause of a flaring event, the true root cause of each event may vary. Martinez has evaluated and continues to evaluate means of minimizing flaring due to Internal Power Loss and electrical system reliability. These Prevention Measures must always be balanced with safety.

Description of prevention measures

The best way to prevent malfunctions and upsets, whether they are recurrent or not, is to take proactive actions to prevent or reduce the chance of such situations. Martinez has a number of programs in place to accomplish this. These include the Mechanical Integrity Program, Predictive and Preventive Maintenance Program, the Maintenance Training Program, and the Operations Procedures and Training Program. Each of these programs is described in more detail below. The purpose of these programs is to ensure that all reasonable efforts are taken to prevent equipment failure and to ensure that the units are maintained and operated by properly trained personnel.

Mechanical Integrity Program

The refinery's Mechanical Integrity Program addresses the integrity of process equipment and instrumentation for safe and reliable operations. The refinery maintenance program covers three types of maintenance: 1) preventative and predictive maintenance, 2) routine maintenance (repair), and 3) turnarounds. Preventative maintenance is performance of equipment inspection and repair based on time and historical knowledge of the equipment. Predictive maintenance involves utilizing technological methods of inspection to determine equipment condition. Preventative and predictive maintenance used in combination determine the inspection and repair frequency of equipment at the refinery. Routine maintenance is the repair or corrective maintenance of equipment as dictated by predictive maintenance, preventative maintenance and equipment condition. A turnaround is maintenance of a process unit on a large scale. A turnaround is the periodic shutdown of a processing unit for cleaning, internal inspection and renewal. The process unit is opened up and its critical components are inspected and repaired during a turnaround. The goal of the Mechanical Integrity Program is to eliminate or minimize equipment failure by maintaining the equipment. This will also eliminate or minimize any releases from that equipment to the flare system.

Predictive and Preventive Maintenance Program

<u>Fixed Equipment:</u>
The Inspection Department has trained inspectors for performing inspections on fixed equipment at the refinery. Fixed equipment includes, but is not limited to equipment such as pressure relief systems, fractionators, reactors, separators, drums, strippers, tanks, exchangers, condensers, piping, etc. The Inspection Department maintains a current list of all fixed equipment, categorized by process, which includes information on the last inspection, next planned inspection and inspection frequency. Records of all equipment inspection are retained for the life of the equipment. The Inspection Department also has a written procedures manual, which contains written details on how to perform certain inspection techniques used to determine equipment serviceability. Examples of techniques used by Inspectors include: visual weld inspection, dry magnetic particle testing, wet fluorescent magnetic particle testing, liquid penetrant examination, Eddy current tube examination, IRIS tube inspection, ultrasonic testing, and radiographic viewing. The Inspection Manual also details procedures regarding how to perform an inspection for certain pieces of equipment. Examples include instructions on how to inspect piping, boilers, air receivers, pressure vessels, furnaces, and exchanger tube bundles. Inspection frequency and methods of inspection are performed according to Industry Codes and Standards and the California State (Cal-OSHA) Safety Orders. For example, pressure vessel inspection is performed according to API Standard 510 (see next paragraph for more information on API 510). The Inspection Procedures are reviewed regularly for accuracy. Any changes to Inspection Procedures are managed through a revision process for tracking changes. The Inspection Procedures Manual is available to employees both electronically through a computer shared-drive and in hard copy at their office.

API 510 inspection code provides a process to ensure that the in-service inspection, repair, alteration, and re-rating activities for pressure vessels and the pressure-relieving devices protecting these vessels are conducted properly. By following this inspection standard, the risk of an unexpected vessel failure is significantly reduced. Pressure vessels that remain in a condition of being suitable for operation reduce the likelihood of taking the vessel out of service during the unit run, which can potentially take the unit off-line. If the vessel needs to be de-pressured safely and quickly, then the potential to flare is a more likely scenario due to the sudden increase in flare header flow and pressure required which may exceed the flare recovery capacity and the flare seal system resulting in a flaring event. Keeping a pressure vessel operational in a "normal" mode reduces the potential for flaring.

<u>Rotating Equipment:</u>

The Rotating Equipment Department performs all inspections and repairs on rotating equipment at the refinery. Rotating equipment includes pumps, compressors, fans, blowers, turbines, engines, gear boxes, motors, *etc*. The rotating equipment group consists of Machinists, Machinery Field Specialists, Vibration Specialists, and Rotating Equipment Engineers. The Rotating Equipment Department maintains a current list of all rotating equipment that is categorized by type of equipment. Rotating equipment is inspected and tested using lubrication checks, oil analysis, visual inspections, vibration monitoring and testing mechanical safety devices. The frequency of these tests and inspections is based upon industry codes and standards as well as type of service. For example, steam turbines are inspected and tested according to the API Standards 611 and 612. Inspection records are maintained on file as hard copies. Vibration records are entered into a computer database for tracking. The Rotating Equipment Department also has a written procedures manual, which contains up-to-date written details on how to perform rotating equipment inspection and tests. The procedures are reviewed regularly and changes are tracked through a revision process.

Maintaining rotating equipment in good operating condition reduces the chance of malfunctions or upsets that can result in flaring. Also, preventive maintenance programs will tend to identify potential problems prior to failure and allow issues to be addressed in a planned manner. This reduces the chance of an unplanned, upset condition that can result in flaring.

<u>Instrumentation and Electrical Equipment:</u>

The Instrument and Electrical Department (I&E) performs all inspections and repairs on instrumentation and electrical equipment at the refinery. This type of equipment includes, but is not limited to, transmitters, controllers, control valves, Distributed Control Systems, analyzers, interlocks, relief valves, power distribution systems, motors, alarms, and programmable logic controllers. The I&E group consists of Electricians, Instrument Mechanics, Analyzer Mechanics and Distributed Control System Technicians. I&E maintains a current list of all electrical equipment and instrumentation. I&E has 13 programs dedicated to predictive and preventative maintenance of instrumentation and electrical equipment. The thermographic survey program is an annual performance of a survey to identify any hot spots in the power distribution system for repair. The Motor Management program addresses motor reliability. The transformer program includes inspection and testing of transformers. The UPS/Battery Program requires quarterly testing of these power sources. The Substation and Switching Station Program addresses inspection and testing of electrical power distribution stations to ensure reliability. The Insulator Washing Program covers the cleaning of high voltage insulators. The Pole Inspection Program covers annual inspection of all power poles in the refinery. The Analyzer Program covers calibration and testing of analyzers, with the results of the tests tracked by computer to predict maintenance requirements. The Vibration Program is performed on motors with the Rotating Equipment Group. The Cathodic Protection System is checked through a monthly inspection program. Control valves are serviced through a Control Valve Management Plan, where a flow-scanning system is used to quantify and record the control valve performance. The Relief Valve Servicing program covers refinery pressure relief systems. The Essential Instrument Program addresses inspection and repair of critical instrumentation. In addition, the Distributed Control System Technicians inspect and test the computer systems that control refinery processes. The test frequencies are specified by instrumentation type and manufacturer specifications. Inspection and test records are maintained on file and tracked by database. I&E has written procedures for performing inspections and tests. These procedures are reviewed regularly and changes are tracked through a revision process. Due to the rapid technological expansion occurring in instrumentation and digital control systems, I&E has more frequent personnel training and procedure reviews than other areas.

Maintaining instrumentation and electrical equipment in good operating condition reduces the chance of malfunctions or upsets that can result in flaring. Also, preventive maintenance programs will tend to identify potential problems prior to failure and allow issues to be addressed in a planned manner. This reduces the chance of an unplanned, upset condition that can result in flaring.

<u>Repair</u>

Routine or corrective maintenance of equipment is performed by experienced Craftspeople. Craft specialties include Boilermakers, Welders, Pipefitters, Exchanger Shop Mechanics, Mechanics, Machinists, Riggers, Carpenters/Builders, Compressor Mechanics, Valve Mechanics, Instrument Mechanics and Electricians. Corrective maintenance is performed on equipment as dictated by predictive maintenance, preventative maintenance and equipment condition. Operator surveillance during their routine inspections of the units is also used for determining the need for repair of equipment. Documentation of repairs is developed and maintained in the applicable equipment folders for the life of the equipment. The repairs may be performed in maintenance shops or in the field. The refinery has specialized repair shops for carpenter work, welding, machine work, instrument and electrical repair, and exchanger repair. Inspectors perform inspections and tests on fixed equipment and maintenance craft personnel perform the repairs. These repairs are typically performed in the field. The Maintenance Department has written procedures for corrective maintenance of equipment. These procedures are available on the refinery intranet as well as in hard copy. Rotating equipment is both inspected and repaired by Rotating Equipment Department personnel. These repairs may be performed in a shop or in the field by Machinists or Machinery Field Specialists. The Rotating Equipment Department has written procedures for repair of the equipment. These procedures are reviewed annually and tracked through a revision process. I&E repairs electrical equipment, instrumentation and relief valves. These repairs may be performed in the shop or in the field by the appropriate Craftspeople. I&E has written procedures for repair of their equipment. These procedures are regularly reviewed and changes are tracked through a revision process.

Repair work is planned by maintenance planners. They develop detailed plans for conducting repairs in a safe manner. Depending upon the scope of work, the proper information and materials are assembled for the repair work to proceed. In addition, the appropriate safe work permit requirements are identified for the job. Upon completion, repair records for equipment specific repairs are retained in hard copy or tracked by computer database.

Equipment repairs minimize flaring by properly maintaining equipment to minimize the chance of an upset or unplanned shutdown that can result in flaring.

Turnaround
A turnaround is maintenance of a process unit on a large scale. A turnaround is the periodic shutdown of a processing unit for the cleaning, inspection and renewal of worn parts. The process unit is opened up and its critical components are inspected and repaired during a turnaround. Due to the size of the project, turnarounds take 6-24 months of planning. Three criteria determine the frequency of unit turnarounds; they are the type of unit, the history of the unit and specific government regulations. Typically, units undergo a turnaround every two to five years. Large unit turnarounds may require the use of 1000 contract craftspeople to complete the repairs.

Maintenance turnarounds minimize flaring by properly maintaining equipment to minimize the chance of an upset or unplanned shutdown that can result in flaring.

Maintenance Training Program
Staff training helps ensure that activities such as equipment inspection, problem identification, repairs and quality control of all equipment are conducted properly and that problems are identified and addressed to keep the equipment functioning properly. Properly functioning equipment reduces the likelihood of equipment malfunctions that can cause unit upsets which can result in flaring. This will also reduce the chance of having to take equipment off-line during the unit run, which can potentially lead to a flaring event.

Maintenance Craftsperson Training
The refinery employs experienced Journey-level Craftspeople in a number of disciplines to perform maintenance at the refinery. Craft disciplines include Boilermakers, Welders, Transportation (drivers), Pipefitters, Exchanger Shop Mechanics, Mechanics, Machinists, Vibration Specialists, Riggers, Carpenters/Builders, Compressor Mechanics, Valve Mechanics, Instrument Mechanics and Electricians. The refinery hires only Journey-level craftspeople. All Craftspeople must pass a written and practical exam to demonstrate their skills prior to hire. All Craftspeople are trained on the overview of the refinery processes. On a regular basis, refresher training is performed and conducted in modules. These training modules may include, but are not limited to: forklift operations, respirator fit testing, fresh air, blinding, torqueing, hose use/selection, gasket selection, fall protection, lead abatement, asbestos, lock-out/tag-out, hazardous energy, confined space, hot work, repacking valves, rebuilding site glasses, bleeder reamer use, turbine repair, laser alignment of equipment, staging/scaffolding, rigging/crane, highlift, and leak repair. During the lock-out/tag-out training module, there is an emphasis on understanding the hazardous energy sources. All Craftspeople must complete an exam at the conclusion of each training module. Vibration Specialists responsible for performing predictive and preventative maintenance on rotating equipment have been certified in their craft by attending in-depth training courses from the Vibration Institute and/or manufacturers' training courses. Machinists who perform vibration analysis on rotating equipment have received 12 hours of classroom training in addition to field training. The instrument mechanics and electricians have skills training annually, including a specialized Computer Based Training (CBT) for their craft. Under special circumstances in 1999, all refinery Maintenance Craftspeople repeated all training modules described above (with the exception of vibration training). Training records are retained.

