Supplemental Technical Comments of Communities for a Better Environment ('CBE')

Regarding the

Valero Benicia Crude by Rail Project ('project') Draft Environmental Impact Report ('DEIR') Use Permit App. 12PLN-00063 SCH #2013052074

By Greg Karras,* Senior Scientist
15 September 2014

Major findings documented by these comments

The project would introduce a new refinery fire and explosion hazard that the DEIR does not identify.	comments 1–5	pages 4–5
The DEIR's description of the project's effects on crude oil transport is unsupported and incorrect.	comments 6–14	pages 6–10
A significant potential impact of the project on local air quality is not identified or addressed by the DEIR.	comments 15–17	pages 10–11
A significant potential impact of the project on climate protection is not identified or addressed by the DEIR.	comments 18–20	pages 11–12
The DEIR's conclusion that the project *could not* lead to processing Canadian 'tar sands' oil at this refinery in substantial amounts is unsupported and incorrect.	comments 21–27	pages 12–15
The DEIR's conclusion that the project's crude switch *would not* increase emissions from existing and permitted refinery equipment is unsupported and incorrect.	Comments 28–35	Pages 15–18
Publicly available information on current conditions that is needed to evaluate the change in oil feedstock enabled by the project and its resultant impacts is erroneously labeled 'secret' and omitted by the DEIR.	comments 36–40	Pages 18–24

***Qualifications:** I, Greg Karras, am employed as a Senior Scientist for Communities for a Better Environment (CBE). My duties for CBE include technical research, analysis, and review of information regarding industrial health and safety investigation, pollution

prevention engineering, pollutant releases into the environment, and potential effects of environmental pollutant accumulation and exposure.

My qualifications for this opinion include extensive experience, knowledge, and expertise gained from 30 years of industrial and environmental health and safety investigation in the energy manufacturing sector, including petroleum refining, and in particular, petroleum refineries in the San Francisco Bay Area.

Among other assignments, I served as an expert for CBE and other non-profit groups in efforts to prevent pollution from oil refineries, to assess environmental health and safety impacts at refineries, to investigate alternatives to fossil fuel energy, and to improve environmental monitoring of dioxins and mercury. I served as an expert for CBE in collaboration with the City and County of San Francisco and local groups in efforts to replace electric power plant technology with reliable, least-impact alternatives. My work as an expert for CBE and other non-profit groups in a 2007–2008 review of the proposed Chevron Richmond refinery 'Hydrogen Renewal Project' was cited by the Appeals Court in support of CBE's subsequent successful advocacy regarding that proposed project (*See CBE v. City of Richmond* 184 Cal_Ap.4th).

I serve as an expert for CBE and other groups participating in environmental impact reviews of related refinery projects, including, among others, the "Contra Costa Pipeline Project," "Phillips 66 Propane Recovery Project," and "Shell Greenhouse Gas Reduction Project" now pending before the County of Contra Costa, the "Phillips 66 Company Rail Spur Extension Project" now pending before the County of San Luis Obispo, and the "Chevron Richmond Refinery Modernization Project," now pending before the Bay Area Air Quality Management District and the Superior Court.

As part of CBE's collaboration with the refinery workers' union, United Steelworkers (USW), community-based organizations, the Labor Occupational Health Program at UC Berkeley, and environmental groups, I serve as an expert on environmental health and safety concerns shared by refinery workers and residents regionally. In this role I serve as CBE's representative in the Refinery Action Collaborative of Northern California, and as an expert for CBE and other groups in the development of a refinery emissions control rule to be considered for adoption by the Bay Area Air Quality Management District. Separately, I serve as an expert for the Natural Resources Defense Council in ongoing research on the effects of changes in oil feedstock quality on refinery air emission rates.

I authored a technical paper on the first publicly verified pollution prevention audit of a U.S. oil refinery in 1989 and the first comprehensive analysis of regional oil refinery selenium discharge trends in 1994. From 1992–1994 I authored a series of technical

analyses and reports that supported the successful achievement of cost-effective pollution prevention measures at 110 industrial facilities in Santa Clara County. I authored the first comprehensive, peer-reviewed dioxin pollution prevention inventory for the San Francisco Bay, which was published by the American Chemical Society and Oxford University Press in 2001. I authored an alternative energy blueprint, published in 2001, that served as a basis for the Electricity Resource Plan adopted by the City and County of San Francisco in 2002. In 2005 and 2007 I co-authored two technical reports that documented air quality impacts from flaring by San Francisco Bay Area refineries, and identified feasible measures to prevent these impacts.

My recent publications include the first peer reviewed estimate of combustion emissions from refining denser, more contaminated "lower quality" crude oils based on data from U.S. refineries in actual operation, which was published by the American Chemical Society in the journal *Environmental Science & Technology* in 2010, and a follow up study that extended this work with a focus on California and Bay Area refineries, which was peer reviewed and published by the Union of Concerned Scientists in 2011. Most recently, I presented invited testimony regarding *inherently safer systems* requirements for existing refineries that change crude feedstock at the U.S. Chemical Safety Board's 19 April 2013 public hearing on the Chevron Richmond refinery fire.

My curriculum vitae and publications list are appended hereto.

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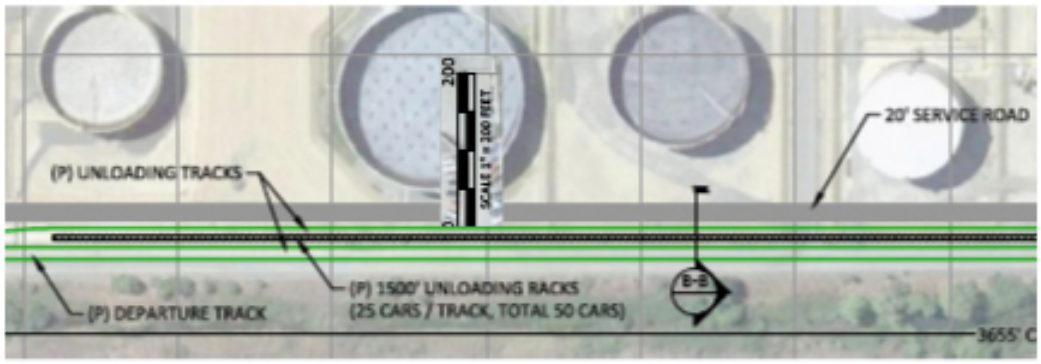
Communities for a Better Environment (CBE)
September 15, 2014

1. The proximity of proposed rail activities to flammable or explosive hazardous materials in the existing refinery is not quantified or discussed in the DEIR.
For example, the excerpt from DEIR Figure 3-3 reproduced in Map 1 below suggests that the new crude unloading could occur very close to existing hydrocarbon storage in the refinery's "lower tank farm." The scale key from Figure 3-3, superimposed on the largest tank shown in Map 1, suggests that several tanks would be less and 150 feet from the proposed crude unloading operation, and at least one tank would be within 50 feet. Despite presenting this apparently to-scale image (Figure 3-3), however, the DEIR does not quantify distances to these existing storage tanks numerically, and its text does not appear to discuss the proximity to existing refinery hazards, except to say that a spill containment berm for the tanks would be relocated to make room for the project.



Map 1. Storage tanks close to proposed crude-by-rail unloading rack.
Excerpt from DEIR Figure 3-3 (200' grid-scale indicator repositioned for reference).

2. The types and amounts of hazardous materials that could be present in the refinery near the proposed rail activities are not disclosed in the DEIR. The visual data provided in its Figure 3-3, though inadequate for full analysis of potential hazards, do, however, show that large quantities of potentially flammable or explosive hydrocarbons could be present very near to the proposed rail activities. For example, floating-roof tanks are clearly visible near the proposed unloading rack. (See Map 1: The crescent-shaped shadows appearing on the roofs of three tanks indicate that the tanks are not full and their roofs, which float on their contents, are thus lower than the tank rims that are casting shadows on these tank roofs.) Floating-roof tanks are typically used to store more volatile hydrocarbons, such as gasoline, as an emission reduction measure. More volatile hydrocarbons are more highly flammable and explosive. This image thus suggests that large quantities of highly flammable or explosive material would be stored near the proposed crude-by-rail operations. The DEIR, however, fails to disclose specific types, amounts, or locations of materials in the refinery near proposed project activities.