Inspector Training
Inspectors perform inspections of structures and fixed equipment to ensure the integrity of the equipment, and thereby, the safety of personnel and property. The inspection personnel receive specialized training to assure that they are able to successfully perform their job. All Inspectors must have five years' experience in operations, welding and/or boilermaker craft. They must pass a written exam as well as a vision test. The Inspector initially is trained in a company developed training program involving in-house and off-site training. The course curriculum is focused on non-destructive testing and equipment visual inspection. Specific courses may include: Introduction to non-destructive testing, visual weld inspection, radiation safety and radiographic examination, math and physics for industrial technology, ASME pressure vessel and boiler codes, magnetic particle examination, ultrasonic examination-thickness gauging, color contact penetrant examination, API 510 on pressure vessels, API 570 on piping and API 653 on tanks. Certification of course completion is performed by written exam. All training is paid for by the refinery. The Inspector training is compliant with ASNT SNT-TC-1A and API guidelines. Recertification, as specified in ASNT SNT-TC-1A and API guidelines, occurs every 3 to 5 years depending on the method and/or certification. Inspector training is tracked by the Inspection Department by database, including when training has been completed and refresher training is due. In addition, hard copies of all Inspector certifications are kept on file. Training records are retained.

General Safety Refresher Training
In addition, all Maintenance Craftspeople and Inspectors must complete an annual CBT and classroom training that addresses chemical hazards, the emergency action plan, electrical safety awareness, safe work permitting, Personal Protective Equipment (PPE), and respiratory protection. The training records of all maintenance personnel, except Inspection, are kept by the Training department.

Quality Assurance
The quality of maintenance repair work on fixed equipment is verified by Inspectors. The Inspectors perform or oversee specific tests after the repair is complete to assure that the repair has been performed properly and with appropriate materials. The nature of the tests used for quality assurance depends upon the type of work performed and is typically specified by an Inspector. To assure the proper material has been used in building or repairing a process, the refinery has a Positive Materials Identification Procedure. This procedure involves the use of an analyzer capable of identifying metal alloys. Rotating equipment quality assurance is performed by Supervisors. They perform visual inspections, pressure testing (where and when applicable) and start-up checks. In addition, spare parts original manufacturer's number is tracked along with the manufacturer provided documentation (material certification papers) to ensure the right parts have been installed into the proper service. Instrument and Electrical repair quality is assured by strict use of original equipment manufacturer spare parts. Repair of relief valves are performed by VR qualified shops, these specialized shops have been certified by a national board to perform work on relief valves.

Quality control of repairs and maintenance helps to ensure that the repairs and/or replacements of components are correct and meet all requirements necessary for the particular job. This reduces the chance of an unplanned outage of the equipment which can cause a unit upset or shutdown which, in turn, can result in flaring.

Operations Procedures and Training Program

Operating Procedures

The refinery has written Operating Procedures for all operating units. The purpose of the Operating Procedures Program is to develop, implement and maintain operating procedures that provide clear instructions for safely conducting activities involved with refinery processes. Operating Procedures are organized into Operating Procedures Manuals for each process unit. In addition, there is an Operating Manual for each unit. Every Operating Manual contains all the process information, engineering data, and reference sources that is required to operate the unit in a safe, efficient, reliable and environmentally sound manner.

The written Operating Manuals were developed from a standard template. All Operating Manuals follow a consistent format that is divided into six sections. There is an introduction section, a process safety and environmental section, an equipment description section, a process control variable section, a troubleshooting section and a failure prevention section. In addition, both the Operating Procedures and Operating Manuals contain information so that the Operator can take appropriate action to safely perform any of the following: an initial unit start-up, normal operation of the unit, shutdown of the unit during an emergency, operation of the unit during an emergency, a normal shutdown of the unit, a startup after a turn around and a startup after an emergency shutdown. The Operating Procedures Manual and Operating Manual also contain information regarding the consequences of deviating from normal operating parameters and the steps to correct deviations and avoid deviations. In addition, the Operating Procedures Manual and Operating Manual contain information about the process safety systems and how they function. Written temporary Operating Procedures are developed if needed.

The initial development of the Operating Procedures involved Operators, Unit Supervisors, Shift Supervisors, and outside Contractors, all of whom are collectively referred to as Subject Matter Coordinators (SMCs). The SMCs wrote the initial versions of the Operating Procedures. Review and certification of the Operating Procedures occurs at regular intervals. The Area Supervisor is responsible for the review and certification of their completeness and accuracy. Operators are typically consulted during this review. During the review process, revisions to the Operating Procedures may be warranted. Any revisions to the Operating Procedures are managed through Management Of Change and operators are trained on the revisions. Hard copies of Operating Procedures are kept in each control room and at the training center. In addition, electronic copies are available on the refinery intranet.

The refinery has a permitting program to address the safe work practices involving lockout/tagout, confined space entry, opening process equipment/piping and access of personnel other than operators to the process area. The refinery also addresses Hot Work by permit. The permit template was used to address safe work practices so that maintenance work would be planned and performed in a consistently safe manner. The content of the permit forms is in compliance with Cal-OSHA regulations specific to each of the areas previously mentioned. The safe work practices and policies are available on the refinery intranet for all employees. In addition, hard copies of the policies and permits are available in unit control rooms and at the Shift Superintendent's office. Safe work practice permitting is continuously audited by the Health and Safety Department and the results are posted monthly on bulletin boards refinery-wide for employees to read. The Field Safety Supervisor manages all changes to the safe work practices and permits. Employee involvement on development and maintenance of the safe work practices occurs through the Joint Health and Safety Committee. Employees are informed of changes through the weekly/monthly safety meetings, bulletin board postings, email distribution and other appropriate methods.

Eliminating or minimizing flaring is an ongoing general operating practice. However, this has not yet been included in all startup or shutdown procedures (many operating procedures do not involve flaring issues, so startup and shutdown procedures are more pertinent). At least 20% of the shutdown procedures currently include references to eliminating or reducing flaring. As the startup and shutdown procedures are revised, such references will be included.

Operating procedures reduce flaring by instructing operators to route streams to alternate locations during depressurization of equipment, by instructing them to depressure slowly, and by instructing them to notify shift supervision before conducting depressurization operations.

<u>Operator Training</u>
The objective of the training program is to ensure that employees involved in the operation and maintenance of processes are trained in the tasks and information necessary to safely and effectively perform their work.

An awareness of the importance of minimizing flaring may be the most effective means of actually reducing flaring. Operators who are trained how to operate their units safely and efficiently, depressure equipment according to operating procedures, and communicate with other units effectively play a vital role in the overall goal to reduce and control flaring activities. By the operator being aware of the goal to eliminate or reduce flaring, actions will be taken consistent with that goal. Effective communication between units helps to coordinate what is being sent to the flare and minimize the chance of exceeding the flare recovery system capacity. In addition, operator training reduces the chance of upsets or other unplanned events that can result in flaring.

<u>Initial Operator Training</u>
The new Operators begin with six weeks of classroom training. The classroom training covers safety training, reviewing safe work practices, respiratory protection, PPE, hearing conservation and hazard communication program (this program covers how to find and use MSDSs and other portions of PSI). The new operators are also trained to the First Responder Operations Level as required by the HAZWOPER regulations. This training covers defensive actions in the event of an accidental release. In addition to the HAZWOPER training, the new Operators also receive Incipient Fire Training. The curriculum also covers a general introduction to refinery processing, followed by training modules on refinery equipment, including pumps, compressors, heat exchangers,

distillation towers, valves, instrumentation, furnaces, boilers, cooling towers and electrical systems.

After the classroom training is complete, new operators begin practical training in the field. They study the Operating Procedures and Operating Manuals specific to the unit on which they are assigned. They become skilled at the details of their job, including how to perform procedures. They also learn more about their specific process unit, including its process chemistry. The new operators learn the operational details covered in the six sections of the unit's Operations Manual, with particular emphasis on process control and safety systems. The process control emphasis is on critical operating limits (COL), the consequences of operating outside the COL and how to bring the unit back under control if it has deviated outside of the COL. The safety system emphasis focuses on the importance and function of the unit safety systems.

The refinery has several units with state-of-the-art computer controls. The Operators assigned to these computer-controlled units receive additional training on computer simulators. The simulators allow the operators to practice controlling the process units under a variety of events. The simulators are a dynamic training tool, they can mimic the entire process unit and show the Operator the consequences of changing variables during process operations. Some of the unit simulators also perform scenario training. The scenarios can mimic process upset conditions that would require the operator to safely shut-down the unit. The Operator can then practice how to safely restart it.

Upon completion of the initial training, operators are given a written exam and a practical exam. The written exam covers information specific to the Operations Manual in their unit. The practical exam addresses the procedures they perform and specific details of their unit. Finally, the new operator must pass the qualification process, which is similar to an oral exam, where they demonstrate the skills they have learned to be a qualified operator. This completes the operator's certification of training.

<u>Refresher Operator Training</u>
Operator refresher training is conducted every three years. It covers the procedures and operations manual of the specific unit on which the operator is assigned. As part of their refresher training, operators must pass a written exam and a practical exam in addition to the qualification process. In addition, each year all employees, including operators, complete CBT modules on many of the topics covered in the initial operator training course. Under special circumstances in 1999, all refinery operators repeated the initial operator training and were re-certified in the same manner as described previously under initial operator training.

<u>Training documentation:</u>
The Training Department maintains records on all employee training. Initial Operator training and refresher training is tracked through a database. The database is programmed with the required training curriculum for each employee. Employee training and testing is entered into the database upon its completion; this includes training on CBTs, classroom, as well as any written or verbal test results. Training records for certain courses or safety meeting attendance are kept in hard copy in a central filing system.

In spite of such extensive efforts, equipment malfunction and upset situations can still occur. Should a malfunction or upset situation occur that results in a reportable flare event, Martinez will conduct an analysis of the cause and consider, during that analysis, what further actions may be warranted to prevent a recurrence. That information will be provided to the District.

3.4.4 Other Potential Flaring Events

Should a reportable flare event occur due to any other cause not already noted in this FMP, Martinez will conduct an analysis of the cause of that event and consider, during that analysis, what further actions may be warranted to prevent a recurrence. That information will be provided to the District.

Flare Testing
From time to time, testing of a flare may be required to ensure that it is operating or will operate properly. Typically this is done after construction of the flare or any significant repair or maintenance to a flare. During these situations it is important to conduct a controlled test to ensure that the flare or flares will function properly. For example, if a flare tip required replacement (due to corrosion or some other cause), a test of the flare might be performed to ensure that the replacement tip would perform properly during a flaring event. Historically, such testing has rarely been required. The test is typically performed by sending fuel gas to the flare. Typical flow rates during the test are about 5- 10 MMSCFD and the typical time to conduct a test is about 15 minutes at a time. Martinez will provide a test protocol to the BAAQMD for approval prior to conducting any flare tests.

Delayed Coker Flare Prevention Measures
As a part of the design of the Delayed Coker Revisions, prevention measures were included in the design and operation to minimize or eliminate flaring. These measures ensure that all normal operations and maintenance venting is routed to the wet gas system instead of the flare system. Therefore, there is no impact of routine operation and maintenance flare gas flow from the Delayed Coker on the refinery flare gas recovery. This is described in more detail below.