3. Potential ignition sources for fires or explosions that might occur upon loss-of-containment (spills) of hazardous materials associated with project operation are not fully disclosed by the DEIR. The DEIR acknowledges a potential for hydrocarbon release incidents, including but not limited to those from unloading operations (DEIR at 4.7-20; 4.7-21) and from nearby refinery tanks (tanks berm discussed at 3-20), and it states that locomotives would operate at the proposed loading facility (see 3-21). However, the DEIR does not identify and discuss—or, alternatively, confirm the absence of—other potential sources of ignition in or near the area of proposed project operation.

4. The likelihood, and the potentially catastrophic consequences, of refinery fires or explosions caused by ignition of hydrocarbon releases associated with project operation are not disclosed or analyzed in the DEIR. As stated, the DEIR acknowledges the potential for such releases or spills (see 4.7-20, 4.7-21). However, the hazard analysis in chapter 4.7 of the DEIR does not disclose the potential for fires or explosions resulting from ignition of such spills, does not disclose the potential for such fires to spread into other nearby refinery equipment, and does not to discuss the potential consequences of such incidents[1]—although those consequences could be catastrophic.

5. Pre-construction requirements to analyze and apply *Inherently Safer Systems* with respect to potential explosion and fire hazards of project operation in the refinery could lessen or avoid this potentially catastrophic hazard but are not disclosed, discussed, analyzed or proposed in the DEIR. *Inherently Safer* technology, design, and systems are not discussed, even in concept, in the DEIR. It does not disclose or discuss the U.S. Chemical Safety Board's authoritative findings and recommendations regarding the need to require *Inherently Safer Systems* to the greatest extent feasible, including "prior to the construction" of refinery projects.[2] It does not disclose that this need for pre-construction analysis and design of *Inherently Safer Systems (ISS)* applies to refinery hazards associated with rail loading projects, among other refinery projects.[3] The DEIR does not disclose, analyze, or propose this means to lessen or avoid this on-site explosion and fire hazard of the project, or even whether Valero conducted *ISS* analysis.

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[1] Furthermore, section 3.2.2.3 and Appendix F of the DEIR, to which its discussion of other hazards in chapter 4.7 refers, also do not disclose or discuss the potential for fires or explosions resulting from ignition of such on-site spills, the potential for such fires to spread into other nearby refinery equipment, or the potentially catastrophic consequences of such incidents.

[2] U.S. Chemical Safety and Hazard Investigation Board, 2013. *Interim Investigation Report, Chevron Richmond Refinery Fire;* adopted by the Board on 19 April 2013.

[3] See 11 July 2013 letter from Michael Dossey, Accidential Release Prevention Engineer, Contra Costa County Health Services, Hazardous Materials Programs, to Jim Ferris, Health and Safety Superintendent, Phillips 66 San Francisco Refinery, regarding: *Phillips 66 Propane Recover Project (County File #LP12-2073).*

6. The DEIR discloses no estimate of the expected duration of project operation. Accurate evaluation of a project's environmental implications requires an estimate of how long the project could operate. For example, changes in the sources of crude oils supplied to the refinery as a result of this project affect its environmental impacts,[4] and as the DEIR acknowledges (see pp. 3-13, 3-14), factors that affect which crude feedstocks are selected can change over time. A reasonably reliable estimate of project service life must be available—it would have been needed by Valero's engineers to select materials and other project design parameters for a given service life, and by its financiers to estimate the potential return on its investment before committing capital to the project. In any case, EIRs for other refinery projects have acknowledged that it was reasonable to expect that those project's equipment could operate for several decades. Despite the need for this information and its apparent availability, however, the DEIR does not appear to disclose any estimate of how long the project could operate if it is built as proposed.

7. No data or analysis is provided in the DEIR to support its assertion that the project would displace only crude oils delivered to the refinery by marine vessels. The refinery receives and processes California-produced crude via pipeline, *and* crude produced in many other parts of the world via marine vessels ("ships"). Inexplicably, however, the DEIR asserts that *only* the crude received by ship would be displaced by the proposed deliveries of crude by rail, and thus *none* of the current quantity of California-produced crude, now received by pipeline, would be displaced. (DEIR at 3-1, 3-2.) The DEIR acknowledges that the market supplying the refinery's crude feedstock is global,[5] although it does not disclose the extent of this global availability in relevant detail. For example, though this is not disclosed in the DEIR, during 2004–2014 Valero reported processing crude oils at the Benicia refinery that were received as foreign imports from countries on every continent. See Table 1. The DEIR also acknowledges that "Valero's crude feedstocks change based on new developments and conditions" affecting many factors, including but not limited to the quality and the price of *available* crude oils. (DEIR at 3-12, 3-13). Yet the DEIR presents no data or analysis regarding any of these factors that supports its 'marine vessel-displacement-only' assertion. It even appears to admit, on page 3-1, that this assertion is only an assumption about Valero's plans.[6] In any case, the DEIR asserts this unlikely scenario without any factual support.

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[4] The DEIR acknowledges this, by analyzing how changes in crude feedstocks that result in changes in crude delivery activities could affect environmental impacts, even though its analysis of such impacts is incomplete and erroneous as discussed further below.

[5] See DEIR at 3-7 (many different crude oils produced "all over the world") and 3-12 ("Valero can choose from a wide variety of crudes available in the marketplace at any given time. These crudes range from light sweet to heavy sour, with a range of options in between").

[6] The project objective to displace "up to" 70,000 b/d of ship delivery (DEIR at 3-5) commits to no such assumption: it *allows for* displacing crude received by ship, by pipeline, or both.

Table 1. Countries of origin for foreign crude imports processed from 2004–2013 at the Valero Benicia refinery indicate crude supplied from every continent.

Algeria	Colombia	Peru
Angola	Ecuador	Russia
Australia	Iraq	Saudi Arabia
Brazil	Mexico	Trinidad & Tobago
Canada	Oman	Venezuela

Source: U.S. Energy Information Administration (EIA) *Company Level Imports Archives;* downloaded 9/7/14 from www.eia.gov/petroleum/imports/companylevel/archive

8. Authoritative data demonstrating a dramatic long-term decline in California crude oil production are not disclosed, discussed, or analyzed in the DEIR. As stated, crude delivered to this refinery by pipeline is produced in California. California-produced crude, for all practical purposes, is refined exclusively in California; this is in part because it is in serious long-term decline. Based on data reported by the California Energy Commission (CEC),[7] from 1986–2013 deliveries of California-produced crude to refineries declined by 43%, from 1.10 million to 0.63 million barrels per day (b/d). The DEIR does not disclose, discuss, or analyze these data.

9. Authoritative data demonstrating a dramatic long-term decline in California crude oil reserves are not disclosed, discussed, or analyzed in the DEIR. Based on data reported by the U.S Energy Information Administration (EIA),[8] from 1989–2012 proved reserves of crude oil in California's San Joaquin Basin declined by 45%, from 3.44 billion barrels in 1989 to 1.89 billion barrels in 2012. Although crude oil delivered to the Benicia refinery via pipeline is produced primarily in the San Joaquin Valley Basin (see DEIR at 3-1), the DEIR does not disclose, discuss, or analyze these data.

10. Government and industry projections indicating that the long-term decline in California crude oil supplies will continue are not disclosed, discussed or analyzed in the DEIR. The CEC has projected that "California crude oil production is expected to continue to decline, despite higher prices and increases in drilling activity" and that by 2030, in-state crude production could dive to as low as 0.33–0.41 million b/d (120–150 million b/year).[9] See Chart 1. Industry analysts also have projected that California-produced crude will continue to decline, such that California refiners will replace it with crude from other sources. The DEIR does not disclose or discuss these projections.

[7] Data from http://energyalmanac.ca.gov/petroleum/statistics/crude_oil_receipts (dnldd. 9/7/14).
[8] Data from http://www.eia.gov/dnav/pet/pet_crd_pres_dcu_RCAJ_a.htm (dnldd. 9/8/14).
[9] *California Crude Oil Import & Infrastructure Forecast;* Ryan Eggers; CEC Transportation Committee Workshop for the 2011 IEPR, 9/9/11. See also Schremp, 5/11/11; Eggers, 8/24/09.

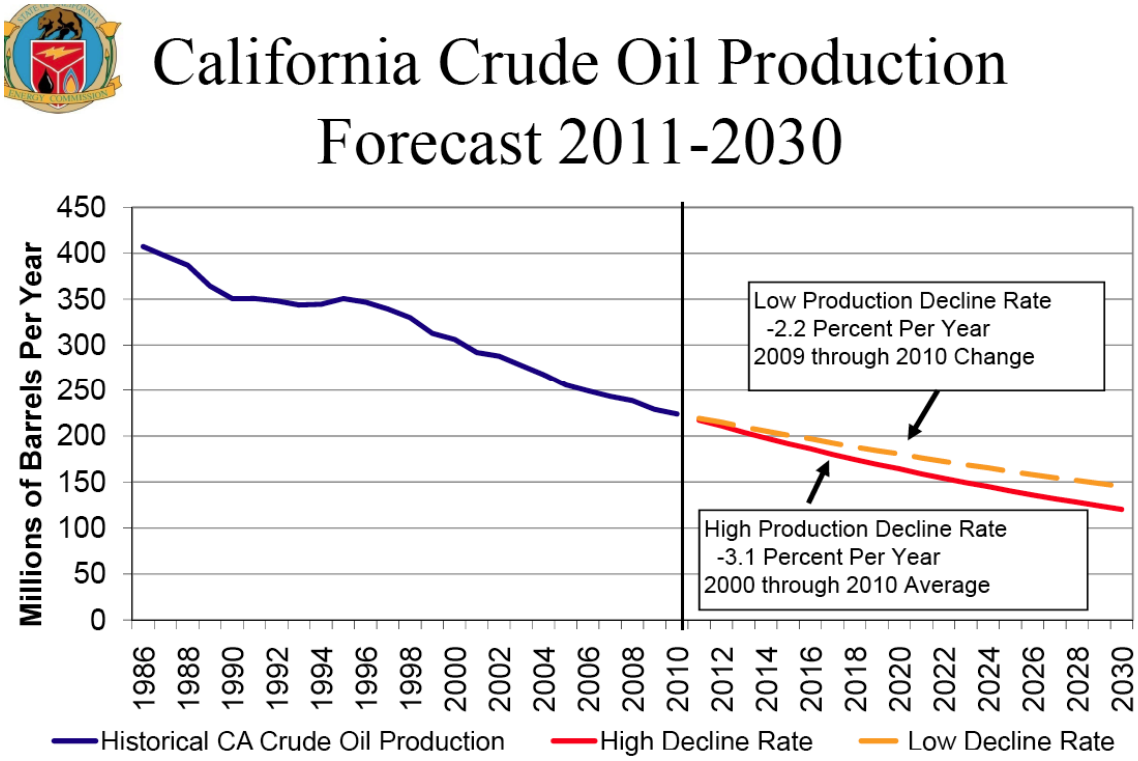

Chart 1. California Crude Oil Production Forecast; chart reproduced from CEC (2011).[9]

11. Authoritative data demonstrating a dramatic long-term increase in foreign crude oil deliveries to California refineries by ship are not disclosed, discussed, or analyzed in the DEIR. As in-state crude supplies decline the refining industry is replacing them primarily with foreign crude oils that are imported by ship. Based on data reported by the CEC, from 1986–2013 deliveries of imported foreign crude to California refineries increased by 780%, from 0.10 million to 0.88 million b/d, and foreign crude reached 51% of total statewide refinery crude inputs by 2013.[10] Nearly all of this increasing foreign supply was delivered by ship: rail deliveries, though increasing fast, accounted for only 17,251 b/d in 2013,[11] or ≈1% of statewide refinery crude inputs that year. Crude oils in the 20–36 ºAPI and 0.4–1.9 % sulfur content range that the DEIR asserts can be processed at the Benicia refinery[12] accounted for 350,000 b/d of these foreign imports in 2013.[13] The DEIR does not disclose, discuss, or analyze these data.

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[10] Data from http://energyalmanac.ca.gov/petroleum/statistics/crude_oil_receipts (dnldd. 9/8/14).
[11] Data from http://energyalmanac.ca.gov/petroleum/statistics/2013_crude_by_rail (dnldd 9/8/14).
[12] See DEIR at 3-14.
[13] Data from www.eia.gov/petroleum/imports/companylevel/archive (EIA data dnldd 9/7/14).

12. Projections of substantial continuing crude production growth in locations that already supply crude to the Benicia refinery by ship are not disclosed, discussed, or analyzed in the DEIR. For example, the Energy Resources Conservation Board of Alberta, Canada has projected that from 2012–2022 Alberta production of upgraded and nonupgraded bitumen could grow by more than 1.6 million b/d.[14] See Chart 2. Among other dispositions, these tar sands-derived oils are now delivered via pipeline and ship to California. Although the refinery has processed crude delivered to Carquinez Strait by ship from Canada,[15] the DEIR omits any reference to projections of continuing growth in the availability of crude that can be shipped to the refinery by boat.

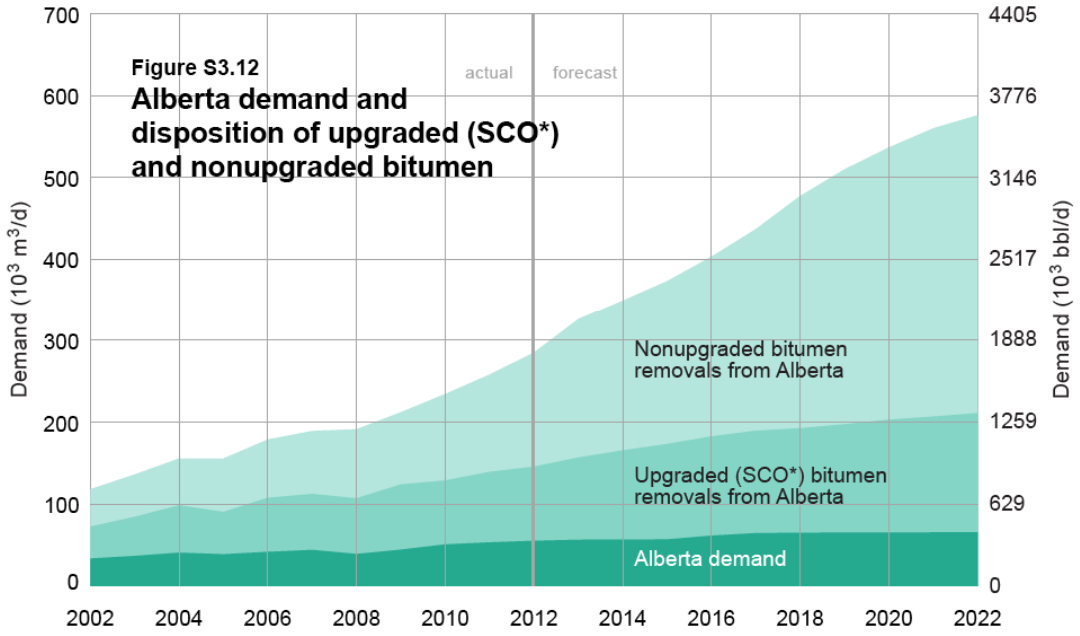

Chart 2. Actual and forecast tar sands oil exports from Alberta, Canada, 2002–2022. Chart reproduced from Alberta ERCB Publication ST98-2013.[14] *SCO: Synthetic crude oil.

13. The DEIR does not discuss pipeline delivery data, or disclose pipeline capacity data, for comparison to the project's 70,000 b/d capacity. The DEIR does not state a baseline crude input via pipeline, even though this volume can be deduced based on data it reports at page 3-2 (≈79,600 b/d at the DEIR's asserted 'baseline' plant utilization). Further, the DEIR does not include the refinery's crude pipeline capacity, although data reported publicly elsewhere[16] suggest a pipeline capacity as high as ≈240,000 b/d.