In the delayed coker, coke is produced in four large coke drums. The coker feed, vacuum residuum, are fed to the coke heaters from the fractionator. The coker heaters heat the feed to approximately 950° F. The bottom of the fractionator serves as a surge tank for the coke heater charge pumps. The heated feed is sent to two of the coke drums. Upon entering the lower pressure of a coke drum, the cracked hydrocarbons flashes and passes overhead, is quenched with heavy coker gas oil, and then enters the bottom of the fractionator. The finely divided carbon particles formed in the cracking of the large chain hydrocarbons remain in the coke drum, coalesce and form solid coke particles. These particles solidify in a matrix and build up in the drum, filling it to a predetermined level.

Two drums are online filling with coke while the other two are offline either having the coke removed from the drum or being prepared to be switched back to online. A filled coke drum is stripped of residual vapors with steam, and then quenched with water. The vapors produced by quenching are routed to the new quench tower closed blowdown system to remove coke particles and oil droplets prior to being condensed in air-cooled condensers. The remaining vapors are routed to the existing wet gas compressors at No. 5 GP and used for fuel gas and products (propane and butane).

The use of the quench tower closed blowdown system allows for the recovery of hydrocarbon from the coke drums prior to switching them off line and removing or cutting the coke. This design was developed so that the vapors would not need to be sent to the flare. In addition, the operating procedures for the delayed coker startups and shutdowns do not require flaring during the startup of the unit. Any hydrocarbons generated during startup or shutdown are recovered in the wet gas compressors at No. 5 GP. In addition, venting associated with maintenance operations will also be sent to the wet gas system and will not be sent to the flare system. The flare system only receives vent gases associated with an upset or breakdown situation. Martinez has also tied the Coker Flare into the existing flare system, and the associated recovery compressors, to recover any small leaks or minor process upsets that may occur to avoid flaring for these events. Lastly, the other general prevention measures also apply to the Coker Unit.

The Coker Modification Project included various connections to the flare header, through a flare knockout vessel. These include hydrocarbon relief valves (safety control and manual) and various hydrocarbon drains used to hydrocarbon free the equipment prior to maintenance. More specifically, there are Coke drum relief valves, Fractionator relief valves, fuel gas relief valves, Blowdown Quench System relief valves, and Strainer relief valves. There is also a valve to route Settling Drum Off Gas to the flare system (which is normally closed with the off gas normally sent to the No. 5 GP) and a natural gas purge to ensure the flare header is free of oxygen (which is recovered by Flare Recovery Compressors).

In addition, there are various pump vents/drains, heater tube vents/drains, and strainer drains that are routed to the flare header. There are also connections to cross connect the various flare headers. The 42" flare header is designed for a maximum rate of 266 MMSCFD.

The Coker Modification Project relief valves are routed to a flare knockout vessel and the gas is routed to the refinery flare system. The Coker Flare is required to ensure that, during all relief events, there is adequate flare capacity.

The Coker Flare is operated as a part of the existing, staged main refinery flare system. Additional details on the seal pot levels and header system are provided in Section 3.1.1 of the FMP and the main flare simplified flow diagram.

The operation of the Coker Flare is consistent with flare minimization. The addition of the Coker Flare to the refinery main flare system retains the overall flare minimization of the flare system as a whole. There is no routine flow to the flare system from the Delayed Coker and all the existing flare minimization efforts, including the flare gas recovery system, will continue.

The Coker Modification Project directionally reduced the chance of a fuel gas imbalance situation, which reduced the chance of flaring. The Delayed Coker produces less fuel gas than the historic Fluid Coker. In addition, the two furnaces at the Delayed Coker use a combination of fuel gas and natural gas, which increased fuel gas use. (The Fluid Coker combusted coke for heat whereas the Delayed Coker uses fuel gas/natural gas for heat.) Therefore, since less fuel gas is produced and there is more fuel gas used in the refinery, the chance of a fuel gas imbalance situation is reduced (i.e. a situation where there is temporarily more fuel gas being produced than fuel gas being consumed).

The Delayed Coker generates fuel gas continuously. However, when switching a drum, the amount of gas make reduces to about 75% of the previous amount (since the drum being switched into is not quite as hot as the drum that had been online previously). Therefore, additional natural gas needs to be added for about 2 hours after a drum switch. This serves to further reduce the chance of a fuel gas imbalance situation that could result in flaring.

50 Unit Flare Prevention Measures

As a part of the design of the 50 Unit Flare, prevention measures were included in the design and operation to minimize or eliminate flaring. These measures ensure that all normal operations and maintenance venting is routed to the fuel gas system instead of the 50 Unit Flare. Therefore, there should be no flaring associated with routine operation and maintenance at the 50 Unit. This is described in more detail below.

The 50 Unit Flare was installed as a part of a project to replace the 50 Unit Atmospheric Blowdown Tower. Various maintenance streams and pressure relief valves had been routed to the atmospheric blowdown tower. This project removed the existing atmospheric blowdown tower and replaced that system with the 50 Unit Flare and flare gas recovery system.

The 50 Unit flare gas recovery system includes a flare gas header and compressors to recover flare gas generated and send it to the refinery wet gas system where it is treated and used as fuel gas. The 50 Unit flare gas recovery system has been designed to handle scheduled routine maintenance, as well as scheduled major turnaround maintenance. The system includes a small compressor to handle the day-to day small maintenance and purge streams that may be generated. In addition, the existing spare 50 Unit wet gas compressor has been lined up and used for recovery of the vapors during de-pressuring and equipment steam-out of large process equipment during and outside of the turnarounds when non-condensable hydrocarbon loading is relatively high in the 50 Unit flare gas recovery system header. The existing spare wet gas compressor will also serve as a common spare between the flare gas recovery service and the wet gas service. Since equipment de-pressuring and steam-out operations are well planned operations, sufficient time is available for changing over from the small flare gas recovery system compressor to the existing wet gas compressor and vice versa. The existing spare wet gas compressor is expected to be used for the flare gas recovery service only for short periods of time during the beginning of the steam-out operation, when non-condensable hydrocarbons are present in relatively large quantities. Control valves have been provided on the steam-out lines from large process equipment for controlling steam-out rates to minimize the chance of the 50 Unit flare liquid seal being broken during the steam-out operations. A spill-back control valve has also been added to the design to help keep the wet gas compressor suction pressure, when in flare gas recovery service, at a constant pressure lower than the normal flare gas recovery system pressure.

In addition, a steam condenser has been added to the system design. This condenser allows the steam sent to the flare recovery system during maintenance steam out situations to be condensed, reducing the overall flow rate to the flare gas recovery system.

Small Flare Events
Martinez reviewed small flaring events from 7/1/15 through 6/30/16 that, due to the total volume or low emissions, did not reach the trigger levels for a flare causal analysis. An analysis of the average emissions associated with these five small flare events was conducted. Days with flare events that triggered a flare causal analysis and days of no flaring were excluded from this review. The average flare emissions per small flare event day were 19 lb/day of methane, 76lb/day of non-methane hydrocarbon, and 107 lb/day of SOx. One of the small flare events was related to issues with the refinery fuel gas mixpot seeing increased wet gas production, which releases the excess gas to the flare header under pressure control. Other incidents were related to general unit shutdowns and startups.

Nonetheless, a review of the causes for such events was conducted by interviewing key Operations personnel in each of the operating areas to identify situations that they recalled leading to small flare events. Planned and completed actions to eliminate or reduce flaring from small flaring situations have been noted in Attachment 16.

3.4.5 Summary
Martinez believes that the prevention measures described in this FMP are the most effective in minimizing flaring from the refinery. No other measures were considered to reduce flaring, beyond what is contained in this FMP.

Work practices to reduce flaring are written in procedures. In addition, Martinez has developed a procedure to consider flaring impacts and potential mitigations during more routine maintenance efforts. Martinez has modified the past maintenance project planning process to evaluate whether certain maintenance activity could reasonably result in flaring and, if so, consider what actions might be taken to reduce or eliminate the flaring. As noted above, should significant flaring (i.e. flaring over 500,000 scf/day) still occur, a causal analysis will be performed to determine whether there are reasonable methods to reduce or eliminate such flaring in the future. There are no other new or revised procedures planned for implementation to reduce flaring.

As noted in Section 3.4.3, Description of planned prevention measures, during the pre-planning process for planned major maintenance reducing process flow rates to eliminate or reduce flaring will be considered. Since every planned major maintenance activity is unique (i.e. the equipment being shut down, units being shut down, and other operating parameters at the time of the shutdowns), Martinez believes that this method will be the most effective in identifying methods to eliminate or reduce flaring. As noted in Section 3.4.2, many of the gas quality or quantity issues are related to planned major maintenance activities. The remaining causes of gas quality or quantity issues are: 1) malfunction, upset, or emergency (as described in Regulation 12-12-201) situations, 2) high base load situations, 3) reduced fuel gas consumption situations, and 4) possible other causes. During malfunctions, upsets, or emergency situations, reducing process flow rates to eliminate or reduce flaring will be considered when the situation is stable and any issues of safety have been addressed. High base load situations would not normally result from unit rate issues. However, if in the specific situation reducing process flow rates has the potential to eliminate or reduce flaring, it will be considered at that time. During situations when the fuel gas system is out of balance, reducing process flow rates to eliminate or reduce flaring will be considered (when the situation is stable, since these situations can occur during malfunction, upset, or emergency situations). Lastly, if any other cause is identified that results in flare gas quality or quantity issues, as a part of the evaluation noted in Section 3.4.4, reducing process flow rates to eliminate or reduce flaring will be considered.

4.0 Capital and Operating Cost

In order to allow estimation of total installed capital cost for additional flare gas compressor capacity, a series of cost curves for each of the necessary components of the system have been developed. This section defines the design of the "model" systems used to develop cost data and then presents the data.

4.1 Operation of Flare Gas Systems with Incorporation of Storage

The systems that ENSR developed pricing for are shown in the attached sketches. The sketches show a very much generalized flare gas recovery system and do not represent the actual configuration at any refinery. A typical flare gas recovery system is shown in Attachment 10. Operation of these systems is envisioned as follows:

Both existing and new flare gas compressors (exclusive of any spare units) would operate continuously. During normal operation the volume of gas they are capable of drawing from the flare gas header would be greater than the volume available, so a portion of the discharge volume would be recycled to the suction side of the compressors via a pressure control loop. Inter-stage cooling would prevent the temperature rise from exceeding design limits. Normally the volume of gas from the flare gas header and other process sources would be less than the total needed for process heaters and boilers. Natural gas would be used to make up the shortfall.

<u>System with Gas Holder</u>
At normal flow rates, pressure in the flare gas header is set by the suction-side pressure control system for the flare gas compressors as described above. When the flow of flare gas exceeds the volume that can be handled by the flare gas compressors, treaters and fuel gas system, the pressure in the flare gas header increases. This increase in pressure is sufficient to begin to lift the "piston" in the gas holder, effectively storing any excess flow that the recovery system cannot handle. Once the gas holder fills completely, if flare gas flow rates continue to be in excess of what the recovery system can handle, the pressure in the header will continue to rise until it exceeds the pressure corresponding to the depth of the flare seal, allowing any excess gas to be flared. As the

flow of gas to the flare gas header decreases, first flaring will cease, then as the pressure in the header continues to fall, gas will flow from the gas holder to the suction side of the flare gas compressors, until the gas holder has been emptied. This system is shown in the figure titled "Flare Gas Recovery with Gas Holder" (see Attachment 11).

System with Storage Sphere

If the volume of gas supplied to the fuel gas header were to exceed fuel requirements at the heaters, pressure would rise in the fuel gas header and gas would be diverted from the flare gas compressor outlet to the storage sphere. This system is shown in the figure titled "Flare Gas Recovery with Storage Sphere" (see Attachment 12). If the pressure in the sphere were to reach the compressor discharge pressure, it would stop filling, and the situation would be equivalent to that which exists with the current system when flare gas compressor capacity exceeds demand.