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[14] *ST98–2013: Alberta's Energy Reserves 2012 and Supply/Demand Outlook 2013–2022;* Energy Resources Conservation Board: Alberta, Canada. ISSN 1910–4235. (www.ercb.ca).
[15] Data from www.eia.gov/petroleum/imports/companylevel/archive (EIA data dnldd 9/7/14).
[16] PHMSA 000068712 Benicia Refinery Oil Spill Contingency Plan at 100-11 and Table 400-1a (20" Avon Meter–Benicia transbay crude oil line; 10,000 bph maximum allowable flow).

14. The DEIR fails to consider the extent to which the project could displace crude supplies currently delivered to the Benicia refinery by pipeline. The City could have considered the available evidence identified in comments 6–13 above in its evaluation of the project. Had it done so, the City could have concluded that during its operating life, instead of displacing only ship delivery from worldwide sources of crude, the project has the reasonable potential to displace dwindling California crude supplies that are currently delivered to the Benicia refinery via pipeline. The DEIR, however, fails to disclose or analyze this potential effect of the project.

15. The DEIR's local air quality analysis is incomplete because it relies on emission offsets that are unsupported. The DEIR's analysis of potential impacts associated with 'local' (Bay Area Air Basin) emissions of criteria air pollutants relies on purported emission reductions that it estimates directly from its estimates of marine vessel deliveries of crude that the DEIR claims project rail deliveries of crude would displace. Specifically, the DEIR's project emission estimates rely on its assertion that *only* marine vessel deliveries—and *no* pipeline deliveries—would be displaced by project rail deliveries of crude to the refinery.[17] This 'marine vessel-displacement-only' assertion is unsupported by any facts in the DEIR. (See comment 6.) Thus, the DEIR's emission estimates that rely on this assertion are not supported by factual evidence in the DEIR. Therefore, the DEIR's local air quality analysis is incomplete.

16. The DEIR underestimates the project's potential local air emissions because it overestimates the emissions it claims would be offset by displaced ship deliveries. As stated, the DEIR's assertion that *only* marine vessel deliveries—and *no* pipeline deliveries—would be displaced by project rail deliveries of crude to the refinery is not supported by any facts in the DEIR. Instead, substantial evidence that the DEIR fails to disclose or analyze shows that the project, over its operating life, will most likely displace pipeline deliveries of declining California-produced crude. (See comments 6–15 above.) This is important because displacing pipeline deliveries means that more marine vessel deliveries will continue, despite the project, and will continue to cause ship emissions that the DEIR erroneously assumes are eliminated. Thus, by incorrectly assuming that all project rail deliveries will displace marine vessel deliveries, the DEIR overestimates the project's potential to reduce marine vessel deliveries, thereby overestimating reductions in ship emissions that it claims will offset project emissions. (See DEIR at 4.1-19.) Therefore, by *overestimating* the reduction in ship emissions that it claims will offset emissions the project would cause in the Bay Area Air Basin (Id.), the DEIR *underestimates* the project's potential to increase local air emissions.

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[17] See DEIR at 4.1-19, esp. the "Marine Vessels (Displaced Baseline)" row in Table 4.1-5.

17. The DEIR fails to identify a significant potential impact on local air quality because it ignores the likelihood that the project would replace crude oil deliveries by pipeline instead of by ship. Substantial evidence supports the conclusion that instead of displacing deliveries of growing crude supplies via ship, the project has the reasonable potential to displace dwindling crude supplies currently delivered to the Benicia refinery via pipeline. (See comments 6–16.) In this likely scenario, instead of the unsupported and erroneous emission offsets that the DEIR claims by assuming *only* ship deliveries would be replaced by the project (see Table 4.1-5), the real offsets could approach zero. Without those claimed offsets, the DEIR itself estimates that the project would cause emissions of nitrogen oxides (NOx) to increase by ≈33 tons per year (t/y) in the Bay Area Air Basin. (Id.) The DEIR asserts that a NOx emission increase of more than 10 t/y would be considered a significant potential impact. (Id.) Thus, there is a reasonable potential that the project would result in a significant local air quality impact. By its failure to analyze the likelihood that the project would replace pipeline instead of ship deliveries of crude, the DEIR fails to identify this significant local air impact.

18. The DEIR's greenhouse gas analysis is incomplete because it relies on emission offsets that are unsupported. The DEIR's analysis of potential impacts associated with greenhouse gas (GHG) relies on purported emission reductions that it estimates directly from its estimates of marine vessel deliveries of crude that the DEIR claims project rail deliveries of crude would displace. Specifically, the DEIR's project emission estimates rely on its assertion that *only* ship deliveries—and *no* pipeline deliveries—would be displaced by project rail deliveries of crude to the refinery.[18] This 'marine vessel-displacement-only' assertion is unsupported by any facts in the DEIR. (See comment 6.) Thus, the DEIR's emission estimates that rely on this assertion are not supported by evidence in the DEIR. Therefore, the DEIR's GHG emissions analysis is incomplete.

19. The DEIR underestimates the project's GHG emissions because it overestimates the emissions it claims would be offset by displaced ship deliveries. As stated, the DEIR's assertion that *only* marine vessel deliveries—and *no* pipeline deliveries—would be displaced by project rail deliveries of crude to the refinery is not supported. Instead, substantial evidence that the DEIR fails to disclose or analyze shows that the project, over its operating life, will most likely displace pipeline deliveries of declining California-produced crude. (See comments 6–18 above.) This is important because displacing pipeline deliveries means that more marine vessel deliveries will continue, despite the project, and will continue to cause ship emissions that the DEIR erroneously assumes are eliminated. Thus, by incorrectly assuming that all project rail deliveries will displace marine vessel deliveries, the DEIR overestimates the project's potential to

[18] See DEIR at 4.6-12, esp. the "Marine Vessels Displaced (Baseline)" row in Table 4.6-5.

reduce marine vessel deliveries, thereby overestimating reductions in ship emissions that it claims will offset the project's GHG emissions. (See DEIR at 4.6-12.) Therefore, by *overestimating* the reduction in ship emissions that it claims will offset emissions the project would cause (Id.), the DEIR *underestimates* the project's potential to increase GHG emissions.

20. The DEIR fails to identify a significant potential climate impact because it ignores the likelihood that the project would replace crude oil deliveries by pipeline instead of by ship. Substantial evidence supports the conclusion that instead of displacing deliveries of growing crude supplies via ship, the project has the reasonable potential to displace dwindling crude supplies currently delivered to the Benicia refinery via pipeline. See comments 6–19 above. In this more likely scenario, instead of the unsupported and erroneous emission offsets that the DEIR claims by assuming *only* ship deliveries would be replaced by the project (see Table 4.6-5) the real offsets could approach zero. Without those claimed offsets, the DEIR itself estimates that the project would cause emissions of GHGs (CO_2e) to increase by ≈18,433 metric tons per year. (Id.) The DEIR asserts that a CO_2e emission increase of more than 10,000 metric tons/year would be considered a significant potential impact. (Id.) Thus, there is a reasonable potential that the project would result in a significant climate impact. By its failure to analyze the likelihood that the project would replace pipeline instead of ship deliveries of crude, the DEIR fails to identify this significant climate impact.

21. The DEIR does not disclose and evaluate data on the quality of dwindling California crude supplied to the refinery that the project could replace. The project is likely to replace California crude the refinery now receives by pipeline. (See comments 6–17.) Data on the quality of this crude stream is available. For example, the average density of California crude delivered to the Benicia refinery is in the range of 17–20 ºAPI, based on peer reviewed estimates.[19] The DEIR classifies crude oils this dense (17–20 ºAPI) as "heavy" crude. (DEIR at 3-17, Figure 3-4.) Thus, available data suggest that replacing dwindling California pipeline inputs with similar-quality crude would require the project to deliver heavy crude. These data contradict the DEIR's conclusion that the project is more likely to deliver light crude than heavy crude. (See apps. C.1, C.2.) However, the DEIR fails to include and evaluate any data on the quality of this dwindling pipeline crude input that the project could enable the refinery to replace.

[19] This API range is 933–951 kg/m^3 as density; 0.933–0.951 specific gravity. See Karras, 2010. Combustion emissions from refining lower quality oil: What is the global warming potential? *Env. Sci. Technol.* 44(24). DOI: 10.1021/es1019965 (esp. SI at S41); Karras, 2011. *Oil Refinery CO_2 Performance Measurement;* Union of Concerned Scientists: Berkeley, CA (App. 2 at 2-53).

22. The DEIR does not evaluate or disclose data on the availability of crude sources with quality similar to that of the refinery's dwindling California crude supplies that the project could replace. As stated, the project is likely to replace California pipeline crude that the DEIR would classify as 'heavy.' (See comment 21.) Data are available on the quality and availability of crude streams that could be delivered by rail to replace this pipeline stream. For example, the largest supply of such 'heavy' crude in North America, and the one that is projected to grow the most, is from the Canadian tar sands,[20] and Canada already accounts for most (55%) of the crude sent into California by rail as of 2013.[21] These data further contradict the DEIR's conclusion that the project is more likely to deliver light crude than heavy crude. (See apps. C.1, C.2.) However, the DEIR fails to include and evaluate data on the quality and availability of San Joaquin Valley 'look-alike' crude streams that the project could enable the refinery to replace.

23. The DEIR does not disclose and evaluate data on the feasibility of replacing dwindling California crude oils from growing domestic sources that could be brought to the Benicia refinery by rail in large amounts. The DEIR asserts that the refinery's configuration limits the crude blends it can process efficiently to blends that are not lighter than 36 ºAPI. (See apps. C.1, C.2.) In other words, if it replaces too much of its heavy crude input with very light crude the refinery cannot run properly. Because the project likely would replace the California pipeline component of the refinery's crude blend, which is much denser than 36 ºAPI (see comments 6–17, 21), this would require a new crude supply that is *not* lighter than 36 ºAPI. However, the vast majority of crude produced and virtually all of the projected crude production growth in the U.S. Northern Great Plains (Bakken) and Gulf Coast (Eagle Ford) is lighter than 40 ºAPI according to the EIA[22]—far *lighter* than this 36 ºAPI cutoff. These data further contradict the DEIR's conclusion that the project is more likely to deliver light crude than heavy crude, but the DEIR fails to include and evaluate them.

24. The DEIR omits available cost data that contradict its underestimate of the role price discounts play in the choice of crude oils that the project could deliver. Although it acknowledges that price is a factor in Valero's choice of crude oils, the DEIR asserts "the cost of crude is but one factor among many" (App. C.1-1) without disclosing, for example, that crude oil can account for up to 90% of refinery operating costs.[23]

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[20] *ST98–2013: Alberta's Energy Reserves 2012 and Supply/Demand Outlook 2013–2022;* Energy Resources Conservation Board: Alberta, Canada. ISSN 1910–4235. (www.ercb.ca).
[21] See: http://energyalmanac.ca.gov/petroleum/statistics/2013_crude_by_rail (dnldd 9/8/14).
[22] See *U.S. Crude Oil Production Forecast—Analysis of Crude Types;* EIA (2014): www.ei.gov.
[23] U.S. Chemical Safety and Hazard Investigation Board, 2013. *Interim Investigation Report, Chevron Richmond Refinery Fire;* see *Operational Changes* at "opportunity crudes" finding.

25. Data showing that the project could result in refining large amounts of 'heavy' Canadian crude are not disclosed by the DEIR. The DEIR asserts that the project could deliver "only so much" heavy Canadian crude because, it asserts, the refinery cannot process crude blends denser than 20 ºAPI or crude blends with more than 1.9% sulfur. (DEIR at C.1-2.) It fails to support this assertion with any oil quality data and omits readily available data that contradict this assertion. For example, it acknowledges the project could deliver 'Husky Synthetic Blend' (HSB) and 'Western Canadian Select' (WCS) from Canada. (DEIR at 3-23, 3-24.) However, the DEIR fails to include available data on the average densities (32.1 and 20.7 ºAPI) and sulfur contents (0.10 and 3.52 wt. %) of the HSB and WCS crude streams, respectively,[24] and omits the fact that a 1-to-1 volume blend of these oils would be 26 ºAPI and 1.87% wt. sulfur. See Table 2. The DEIR would classify this 26 ºAPI 1.87% sulfur blend as 'heavy sour' (see DEIR Figure 3-4), but it is not denser than 20 ºAPI and does not have more than 1.9% sulfur. Based on the crude blends the DEIR states that the refinery could process, this 'heavy' Canadian crude blend could be delivered and processed as 100% of refinery input. Thus, the DEIR omits facts showing its assertion that project deliveries of Canadian "crudes would have to be offset by purchases of light sweet crudes" (DEIR at C.1-2) is incorrect.

Table 2. Example calculation for the density and sulfur content of a crude blend: 50% Western Canadian Select and 50% Husky Synthetic Blend (50/50 WCS/HSB blend).

Density	Crude volume	Crude mass	Crude density	API gravity
HSB crude	1 m^3	864 kg [(a)]	864.0 kg/m^3 [(a)]	32 ºAPI [(a)]
WCS crude	1 m^3	929 kg [(a)]	928.9 kg/m^3 [(a)]	21 ºAPI [(a)]
50/50 blend	2 m^3	1,793 kg [(b)]	896.5 kg/m^3 [(c)]	26 ºAPI [(d)]
Sulfur	Crude volume	Crude mass	Sulfur mass	Sulfur wt. %
HSB crude	1 m^3	864 kg [(a)]	0.86 kg [(a)]	0.10 [(a)]
WCS crude	1 m^3	929 kg [(a)]	32.70 kg [(a)]	3.52 [(a)]
50/50 blend	2 m^3	1,793 kg [(b)]	33.56 kg [(b)]	1.87 [(e)]

(a) Data reported.[24] (b) Sum of the mass contributed by each crude in the blend. (c) Calculated as the mass of crude in the blend divided by the crude blend volume. (d) Calculated from the standard conversion ºAPI = (141.5/specific gravity) – 131.5 (the specific gravity of crude is its density divided by the density of water, 1,000 kg/m^3). (e) Sulfur wt. % = the mass of sulfur in the blend/the mass of the blend x 100.

26. The DEIR fails to identify 'tar sands' crude oil streams that the project could deliver to the refinery. For example, readily available data (www.crudemonitor.ca) identify at least fourteen Canadian crude streams that the DEIR states the project could deliver (DEIR at 3-23, 3-24), including WCS and HSB, as containing bitumen-derived

[24] Data are five-year averages from www.crudemonitor.ca; accessed 9/13/14.

oils, but the DEIR does not identify any of these crude streams as bitumen-derived or 'tar sands' oils. Several additional 'tar sands' crude streams are available from the same region of Canada. (Id.) The DEIR does not identify those additional crude streams as containing bitumen-derived oils, or even identify them as oils the project could deliver.

27. The DEIR's conclusion that the project *could not* lead to processing large amounts of Canadian 'tar sands' oil at this refinery is unsupported and incorrect. The City could have considered the data and information identified in comments 21–26. Had it done so, the City could have concluded that the project, over its operating life, is very likely to deliver a large volume of 'heavy' crude, and is likely to enable the processing of crude oils derived from Canadian-produced bitumen at the Benicia refinery in large amounts. The DEIR, however, fails to disclose or evaluate data and information showing that its conclusion, that "[t]here is no reason to believe … Valero would be more likely to purchase heavy Canadian crudes than … crudes that are lighter and sweeter" (App. C.1-1), is unsupported and incorrect.