Gas would be returned from the sphere to the flare gas header based on header pressure. The flare gas compressors are configured to control inlet pressure at a point below where the flare seal would be broken. The storage sphere would have a pressure control system that would allow gas to flow from the sphere to the flare gas header when the header pressure was at or below a set point slightly higher than the flare gas compressor suction-side set point. This would have the effect of keeping the flare gas compressors loaded at their rated capacity whenever there is excess flare gas in the sphere to work off. When the flow of flare gas to the flare gas header exceeds the volume that can be accommodated by the treaters, process heaters and boilers, the pressure in the flare gas header would rise and flow from the sphere to the header would be stopped by the control system.

4.2 Flare Gas Storage System Options Total Installed Cost Estimation

A series of curves showing total installed cost (TIC) for installation of additional flare gas recovery capacity are presented in this section. They were developed primarily using cost data compiled from projects completed at U.S. refineries and shared with WSPA. This information was supplemented using current quotations from equipment vendors. Please note that steel costs have been escalating quickly and are continuing to increase. Therefore, the steel costs used in this analysis are likely understated. In addition, a significant amount of construction cost data used for this analysis was for construction outside of California. The cost of construction in California, and particularly the Bay Area, is significantly higher than in other regions of the country. Therefore, the construction costs used in this analysis are likely understated, as well.

Vessel Costs

Cost estimating curves (see Attachment 13) were developed for three flare gas storage options. The curves are based on gas storage in: a 40-psig spherical tank, a 120-psig spherical tank, or a conventional gas holder.

The spherical tank costs were based on quotes from CB&I for a 60-ft diameter tank, at operating pressures of 40 psig and 120 psig. A 60-ft diameter tank was used as it is near the largest economical size for a spherical tank. Estimated total installed costs include stress relief, foundations, erection, and painting. In developing the cost curves, storage volumes greater than the 60-ft diameter tank can provide are achieved by using multiple tanks. Therefore, cost data points for storage volumes greater than that for a 60-ft diameter tank were calculated based on multiplying the number of tanks by the cost for a single tank. For storage volumes less than that of a 60-ft tank, the $6/10^{ths}$ rule was used to calculate the cost for that volume. The $6/10^{ths}$ rule takes the original cost, multiplied by the ratio of the smaller capacity to the larger capacity to the 0.6 power ($(C_a/C_b)^{0.6}$). In general this rule is valid within +/- 75% of the original capacity.

The cost for the waste gas holder was developed based on design utilizing a 100-ft diameter tank, with a minimum height of 38 ft. and a maximum height of 60 ft. The difference between the minimum and maximum heights accommodates the surge volume of the tank. The tank cost was based on 1-inch thick carbon steel walls. The weight of steel needed was calculated, and the cost of rolled carbon steel per ton was used to calculate the raw cost of materials. Installation, painting and foundation costs were factored from the cost for the basic tank to allow development of a total installed cost. The method for calculating the cost for larger capacities and smaller capacities is identical to the method that was used for the spherical tanks.

Compressor Costs

The flare gas compressor cost curve (see Attachment 14) was developed from eight data points provided by the WSPA membership. The data points used for total installed cost were based on a flare gas compression system with a reciprocating compressor, with the exception of two systems which used a liquid ring compressor system. Costs shown are the total installed cost including all coolers, knockout pots, instrumentation and piping needed for a complete, functioning system. Where an installation consisted of multiple small compressors, the total installed cost was divided by the number of compressors to allow calculation of cost as a function of compressor size. Cost information from previous years was adjusted to a 1st quarter 2006 basis using the CE Plant Cost Index. A logarithmic trend line was used to summarize the data in a cost curve.

Gas Treatment Costs

The gas treatment system cost curve (see Attachment 15) was developed based on five data points, fit to a logarithmic trend line. In some cases it was necessary to separate out the cost for the treater portion of a project where total installed costs for several project elements were reported as a lumped value. Total installed costs for system capacities less than 8 MMSCFD are representative of system debottlenecking projects.

4.3 Flare Gas Storage System Operating Costs

A spreadsheet (see Attachment 9) has been developed for estimation of the operating costs resulting from the addition of additional flare gas recovery capacity. The spreadsheet is based on the BAAQMD cost-effectiveness guidelines for BACT using the "levelized cash flow method". Cost effectiveness is calculated as the annualized cost of the abatement system ($/yr) divided by the reduction in annual pollutant emissions (ton/yr). The spreadsheet has been populated with information based on the hypothetical installation of the 2 MMSCFD flare gas recovery system described in Section 3.4.2 above.

Attachment 1

Wet Gas, Fuel Gas, and Flare Gas Recovery System Descriptions

Vent Gas Recovery Systems - Overview

There are three systems to recover vent gas streams. They are the Wet Gas system, the Flare system, and the Vapor Recovery system. The Wet Gas system can handle gas streams that are above a pressure of about 10 psig. Lower pressure gas streams are typically sent to the Flare system since there is inadequate pressure to get into the Wet Gas system. The Vapor Recovery system recovers vapors from cone roof tanks, marine loading, and a few other very low pressure streams. Wet Gas typically is routed to the No. 5 Gas Plant where it is combined with the No. 5 Gas Plant produced gas, treated to remove H2S, and sent to the Fuel Gas system. If the No. 5 Gas Plant is down, the wet gas streams can be sent to the No.4 Gas Plant. However, the capacity of the No. 4 Gas Plant to handle these wet gas streams is lower than that at No. 5 Gas Plant. A block flow diagram of the relationship between the Wet Gas, Flare Gas, Vapor Recovery and Fuel Gas systems is provided in Figure 1.

Wet Gas System

Wet gas is comprised of off-gasses from various units that are usable as fuel gas. The wet gas system provides an alternate destination for gasses, which would otherwise be sent to flare. The refinery wet gas system consists of 4 major pipelines which connect the suppliers of wet gas such as the FCC and the crude units to the #5 Gas Plant. Typically, that is when No. 5 Gas Plant is in operation, the No. 5 Gas Plant collects the wet gas streams in the refinery, compresses those gases, separates out heavier gasses like propane and butane, and treats the remainder to remove H2S. This treated gas is then sent to the Fuel Gas system. When the No. 5 Gas Plant is shut down, the refinery wet gas streams are diverted to the No. 4 Gas Plant, where similar processing takes place. As noted above, the No. 4 Gas Plant has a lower capacity to handle these wet gas streams than the No. 5 Gas Plant.

Flare Gas System

The 24 inch diameter, 42 inch diameter, and two 48 diameter flare headers collect low pressure gases and send them to the flare area. At the flare area, a recycle compressor draws flare gas from the flare headers, compresses the flare gas, and sends it to the No. 5 Gas Plant for recovery as wet gas.

The primary reduction in flare gas comes from the flare recovery compressors directing gasses from the flare headers into the wet gas system where they are converted to fuel gas as described above. Additionally, when some equipment/units are taken out of service, they can be depressured to the wet gas system instead the flare system, if the pressure is high enough to get into the wet gas system.

There are several limitations associated with this process. The flare recovery compressors can only compress about 5 MMSCFD. If the flow to the flare headers is more than 5 MMSCFD, the excess gas will be directed to the flares. Also, if the wet gas system is already at maximum capacity, the flare recovery compressors will be limited to avoid over-pressurization problems at the No. 5 Gas Plant (excess gas going to the No. 5 Gas Plant are directed to flare, so it would just result in a recycle loop). Additionally, if the refinery is producing more fuel gas than it is consuming, the flare gas recovery will be ineffective since the flare gas will further increase the amount of fuel gas that will then be sent to the flare as the fuel gas pressure exceeds its set point. In such cases, the refinery will typically cut rate/severity at the FCC or rate at the Coker to restore balance to the fuel or wet gas systems.

Vapor Recovery System

The vapor recovery system is comprised of pipelines which route very low pressure streams to the No. 1 Gas Plant where the gas is compressed and routed to the 40 psig fuel gas system. Tank vents from cone roof tanks and the vapors recovered by the Marine Vapor Recovery system are the primary sources of gas to this system. Various other low pressure streams that are piped to the vapor recovery system can also be routed to this system.

Fuel Gas System

The Fuel Gas system includes gases produced in the No. 5 Gas Plant and No. 4 Gas Plant, as well as recovered vapors from the Wet Gas system and recovered Flare Gas. It also includes gases recovered from the Vapor Recovery system which includes tank vapors and vapors from the Marine Vapor Recovery system. In addition, No. 1 Hydrogen Plant off-gasses are sent to the fuel gas system (see Figure 1). Purchased natural gas is added to the Fuel Gas system to make up for any shortage between the fuel gas produced and consumed, maintaining pressure control in the system. Lastly, propane or butane can be added to the Fuel Gas system, if needed, to increase the BTU content of the fuel gas. Fuel Gas system production and consumption rates are provided in the section below.

The fuel gas is sent to the refinery furnaces and boilers, the Foster Wheeler Cogeneration facility, the No. 2 Hydrogen Plant, the Chemical Plant (i.e. Sulfur Plant, Ammonia Recovery Unit, and Sulfuric Acid Plant), and the DuPont Clean Technologies/MECS Inc. catalyst facility to provide a source of energy to support the various processes.

There are no specific fuel gas quality specifications, but there are general levels we attempt to meet for various parameters. For example, we attempt to meet a BTU content of about 1000 BTU/scf and maintain an oxygen level below 1%. We do not have any targets for molecular weight or specific gravity. We also do not have any alarms on the molecular weight of the flare gas. In addition, we do not have a specific target for nitrogen levels, but try to minimize the amount of nitrogen introduced into the fuel gas. Lastly, there are no hydrogen content specifications for fuel gas. However, the No. 5 Gas Plant operators monitor the operation of the wet gas compressors (e.g. the flow and RPMs). If the operation of the wet gas compressors begins to become erratic, they limit the flare gas recovery flow to maintain wet gas compressor operational stability.

Wet Gas and Fuel Gas Production and Consumption Rates

Typically, the refinery producers will generate 70-90 MMSCFD of wet gas. After being processed at the No. 5 Gas Plant, where butane and propane is recovered, about 40-60 MMSCFD of fuel gas is produced. This gas is mixed with 5-10 MMSCFD of fuel gas from the No. 4 Gas Plant, 1-5 MMSCFD from the vapor recovery system, and 0-6 MMSCFD of hydrogen bleed from #1 Hydrogen plant. These streams are supplemented with natural gas purchased from PG&E which averages around 5 MMSCFD to balance the supply of fuel gas with the demand.

There is limited flexibility to increase refinery consumption of fuel gas. This can be done via three methods. First, by switching electric drivers of rotating equipment to steam drivers (turbines), extra steam demand can be generated, allowing the boiler firing rates to be increased. However, there isn't normally a lot of room to increase consumption in this manner. Second, the amount of steam imported from Foster Wheeler can be minimized, which will increase the boiler firing rates. Lastly, it is occasionally possible to export more fuel gas to Foster Wheeler if their operating conditions allow them to receive it (e.g. if they can accept more fuel gas and still meet their permit limits). Foster Wheeler often receives between 0-10 MMSCFD of gas.