28. Data showing that the project could introduce more contaminated feedstock into existing refinery processes and equipment are not disclosed by the DEIR. As stated, the project is likely to deliver, and enable the refinery to process, bitumen-derived 'tar sands' oils in large amounts. (See comments 21–27.) The DEIR, however, does not include any data to describe the quality of this fundamentally different basic feedstock. Such data are available. For example, the USGS has reported elevated nitrogen, sulfur, organic acid (TAN), nickel, lead, and vanadium concentrations in natural bitumen,[25] and comparisons with other data suggest elevated BTEX (benzene, ethyl benzene, toluene, and xylenes) concentrations in bitumen-derived crude blends.[26] The DEIR thus does not disclose available data indicating that the project could increase the concentrations of toxic elements and toxic gases in crude blends stored and processed in the refinery.

29. The DEIR fails to consider the potential that bringing larger amounts of contaminants into the refinery will result in releasing larger amounts of contaminants from the refinery. For example, research has linked increased partial pressures of toxic gases in refinery equipment[27] and increased refinery emissions into air[28] and water[29] to elevated concentrations of the contaminants causing those effects in

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[25] Meyer et al., 2007. *Heavy oil and natural bitumen resources in geological basins of the world;* U.S. Geological Survey (http://pubs.usgs.gov/of/2007/1084); compare with 'medium oils' avg.
[26] Compare data from www.crudemonitor.ca with the average for 'medium oils' (avg. 22.4 ºAPI; in the range processed at Benicia) in Meyer et al. (2007) cited above.
[27] See EIR SCH# 2011062042 at Appendix A4.13-REL.
[28] See Wilhelm et al., 2007. *Env. Sci. Technol.* 41(13). DOI: 10.1021/es062742j.
[29] *Dirty Crude;* CBE Report 94-1. Communities for a Better Environment: Oakland, CA (1994).

refinery crude feeds. Such findings are further strongly supported by fundamental physical laws—persistent toxic elements are not destroyed by refining processes and do not simply 'disappear' after entering refineries, and toxic gases that are present in refinery equipment in greater amounts tend to leak out at greater rates. The DEIR, however, fails to disclose or consider evidence indicating the potential for increasing 'pass-through' of contaminants from project crude supplies fed to existing refinery equipment into the atmosphere and aquatic environment in a around the refinery.

30. Data showing that the project could introduce denser, higher sulfur crude oils than current blends processed by the refinery are not disclosed by the DEIR. The DEIR acknowledges that denser, higher sulfur crude oils generally require additional processing (DEIR at 3-8), however, it does not disclose the density or sulfur content of crude oils that the project could deliver for processing in larger amounts. Such data are available. For example, data summarized in Table 3 show that a diluted bitumen 'dilbit' crude streams the project could deliver to the refinery are substantially denser and higher in sulfur than the average imported crude stream refined at Benicia from 2010–2012. The DEIR, however, fails to include available data describing the extent to which the project could enable the delivery and processing of denser, higher sulfur crude at Benicia.

Table 3. Density and sulfur content of selected bitumen-containing crude streams that the project could deliver *versus* total current Benicia refinery foreign crude imports.

Crude Blend	Density of Crude Blend (kg/m^3)	(°API)	Crude Sulfur Content (wt. %)
Benicia 2010–2012 imports[a]	894	27	1.28
Access Western Blend[b]	924	22	3.95
Borealis Heavy Blend[b]	925	21	3.75
Christina Dilbit Blend[b]	924	21	3.85
Cold Lake[b]	928	21	3.79
Kearl Lake[b]	926	21	3.86
Peace River Heavy[b]	928	21	5.08
Western Canadian Select[b]	929	21	3.52

(a) Weighted average of all foreign crude processed (www.eia.gov/petroleum/imports/companylevel).
(b) Most recent 5-year average (www.crudemonitor.ca).

31. The DEIR does not consider the potential for increasing process intensity needed for denser, higher sulfur crude oils delivered by the project to increase refinery combustion emissions. The project is likely to result in processing denser, higher sulfur bitumen-derived oil at the Benicia refinery in larger amounts. (See comments 21–30.) Although it admits denser, higher sulfur feedstock generally requires more processing (DEIR at 3-8), the DEIR fails to consider the increased fuel combustion—and thus

combustion emissions—that could result from the increased energy requirements for this more intensive processing. For example, peer reviewed work demonstrates that processing bitumen-derived crude can increase refinery energy intensity, thereby increasing refinery emissions combustion products such as carbon dioxide (CO_2), the major greenhouse gas emitted by refineries.[30] The DEIR, however, does not disclose and compare available estimates of current refinery combustion emissions and potential refinery combustion emissions from the project's crude switch.

32. The DEIR does not disclose or evaluate potential project emissions from feedstock quality-related equipment failures and process upsets. As stated, the project is likely to result in more intensive processing of denser, higher sulfur, more contaminated and more acidic oil feedstock. (See comments 21–31.) The resultant combination of greater process temperatures, pressures, and volumes of hazardous or corrosive compounds in some process units could increase the frequency and magnitude of refinery equipment failures and process upsets. Such incidents typically emit substantial amounts of air pollutants over short periods from flares, pressure relief devices, vessel ruptures, fires, or combinations of those emission pathways. Data and analysis regarding such crude quality-related incidents at Bay Area refineries. For example, the U.S. Chemical Safety Board has documented causal factors related to crude density and sulfur content in the fatal fire at Avon in 1999 and the disastrous fire and air release at Richmond in 2012.[31] The DEIR, however, does not disclose or evaluate potential incident emissions that could result from the project's crude switch.

33. The DEIR does not disclose or evaluate data indicating that the project could result in an increase in GHG-intensive refinery hydrogen plant production. The DEIR states that the current refinery hydrogen supply is sufficient, and that Valero will decide in the future whether to build and commission a new hydrogen production plant that would increase the refinery hydrogen supply. (DEIR at 3-12.) However, the project is likely to result in processing denser, higher sulfur crude oils such as bitumen-derived oils in greater amounts. (See comments 21–31.) Processing crude that is denser, higher in sulfur, or both—and especially processing crude derived from tar sands—can increase refinery hydrogen demand substantially, and hydrogen production to meet this demand can increase refinery GHG emissions substantially.[32] The DEIR, however, does not

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[30] See Abella and Bergerson, 2012. *Env. Sci. Technol.* DOI: 10.1021/es3018682; Karras, 2010. *Env. Sci. Technol.* DOI: 10.1021/es1019965; and Bredeson et al., 2010. *Int. J. Life Cycle Assess.* DOI: 10.1007/s11367-010-0204-3.

[31] See U.S. Chemical Safety and Hazard Investigation Board (CSB), 2013. *Interim Investigation Report, Chevron Richmond Refinery Fire;* and CSB, 2001. *Investigation Report, Refinery Fire Incident, Tosco Avon Refinery, Report No. 99-014-I-CA.* (www.csb.gov).

[32] Abella and Bergerson, 2012; Karras, 2010; and Bredeson et al., 2010 as cited above.

disclose or evaluate the quality of crude deliveries the project could enable the effects of processing that crude on refinery hydrogen demand, hydrogen production to meet that demand, and resultant project-related emissions.

34. The project crude switch could increase refinery hydrogen demand and production by changing production in existing refinery equipment, but this is not disclosed or evaluated in the DEIR. As stated, the switch to denser, higher sulfur crude enabled by the project could increase refinery emissions by increasing refinery hydrogen demand. (See comments 21–31, 33.) Moreover, the project's crude switch requires more hydrogen *because* the processing of denser, higher sulfur oils requires hydroprocessing units to increase rate, hydrogen partial pressure, or both.[33] These hydroprocessing units that are inextricably interrelated with oil feed quality and the not-yet-commissioned expansion of hydrogen production—the refinery's hydrocracker and its hydrotreating units (Valero calls them 'hydrofining' units—are existing equipment, as the DEIR acknowledges. (DEIR at 3-12.) Thus, the project could change the existing refinery's processing in ways that increase refinery emissions from existing *and* permitted equipment. Therefore, data and information that the DEIR fails to disclose or evaluate contradicts its assertion (DEIR at 4.1-11) that the project "would not result in any emissions increases from existing, permitted Refinery equipment."