Attachment 2

Manufacturer's Recommended Compressor Repair & Maintenance

Section 3
TROUBLESHOOTING

3-1 Locating Troubles

Nash vacuum pumps and compressors require little attention other than checking the ability of the unit to obtain full volume or maintain constant vacuum. If a V-belt drive is used, V-belt tension should be checked periodically and the V-belt should be inspected for excessive wear. V-belts are normally rated for service lives of 24,000 hours. If operating difficulties arise, make the following checks:

a. Check for proper seal water flow rate as specified in Paragraph 2-2.

b. Check for the correct direction of the pump shaft rotation as cast on the body of the pump.

c. Check that the unit operates at the correct rpm-not necessarily the test rpm stamped on the pump name plates. (Refer to Paragraph 2-5, step g.)

d. Check for a restriction in the gas inlet line.

e. If the pump is shut down because of a change in temperature, noise/vibration from normal operating conditions, check bearing lubrication, bearing condition, and coupling or V-belt drive alignment. Refer to Bulletin No. 642, Installation Instructions, Nash Vacuum Pumps and Compressors, for alignment procedures and V-belt tensioning.

Note

If the trouble is not located through these checks, **call your Nash Representative** before dismantling or dissembling the pump. He will assist in locating and correcting the trouble.

Section 4
PREVENTIVE MAINTENANCE

4-1 Periodic Maintenance

Note

The following schedules should be modified as necessary for your specific operating conditions.

4-2 Six-Month Intervals

a. If the drive coupling is lubricated, it should be filled with oil or grease in accordance with the coupling manufacturer's guide.

b. Check the pump bearings and lubricate as specified in Paragraph 4-4.

c. Relubricate the drive motor bearings according to the motor manufacturer's instructions.

4-3 Twelve-Month Intervals

a. Inspect the pump bearings and lubricate as specified in Paragraph 4-4.

b. Replace the stuffing box packing as specified in Paragraph 4-5.

4-4 Bearing Lubrication

Bearings are lubricated before shipment and require no lubrication for approximately six months. To check condition and quantity of grease in the bearing bracket proceed as follows:

Note

Lubricate the bearings every year, unless the pump is being operated in a corrosive atmosphere or with a liquid compressant other than water, in which case the interval should be shortened. Lubrication should be done while the pump is running.

a. Check condition of grease in bearing caps for contamination or presence of water.

b. If grease is contaminated, remove fixed or floating bearing bracket (109 or 108), fixed or floating bearing (120 or 119) and associated parts as specified in Paragraph 5-2, steps a thru r for fixed bearing (120), or Paragraph 5-3, steps a thru l for floating bearing (119). Discard bearing.

c. Flush bearing bracket and bearing cap to remove all grease.

d. Install bearing bracket, bearing and associated parts as specified in Paragraph 5-17 and as follows:

   1. For floating bearing (119), perform steps a, c, and d, Paragraph 5-17, and steps b thru m, in Paragraph 5-18. Use associated parts.

Note

Make certain that new lip seal (5-1) is seated in floating bearing outer cap (115) with sealing lip away from bearing.

2. Install new lip seal (5-1) and secure floating bearing outer cap (115) and new gasket (115-3) to floating bearing bracket (108) as specified in Paragraph 5-20, steps m thru p.

3. Rotate shaft (111) by hand and make sure there is no rubbing or metal-to-metal contact.

4. For fixed bearing (120), perform steps a, c, and d, Paragraph 5-17; and steps a thru n, Paragraph 5-18.

CAUTION

THICKNESS OF SHIMS (4) EQUAL TO THICKNESS OF SHIMS REMOVED FROM PUMP MUST BE REINSTALLED TO MAINTAIN REQUIRED END TRAVEL.

5. Install shims (4) and fixed bearing outer cap (117) on fixed bearing bracket (109) as specified in Paragraph 5-20, steps j and k.

6. Rotate shaft by hand and make sure there is no rubbing or metal-to-metal contact.

4-5 Stuffing Box Packing

A preventive maintenance schedule should be established for the tightening and replacement of the packing in the stuffing boxes of the pump. The packing in the stuffing boxes in pumps used in continuous process systems should be replaced at annual shutdown. More frequent replacement may be required on severe process applications in which liquid compressant in the pump is contaminated by foreign material. (The packing material consists of four rings with the dimensions listed in Table 5-1.)

When replacing the packing in a stuffing box, remove the old packing as follows:

Note

Record position and number of packing rings on each side of lantern gland. This information is used to make certain that lantern gland is correctly aligned.

a. Slide slinger (3) against bearing inner cap (116 or 118).

b. Loosen and remove gland nuts (101-1 or 102-1, Figure 4-3) from studs.

Table 4-1. General Grease Specifications

GENERAL REQUIREMENTS:

A. *Premium quality* industrial bearing grease.

B. *Consistency grade:* NLGI #2

C. *Oil viscosity (minimum):*
   @ 100° (38°C) - 500 SSU (100 cSt)
   @ 210° (99°C) - 58 SSU (10 cSt)

D. *Thickener (Base):* Lithium, Lithium Complex or Polyurea for optimum WATER RESISTANCE.

E. *Performance characteristics at operating temperature:*
   1. Operating temperature range; at least 0° to 250°F (18° to 121°C)
   2. "Long-Life" performance
   3. Good mechanical and chemical stability.

F. *Additives — Mandatory:*
   1. Oxidation inhibitors
   2. Rust inhibitors

G. *Additives — Optional:*
   1. Anti-wear agents
   2. Corrosion inhibitors
   3. Metal deactivators

H. *Additives — Objectionable:*
   1. Extreme Pressure (EP)* agents
   2. Molybdenum disulfide (MoS_2)
   3. Tackiness agents

*Some greases exhibit EP characteristics without the use of EP additives. These EP characteristics are not objectionable.

NASH STANDARD GREASE RECOMMENDATIONS (By Manufacturer):

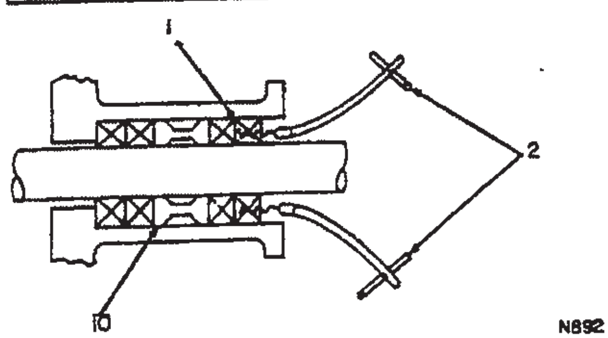
The following is a list of some greases that exhibit the desired characteristics required by Nash.

Grease Manufacturer	*Product*
AMOCO	Rykon Premium 2
Atlantic Richfield (ARCO)	ARCO Multipurpose
Chevron Oil	Chevron SRI-2
Exxon	Unirex N2
Gulf Oil	Gulfcrown No. 2
Mobil	Mobilux 2
Shell Oil	Alvania 2 or Dolium R
Texaco	Premium RB #2

*Nash Standard grease.

NOTE: This list is not an endorsement of these products and is to be used only for reference. A customer can have his local lubricant supplier cross reference these greases for an equivalent or current grease so long as it meets the General Requirements.

Grease Compatibility Note: The above listed greases are compatible with Nash Standard grease, Chevron SRI-2. To maximize a grease lubricant's performance, however, it is recommended that intermixing of different greases be kept to a minimum.



1. Packing Ring
2. Packing Pullers
10. Lantern Gland

Figure 4-1. Removing Stuffing Box Packing

Attachment 3

Main Flare System Process Flow and Vessel Diagrams

Public Version – Confidential Information Redacted

Attachment 3A

50 Unit Flare System Process Flow and Vessel Diagrams

Public Version – Confidential Information Redacted

Attachment 4

ARU Flare Process Flow and Vessel Diagrams

Public Version – Confidential Information Redacted

Attachment 5

Reductions Previously Realized – Causal Analyses Actions

Public Version – Confidential Information Redacted

Attachment 6

Planned Reductions Table

Public Version –
Confidential Information Redacted

Attachment 7

Causal Analyses –
Open Action Items

Public Version –
Confidential Information Redacted

Attachment 8

Main Flare Gas
Recovery System Diagram

Public Version –
Confidential Information Redacted

Attachment 9

Cost Effectiveness Calculations

Hydrocarbon Cost/Benefit Analysis for Flare Minimization

FINAL

Basis is BAAQMD Guidelines for calculation of cost-effectiveness for BACT
using the "levelized cash flow method"
Input parameters are in blue text

Cost Effectiveness = (Annualized Cost of Abatement System ($/yr)) /
(Reduction in Annual Pollutant Emissions (ton/yr))

Reduction in Annual Pollutant Emissions =
Baseline Uncontrolled Emissions
- Control Option Emissions

Baseline Uncontrolled Emissions:

0.8	MM scf/d flared gas
292	MM scf/yr flared gas
0.009324	lb non-methane hydrocarbon (POC) to flare / scf flared gas
98	% destruction of hydrocarbon in flare
0.000186	lb non-methane hydrocarbon (POC) emitted / scf flared gas
54,455	lb/yr non-methane hydrocarbon emissions prior to control
27.23	ton/yr

Control Option Emissions:

118	MM scf/yr additional flare gas captured
174	MM scf/yr flared gas after controls
32,449	lb/yr non-methane hydrocarbon emissions following control
16.22	ton/yr

Reduction in Annual Pollutant Emissions =

22,006	lb/yr non-methane hydrocarbon emissions (POC)
11.00	tons/yr

Total Capital Cost $10,600,000

CRF = Capital Recovery Factor (to annualize capital cost)

CRF = $[i (1 + i)^n] / [(1 + i)^n - 1]$

i = interest rate, at 0.06

n = lifetime of abatement system, at 10 yrs

CRF = 0.1359

Utilities

Power

400	bhp for flare gas compressor
0.85	efficiency at design
351.1	kw
0.10	$/kw
8,760	operating hours per year
$307,528	/yr

Annual Costs =
Direct Costs + Indirect Costs

Direct Costs		$/year
Labor	2 % of capital cost	212,000
Raw Materials		0
Replacement Parts at	2 % of capital cost	212,000
Utilities (power)		307,528
Total		$731,528

Indirect Costs		$/year
Overhead at	80 % of Labor costs	169,600
Property Tax at	1 % of Total Capital Cost	106,000
Insurance at	1 % of Total Capital Cost	106,000
General and Admin. at	2 % of Total Capital Cost	212,000
Capital Recovery at CRF x Total Capital Cost		1,440,200
Total		$2,033,800

Annualized Cost of Abatement System = $2,765,000

Cost Effectiveness =	$251,000 per ton
Typical hurdle used for BACT analysis is $17,500/ton	

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Nox Cost/Benefit Analysis for Flare Minimization

FINAL

Basis is BAAQMD Guidelines for calculation of cost-effectiveness for BACT
using the "levelized cash flow method"
Input parameters are in blue text

Cost Effectiveness = (Annualized Cost of Abatement System (\$/yr)) /
(Reduction in Annual Pollutant Emissions (ton/yr))

Reduction in Annual Pollutant Emissions =
Baseline Uncontrolled Emissions
- Control Option Emissions

Flarre gas average BTU
732 BTU/scf
0.068 lb NOx/MMBtu

Baseline Uncontrolled Emissions:

0.8	MM scf/d flared gas
292	MM scf/yr flared gas
0.0000498	lb NOx / scf flare gas
0	% destruction of NOx in flare
0.0000498	lb NOx emitted / scf flared gas
14,535	lb/yr NOx emissions prior to control
7.27	ton/yr

Control Option Emissions:

118	MM scf/yr additional flare gas captured
174	MM scf/yr flared gas after controls
8,661	lb/yr NOx emissions following control
4.33	ton/yr

Reduction in Annual Pollutant Emissions =

5,874	lb/yr NOx emissions
2.94	tons/yr

Total Capital Cost $10,600,000

CRF = Capital Recovery Factor (to annualize capital cost)
CRF = $[i\,(1 + i)^n] / [(1 + i)^n - 1]$
i = interest rate, at 0.06
n = lifetime of abatement system, at 10 yrs
CRF = 0.1359

Utilities

Power

400	bhp for flare gas compressor
0.85	efficiency at design
351.1	kw
0.10	$/kw
8,760	operating hours per year
$307,528	/yr

Annual Costs =
Direct Costs + Indirect Costs

Direct Costs		$/year
Labor	2 % of capital cost	212,000
Raw Materials		0
Replacement Parts at	2 % of capital cost	212,000
Utilities (power)		307,528
Total		$731,528

Indirect Costs		$/year
Overhead at	80 % of Labor costs	169,600
Property Tax at	1 % of Total Capital Cost	106,000
Insurance at	1 % of Total Capital Cost	106,000
General and Admin. at	2 % of Total Capital Cost	212,000
Capital Recovery at CRF x Total Capital Cost		1,440,200
Total		$2,033,800

Annualized Cost of Abatement System = $2,765,000

Cost Effectiveness =	$942,000 per ton
Typical hurdle used for BACT analysis is $17,500/ton	

Attorney Client Privileged Communication

CO Cost/Benefit Analysis for Flare Minimization

FINAL

Basis is BAAQMD Guidelines for calculation of cost-effectiveness for BACT
using the "levelized cash flow method"
Input parameters are in blue text

Cost Effectiveness = (Annualized Cost of Abatement System ($/yr)) /
(Reduction in Annual Pollutant Emissions (ton/yr))

Reduction in Annual Pollutant Emissions =
Baseline Uncontrolled Emissions
- Control Option Emissions

Flarre gas average BTU
732 BTU/scf
0.37 lb CO/MMBtu

Baseline Uncontrolled Emissions:
0.8 MM scf/d flared gas
292 MM scf/yr flared gas
0.0002708 lb CO / scf flare gas
0 % destruction of CO in flare
0.0002708 lb CO emitted / scf flared gas
79,085 lb/yr CO emissions prior to control
39.54 ton/yr

Control Option Emissions:
118 MM scf/yr additional flare gas captured
174 MM scf/yr flared gas after controls
47,126 lb/yr CO emissions following control
23.56 ton/yr

Reduction in Annual Pollutant Emissions =
31,959 lb/yr CO emissions
15.98 tons/yr

Total Capital Cost $10,600,000
CRF = Capital Recovery Factor (to annualize capital cost)
CRF = $[i (1 + i)^n] / [(1 + i)^n - 1]$
i = interest rate, at 0.06
n = lifetime of abatement system, at 10 yrs
CRF = 0.1359

Utilities
Power
400 bhp for flare gas compressor
0.85 efficiency at design
351.1 kw
0.10 $/kw
8,760 operating hours per year
$307,528 /yr

Annual Costs =
Direct Costs + Indirect Costs

Direct Costs		$/year
Labor	2 % of capital cost	212,000
Raw Materials		0
Replacement Parts at	2 % of capital cost	212,000
Utilities (power)		307,528
Total		$731,528

Indirect Costs		$/year
Overhead at	80 % of Labor costs	169,600
Property Tax at	1 % of Total Capital Cost	106,000
Insurance at	1 % of Total Capital Cost	106,000
General and Admin. at	2 % of Total Capital Cost	212,000
Capital Recovery at CRF x Total Capital Cost		1,440,200
Total		$2,033,800

Annualized Cost of Abatement System = $2,765,000

Cost Effectiveness =	$173,000 per ton
Typical hurdle used for BACT analysis is $17,500/ton	

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PM Cost/Benefit Analysis for Flare Minimization

FINAL

Basis is BAAQMD Guidelines for calculation of cost-effectiveness for BACT
using the "levelized cash flow method"
Input parameters are in blue text

Cost Effectiveness = (Annualized Cost of Abatement System ($/yr)) /
(Reduction in Annual Pollutant Emissions (ton/yr))

Reduction in Annual Pollutant Emissions =
Baseline Uncontrolled Emissions
- Control Option Emissions

Flarre gas average BTU
732 BTU/scf
0.1 lb PM/MMBtu

Baseline Uncontrolled Emissions:

0.8	MM scf/d flared gas
292	MM scf/yr flared gas
0.0000732	lb PM / scf flare gas
0	% destruction of PM in flare
0.0000732	lb PM emitted / scf flared gas
21,374	lb/yr PM emissions prior to control
10.69	ton/yr

Control Option Emissions:

118	MM scf/yr additional flare gas captured
174	MM scf/yr flared gas after controls
12,737	lb/yr PM emissions following control
6.37	ton/yr

Reduction in Annual Pollutant Emissions =

8,638	lb/yr PM emissions
4.32	tons/yr

Total Capital Cost $10,600,000

CRF = Capital Recovery Factor (to annualize capital cost)

CRF = $[i\,(1+i)^n]/[(1+i)^n - 1]$

i = interest rate, at 0.06

n = lifetime of abatement system, at 10 yrs

CRF = 0.1359

Utilities

Power

400	bhp for flare gas compressor
0.85	efficiency at design
351.1	kw
0.10	$/kw
8,760	operating hours per year
$307,528	/yr

Annual Costs =
Direct Costs + Indirect Costs

Direct Costs		$/year
Labor	2 % of capital cost	212,000
Raw Materials		0
Replacement Parts at	2 % of capital cost	212,000
Utilities (power)		307,528
Total		$731,528

Indirect Costs		$/year
Overhead at	80 % of Labor costs	169,600
Property Tax at	1 % of Total Capital Cost	106,000
Insurance at	1 % of Total Capital Cost	106,000
General and Admin. at	2 % of Total Capital Cost	212,000
Capital Recovery at CRF x Total Capital Cost		1,440,200
Total		$2,033,800

Annualized Cost of Abatement System = $2,765,000

Cost Effectiveness =	$640,000 per ton
Typical hurdle used for BACT analysis is $17,500/ton	

Attorney Client Privileged Communication

SO2 Cost/Benefit Analysis for Flare Mininimization

Year	SO2 (tons/year)
2012	48
2013	62
2014	370
2015	69
2016 YTD	22
Average for 2012 - 2015 (Baseline Emissions)	137
Control Option Emissions	27
Reduction in Emissions	110

This number is still conservatively high since there are instances that no matter how much extra flare gas compressor capacity, we would not recover the gases, such as power outages, higher flow events, and loss of 5 Gas Plant compressors or Flare Gas Recovery Compressors.

Assumes 80% reduction due to above instances

In $millions

	2006	2016
Compressor Cost Two 5.5 MMSCFD Comp	15	
Amine Treater Cost	7	
Piping	4.4	
Total Capital Cost	26.4	30.9936
2006 to 2016 Inflation (%)	17.4	

CRF = Capital Recovery Factor (to annualize capital cost)

CRF = $[i(1+i)^n]/[(1+i)^n-1]$

i = interest rate at		0.06	
n = lifetime of abatement system		10	years
CRF =		0.1359	
Utilities	$/Year	363,940.00	

Annual Costs = Direct Costs + Indirect Costs

Direct Costs	$/Year	
Labor	619872	2% of capital cost
Replacement Parts	619872	2% of capital cost
Utilities	363940	(400 bhp for flare compressor, 0.85 efficiency at design, 8760 operating hours per year)
	$ 1,603,684	

Indirect Costs	
Overhead at 80% of Labor Costs	495898
Property Tax at 1% of Total Capital	309936
Insurance at 1% of Total Capital	309936
General & Admin at 2% of Total Cap	619872
Capital Recovery at CRF x Total Cap	4211037
	$ 5,946,679

Annualized Cost of Abatement System $ 7,550,363

Cost Effectiveness for SO2 = $ 68,715 per ton

based on annualized emissions and annualized cost

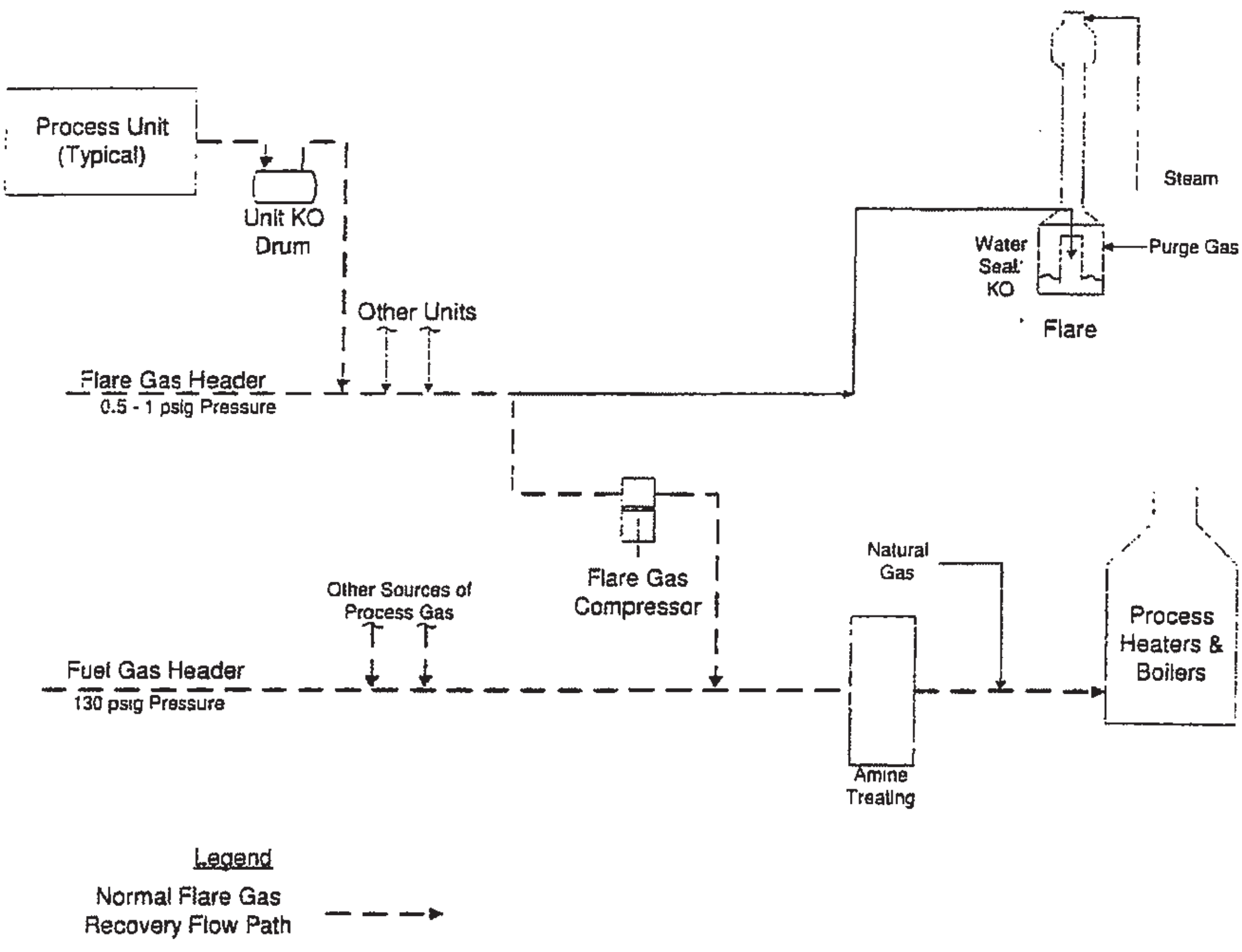
Cost Effectiveness hurdle for BACT analysis is $18,200 / ton SO2