35. The DEIR's conclusion that the project's crude switch *would not* increase emissions from existing and permitted refinery equipment is unsupported and incorrect. The City could have considered the data and information identified in comments 28–34 in its evaluation of the proposed project. Had it done so, the City could have concluded that the project, by enabling the refining of denser, more contaminated, and/or more corrosive crude feedstock, has the reasonable potential to increase emissions from existing and permitted refinery equipment. Moreover, because the DEIR does not disclose or evaluate the data and information that is available to document these potential impacts, and does not evaluate them, its conclusion that the project would not increase emissions from existing and permitted refinery equipment is unsupported and incorrect.

36. Current (baseline) data on the density and sulfur content of crude blends processed by the refinery are inappropriately omitted from the DEIR. As stated (see comments 21–35), the project could cause environmental impacts by changing the refinery's oil feedstock quality. Accurate, adequately supported evaluation of these potential impacts thus requires describing the change in oil feed quality by, among other things, disclosing the density and sulfur content of crude blends currently processed. The DEIR, however, claims that these data are trade secret. (DEIR at D-1.) This is clearly

[33] See Abella and Bergerson, 2012; Karras, 2010; and Bredeson et al., 2010 as cited above.

inaccurate because these data are not secret. For example, the average 'baseline' density and sulfur content of crude blends processed by Chevron at Richmond,[34] Phillips 66 at Santa Maria,[35] and indeed, each Bay Area refinery,[36] are reported publicly—and the density and sulfur content of each foreign crude shipment processed by each U.S. refinery is disclosed publicly along with its quantity every month (see Table 4). Therefore, the DEIR's secrecy claim is incorrect and its failure to disclose these data inappropriately truncates the DEIR's environmental analysis.

37. Data identifying the domestic crude oils currently processed by the refinery are inappropriately omitted from the DEIR. As stated, accurate, adequately supported evaluation of project impacts requires disclosing project changes in oil feed quality. (See comments 21–36.) Since many of those data are crude stream-specific, this disclosure must include, among other things, identifying the specific domestic crude streams processed by the refinery in the project baseline. The DEIR does not disclose that information, and in this case, its 'trade secrets' claim (DEIR at D-1) is inaccurate to the point of absurdity. The fact that Bay Area refineries including Valero in Benicia process two domestic crude streams—San Joaquin Valley Pipeline (SJV) and Alaskan North Slope (ANS) crude streams—is well known and widely reported.[36] Thus, these data are not secret. The DEIR's secrecy claim is incorrect and its failure to disclose these data inappropriately truncates its analysis.

38. Data on other properties (other than density and sulfur content) of oil feedstocks currently processed by the refinery are inappropriately omitted from the DEIR. Accurate, adequately supported evaluation of potential project impacts must describe changes in the quality of oil feedstocks by, among other things, disclosing other properties and contaminants of the oil processed (besides density and sulfur content). The DEIR does not disclose any of these data, claiming that all of the properties of crude oil and blends processed in the project baseline are trades secrets. (DEIR at D-1.) However, the relevant and needed data are not secret. In one example, Chevron reports cadmium, nickel, selenium, vanadium, and mercury as well as sulfur concentrations for of its current crude slate and for the separately purchased gas oil feedstocks processed in its Richmond hydroprocessing units.[37] Another example: dozens of properties of publicly traded crude streams are reported publicly by oil traders on others on the worldwide web—and these publicly available data include assays for the Alaskan North Slope (ANS) stream processed at Benicia among many others. The excerpt in Table 5 is an

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[34] EIR SCH# 2011062042 at App. A4.3-URM.
[35] EIR SCH# 2013071028 at 2-27.
[36] See Karras, 2012; and Karras, 2011 as cited above.
[37] EIR SCH# 2011062042 at Chevron Transmittals 24, 44 (www.Chevronmodernization.com).

Table 4. (page 1 of 3) **EIA 'Company Level Imports' excerpt—Data on all crude shipments processed at the Valero Benicia refinery in 2010. Shown: month, country of origin, quantity (in 1,000 barrels), sulfur content (wt. %) and density (°API) of crude shipment. Data source: www.eia.gov/petroleum/imports/companylevel/archive; downloaded 9/7/2014.**

RPT_PERIOD	PROD_NA	CNTRY_NAME	QUANTITY	SULFUR	APIGR	PCOMP_RNAM	PCOMP_SNAM
Jan-10	Crude Oi	COLOMBIA	366	0.61	29.7	VALERO REFINING CO	BENICIA
Feb-10	Crude Oi	COLOMBIA	214	0.72	26.3	VALERO REFINING CO	BENICIA
Feb-10	Crude Oi	COLOMBIA	331	1.72	20.8	VALERO REFINING CO	BENICIA
Feb-10	Crude Oi	COLOMBIA	331	1.72	20.8	VALERO REFINING CO	BENICIA
Feb-10	Crude Oi	COLOMBIA	331	1.72	20.8	VALERO REFINING CO	BENICIA
Feb-10	Crude Oi	COLOMBIA	343	0.72	26.3	VALERO REFINING CO	BENICIA
Feb-10	Crude Oi	COLOMBIA	351	0.72	26.3	VALERO REFINING CO	BENICIA
Feb-10	Crude Oi	COLOMBIA	368	0.61	29.6	VALERO REFINING CO	BENICIA
Feb-10	Crude Oi	PERU	334	1.28	19.3	VALERO REFINING CO	BENICIA
Mar-10	Crude Oi	ANGOLA	544	1.3	23.17	VALERO REFINING CO	BENICIA
Mar-10	Crude Oi	COLOMBIA	332	1.72	18.6	VALERO REFINING CO	BENICIA
Mar-10	Crude Oi	ECUADOR	342	2.07	20.5	VALERO REFINING CO	BENICIA
Apr-10	Crude Oi	ANGOLA	535	1.3	23	VALERO REFINING CO	BENICIA
Apr-10	Crude Oi	ANGOLA	530	1.3	23.1	VALERO REFINING CO	BENICIA
Apr-10	Crude Oi	BRAZIL	400	0.77	20	VALERO REFINING CO	BENICIA
Apr-10	Crude Oi	RUSSIA	492	0.54	35.2	VALERO REFINING CO	BENICIA
May-10	Crude Oi	CANADA	337	3.54	22.1	VALERO REFINING CO	BENICIA
May-10	Crude Oi	RUSSIA	211	0.54	35	VALERO REFINING CO	BENICIA
May-10	Crude Oi	RUSSIA	298	0.54	35	VALERO REFINING CO	BENICIA
May-10	Crude Oi	RUSSIA	467	0.54	34.8	VALERO REFINING CO	BENICIA
Jun-10	Crude Oi	ANGOLA	533	1.3	23.3	VALERO REFINING CO	BENICIA
Jun-10	Crude Oi	CANADA	337	3.54	22	VALERO REFINING CO	BENICIA
Jun-10	Crude Oi	COLOMBIA	297	0.61	30.1	VALERO REFINING CO	BENICIA
Jun-10	Crude Oi	RUSSIA	491	0.54	35.8	VALERO REFINING CO	BENICIA
Jun-10	Crude Oi	RUSSIA	341	0.54	35	VALERO REFINING CO	BENICIA
Jun-10	Crude Oi	RUSSIA	323	0.54	35.4	VALERO REFINING CO	BENICIA
Jul-10	Crude Oi	AUSTRALIA	429	0.21	18.8	VALERO REFINING CO	BENICIA
Jul-10	Crude Oi	ECUADOR	323	2.07	18.4	VALERO REFINING CO	BENICIA
Jul-10	Crude Oi	RUSSIA	347	0.54	34.8	VALERO REFINING CO	BENICIA
Jul-10	Crude Oi	RUSSIA	327	0.54	34.7	VALERO REFINING CO	BENICIA
Jul-10	Crude Oi	RUSSIA	342	0.54	34.7	VALERO REFINING CO	BENICIA
Aug-10	Crude Oi	RUSSIA	479	0.54	35.4	VALERO REFINING CO	BENICIA
Aug-10	Crude Oi	RUSSIA	276	0.54	36	VALERO REFINING CO	BENICIA
Aug-10	Crude Oi	RUSSIA	468	0.54	36	VALERO REFINING CO	BENICIA
Aug-10	Crude Oi	RUSSIA	442	0.54	36.1	VALERO REFINING CO	BENICIA
Aug-10	Crude Oi	RUSSIA	267	0.54	34.3	VALERO REFINING CO	BENICIA
Sep-10	Crude Oi	ECUADOR	330	2.07	18.2	VALERO REFINING CO	BENICIA
Sep-10	Crude Oi	RUSSIA	300	0.54	35.2	VALERO REFINING CO	BENICIA
Sep-10	Crude Oi	RUSSIA	228	0.54	35.3	VALERO REFINING CO	BENICIA
Sep-10	Crude Oi	RUSSIA	448	0.54	35.4	VALERO REFINING CO	BENICIA
Sep-10	Crude Oi	RUSSIA	228	0.54	35.5	VALERO REFINING CO	BENICIA
Oct-10	Crude Oi	CANADA	342	3.54	21.2	VALERO REFINING CO	BENICIA
Oct-10	Crude Oi	ECUADOR	365	2.07	18.3	VALERO REFINING CO	BENICIA
Oct-10	Crude Oi	OMAN	361	1.04	32.1	VALERO REFINING CO	BENICIA
Oct-10	Crude Oi	OMAN	360	1.04	31.9	VALERO REFINING CO	BENICIA
Oct-10	Crude Oi	OMAN	411	1.04	31.8	VALERO REFINING CO	BENICIA
Oct-10	Crude Oi	OMAN	219	1.04	31.8	VALERO REFINING CO	BENICIA
Oct-10	Crude Oi	OMAN	196	1.04	32	VALERO REFINING CO	BENICIA
Oct-10	Crude Oi	RUSSIA	299	0.29	35.6	VALERO REFINING CO	BENICIA
Oct-10	Crude Oi	RUSSIA	432	0.29	35.5	VALERO REFINING CO	BENICIA
Nov-10	Crude Oi	OMAN	344	1.04	31.2	VALERO REFINING CO	BENICIA
Nov-10	Crude Oi	OMAN	584	1.04	31.9	VALERO REFINING CO	BENICIA
Nov-10	Crude Oi	RUSSIA	343	0.54	34.8	VALERO REFINING CO	BENICIA
Dec-10	Crude Oi	RUSSIA	436	0.54	35.3	VALERO REFINING CO	BENICIA
Dec-10	Crude Oi	RUSSIA	309	0.54	34.8	VALERO REFINING CO	BENICIA
Dec-10	Crude Oi	RUSSIA	94	0.54	32.1	VALERO REFINING CO	BENICIA