Attorney Client Privileged Communication

Attachment 10

Typical Flare Gas Recovery System Diagram

Typical Flare Gas Recovery System

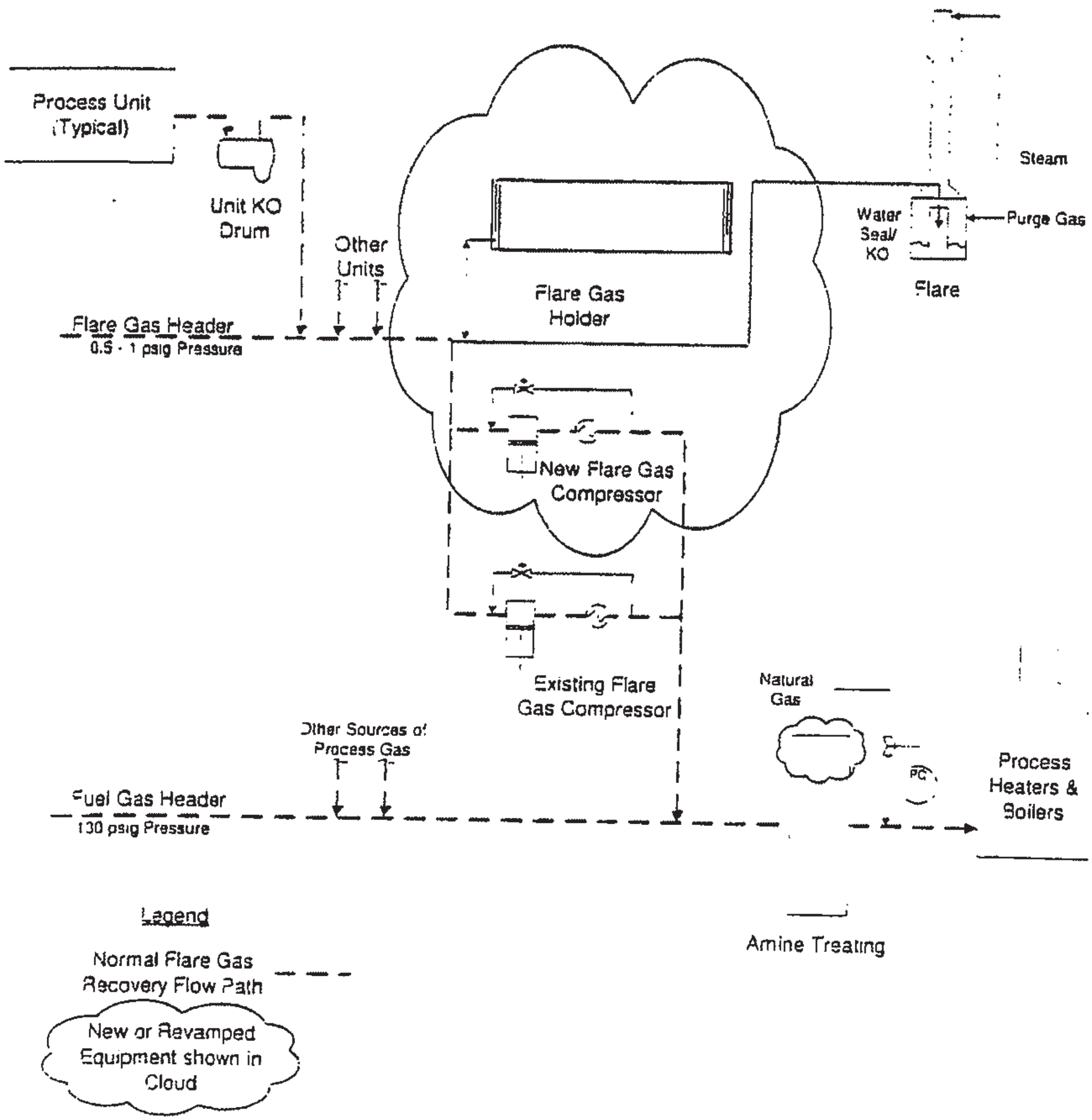


May 30, 2006

Attachment 11

Flare Gas Recovery with Gas Holder Diagram

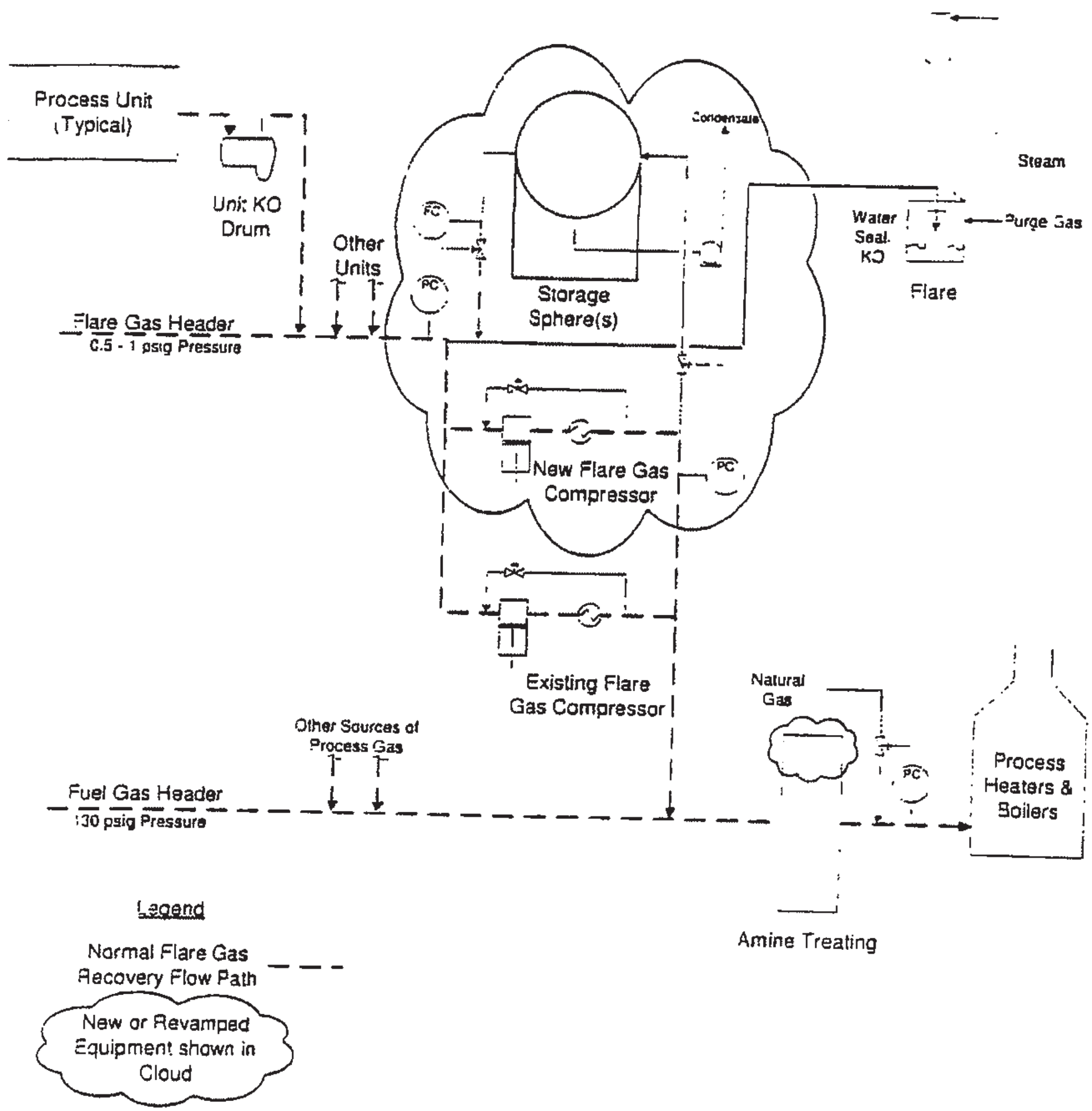
Flare Gas Recovery With Gas Holder



Attachment 12

Flare Gas Recovery with Gas Storage Diagram

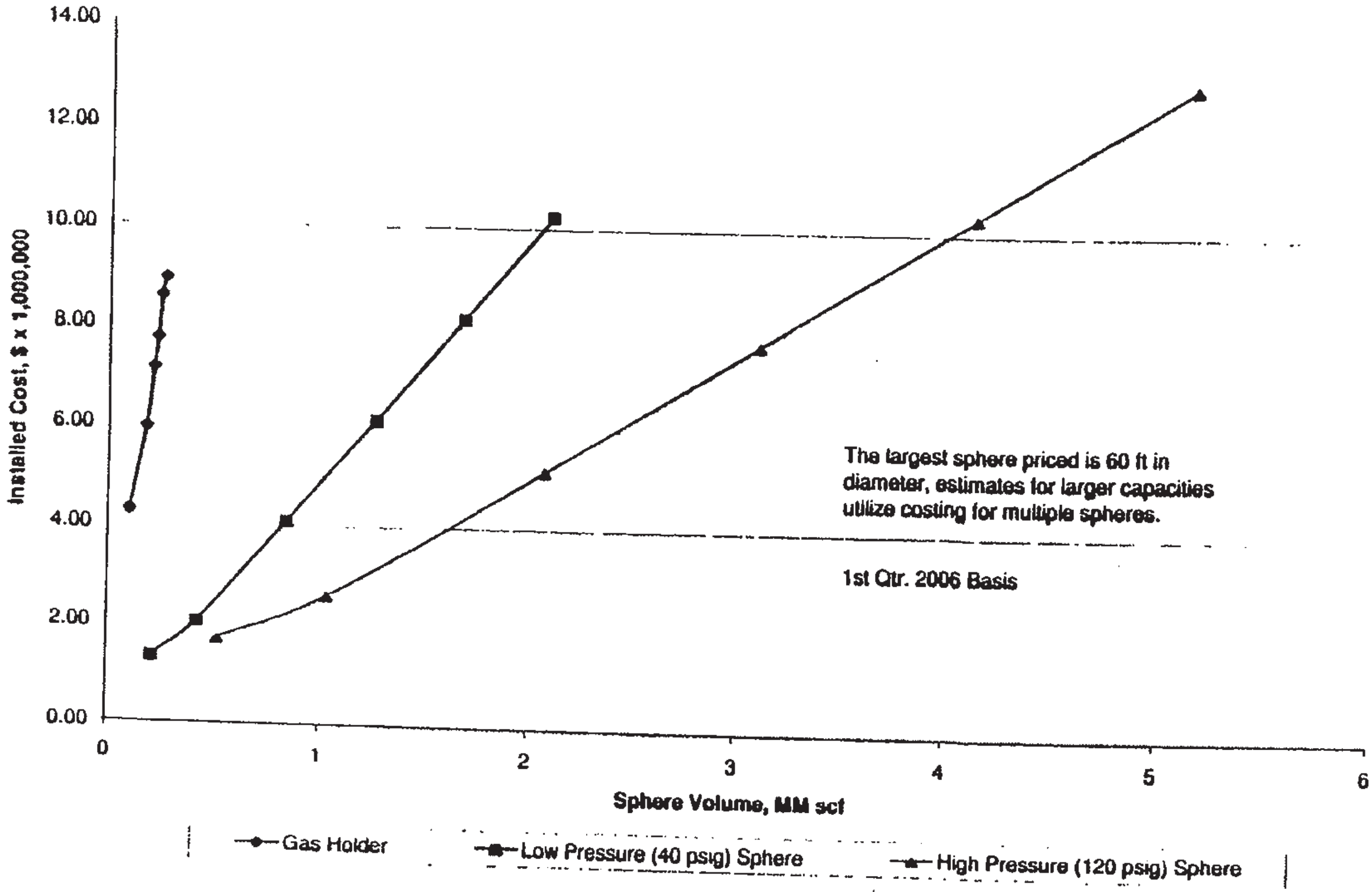
Flare Gas Recovery With Storage Sphere



Attachment 13

Vessel Cost Curve

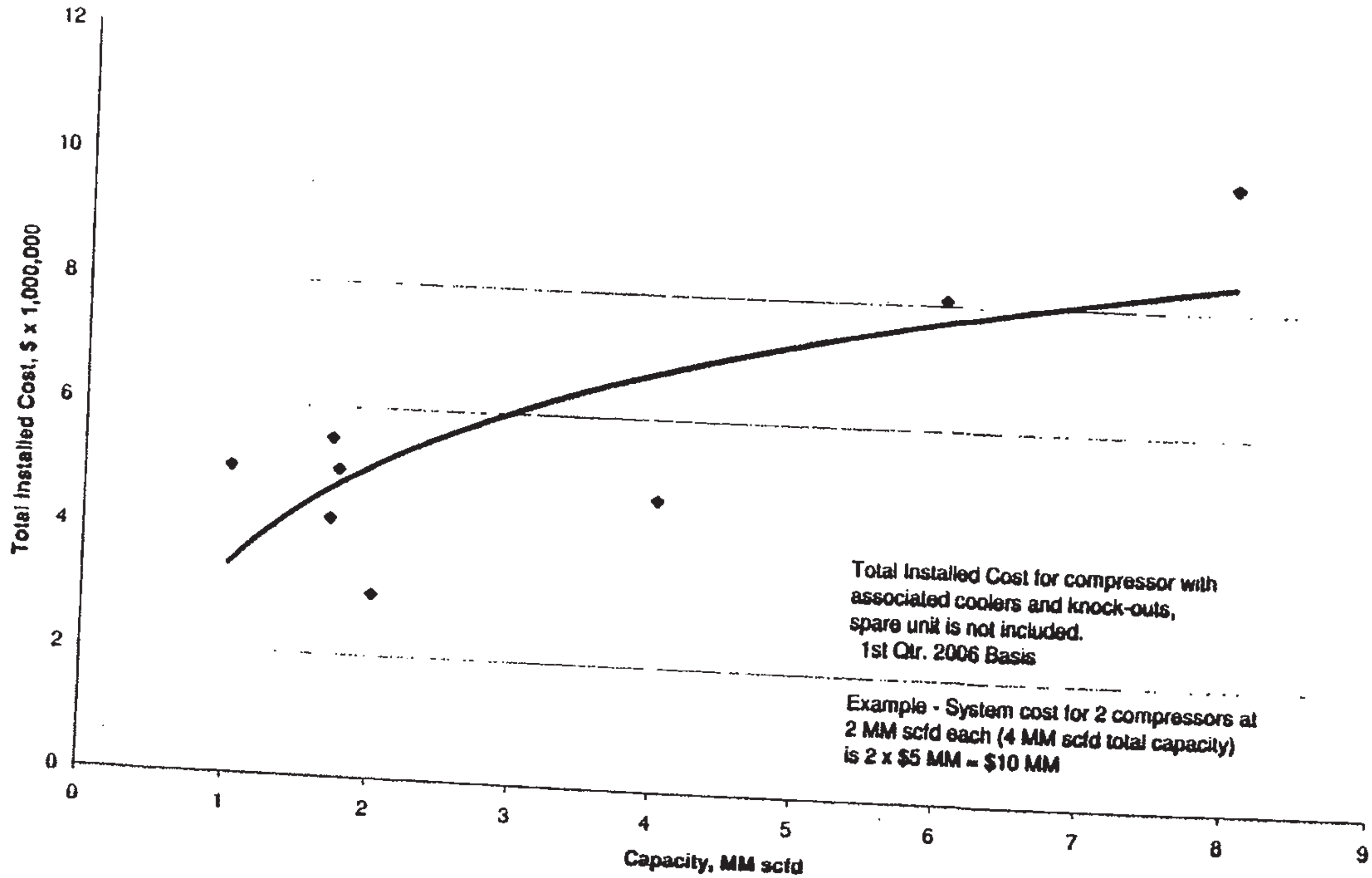
Flare Gas Storage Options



Attachment 14

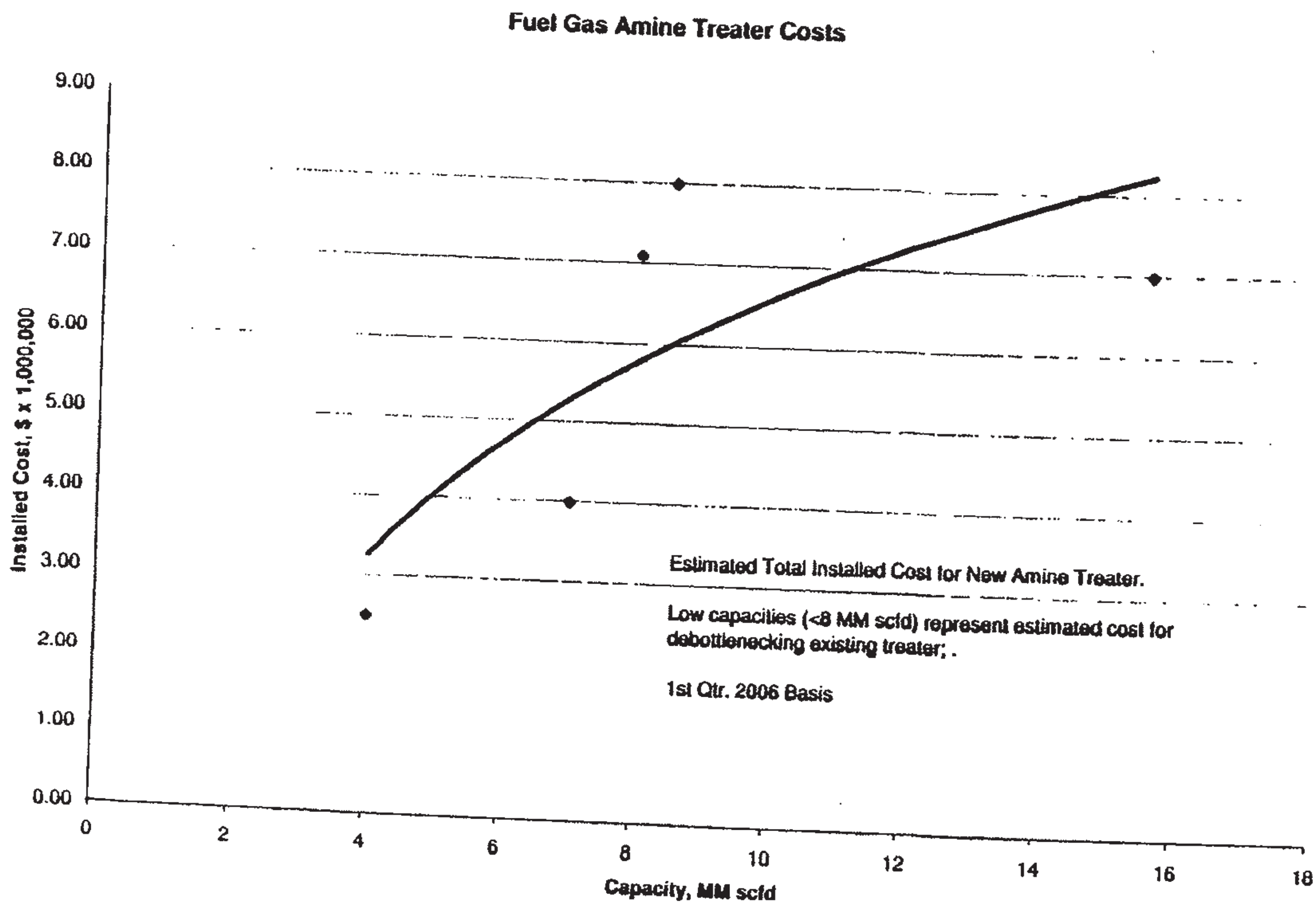
Compressor Cost Curve

Flare Gas Compressor System Costs



Attachment 15

Gas Treatment Cost Curve



Confidential Attorney-Client Privileged Document

Attachment 16

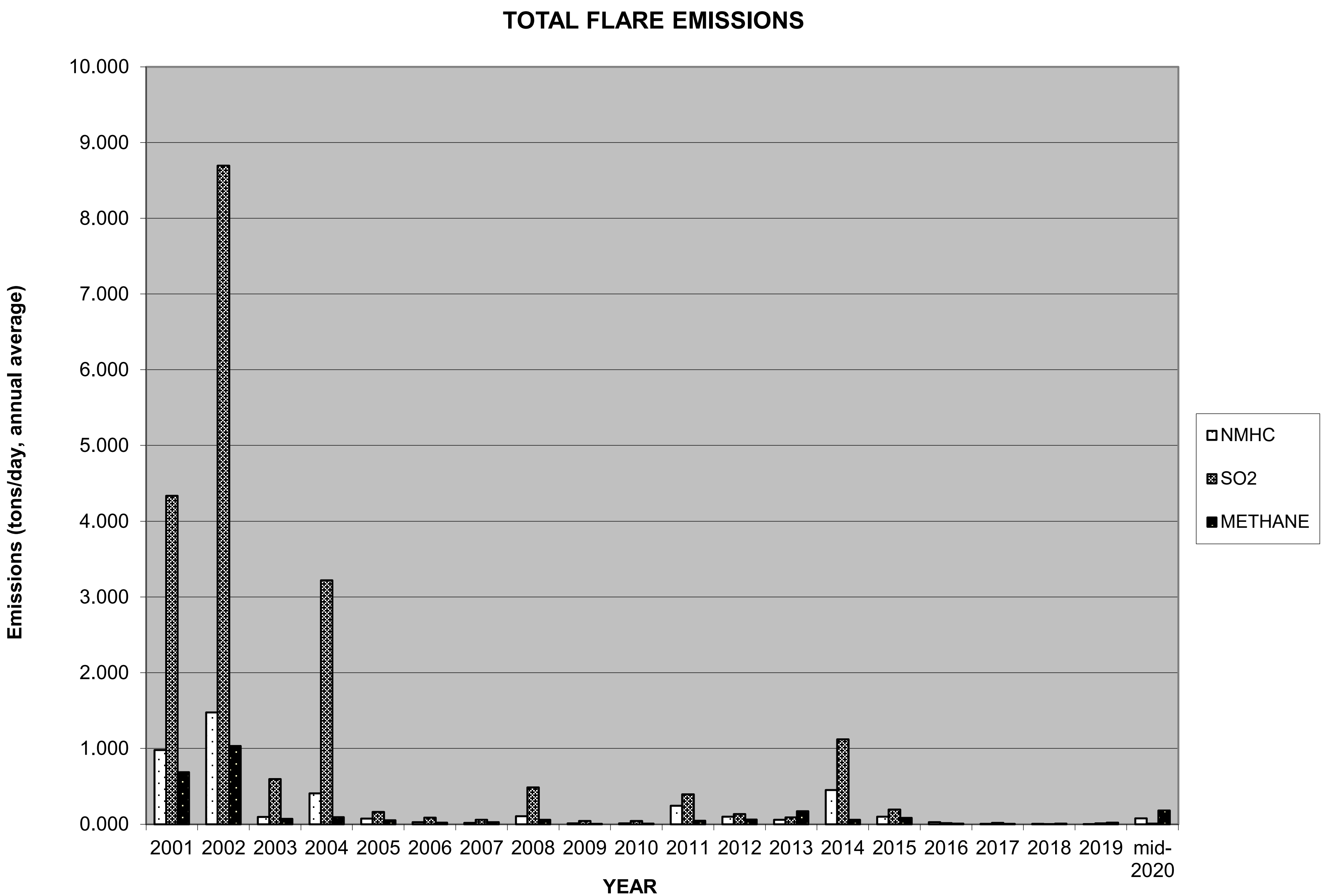
Small Flare Events
Action List

Public Version
Confidential Information Redacted

Attachment 17

Executive Summary Graphs

Marathon's Tesoro Martinez Refinery
Flare Minimization Plan - 2020 Update



Marathon's Tesoro Martinez Refinery
Flare Minimization Plan - 2020 Update