Table 4. (page 2 of 3) **EIA 'Company Level Imports' excerpt—Data on all crude shipments processed at the Valero Benicia refinery in 2011. Shown: month, country of origin, quantity (in 1,000 barrels), sulfur content (wt. %) and density (°API) of crude shipment. Data source: www.eia.gov/petroleum/imports/companylevel/archive; downloaded 9/7/2014.**

RPT_PERIOD	PROD_NA	CNTRY_NAME	QUANTITY	SULFUR	APIGR	PCOMP_RNAM	PCOMP_SNAM
Feb-11	Crude Oil	BRAZIL	320	0.77	20.2	VALERO REFINING CO	BENICIA
Mar-11	Crude Oil	BRAZIL	332	0.77	20.2	VALERO REFINING CO	BENICIA
Mar-11	Crude Oil	BRAZIL	484	0.72	20.5	VALERO REFINING CO	BENICIA
Mar-11	Crude Oil	BRAZIL	337	0.72	20.5	VALERO REFINING CO	BENICIA
Mar-11	Crude Oil	COLOMBIA	345	0.61	29.2	VALERO REFINING CO	BENICIA
Mar-11	Crude Oil	ECUADOR	355	2.07	19.1	VALERO REFINING CO	BENICIA
Apr-11	Crude Oil	ANGOLA	604	1.3	23.1	VALERO REFINING CO	BENICIA
Apr-11	Crude Oil	ANGOLA	345	1.3	22.7	VALERO REFINING CO	BENICIA
Apr-11	Crude Oil	BRAZIL	336	0.77	20.6	VALERO REFINING CO	BENICIA
Apr-11	Crude Oil	COLOMBIA	332	0.61	28.9	VALERO REFINING CO	BENICIA
May-11	Crude Oil	BRAZIL	520	0.77	20.1	VALERO REFINING CO	BENICIA
May-11	Crude Oil	BRAZIL	330	0.77	20.1	VALERO REFINING CO	BENICIA
May-11	Crude Oil	BRAZIL	520	0.77	20.1	VALERO REFINING CO	BENICIA
May-11	Crude Oil	COLOMBIA	332	0.61	28.9	VALERO REFINING CO	BENICIA
May-11	Crude Oil	ECUADOR	351	2.07	19	VALERO REFINING CO	BENICIA
May-11	Crude Oil	IRAQ	349	2.18	29.5	VALERO REFINING CO	BENICIA
May-11	Crude Oil	IRAQ	350	2.18	29.5	VALERO REFINING CO	BENICIA
Jun-11	Crude Oil	ANGOLA	328	1.3	23	VALERO REFINING CO	BENICIA
Jun-11	Crude Oil	BRAZIL	539	0.58	28.8	VALERO REFINING CO	BENICIA
Jun-11	Crude Oil	BRAZIL	324	0.58	28.8	VALERO REFINING CO	BENICIA
Jun-11	Crude Oil	IRAQ	349	2.18	30.9	VALERO REFINING CO	BENICIA
Jun-11	Crude Oil	IRAQ	355	2.18	31	VALERO REFINING CO	BENICIA
Jul-11	Crude Oil	ANGOLA	328	1.3	23	VALERO REFINING CO	BENICIA
Jul-11	Crude Oil	ANGOLA	328	1.3	23	VALERO REFINING CO	BENICIA
Jul-11	Crude Oil	ANGOLA	421	1.3	23	VALERO REFINING CO	BENICIA
Jul-11	Crude Oil	ANGOLA	564	1.3	23.2	VALERO REFINING CO	BENICIA
Jul-11	Crude Oil	ANGOLA	336	1.3	23.2	VALERO REFINING CO	BENICIA
Jul-11	Crude Oil	COLOMBIA	359	0.61	28.6	VALERO REFINING CO	BENICIA
Jul-11	Crude Oil	COLOMBIA	350	0.55	30.4	VALERO REFINING CO	BENICIA
Jul-11	Crude Oil	ECUADOR	360	2.07	18.9	VALERO REFINING CO	BENICIA
Jul-11	Crude Oil	ECUADOR	324	2.07	19.2	VALERO REFINING CO	BENICIA
Jul-11	Crude Oil	IRAQ	362	2.18	30	VALERO REFINING CO	BENICIA
Jul-11	Crude Oil	IRAQ	350	2.18	29.9	VALERO REFINING CO	BENICIA
Jul-11	Crude Oil	IRAQ	344	2.18	29.9	VALERO REFINING CO	BENICIA
Jul-11	Crude Oil	IRAQ	296	2.18	29.9	VALERO REFINING CO	BENICIA
Aug-11	Crude Oil	ANGOLA	587	1.3	23.5	VALERO REFINING CO	BENICIA
Aug-11	Crude Oil	ANGOLA	339	1.3	23.3	VALERO REFINING CO	BENICIA
Aug-11	Crude Oil	ANGOLA	396	1.3	23.4	VALERO REFINING CO	BENICIA
Aug-11	Crude Oil	AUSTRALIA	439	0.21	19.8	VALERO REFINING CO	BENICIA
Aug-11	Crude Oil	COLOMBIA	349	0.61	28.3	VALERO REFINING CO	BENICIA
Aug-11	Crude Oil	ECUADOR	324	2.07	19.2	VALERO REFINING CO	BENICIA
Aug-11	Crude Oil	IRAQ	296	2.18	29.5	VALERO REFINING CO	BENICIA
Aug-11	Crude Oil	IRAQ	599	2.18	29.7	VALERO REFINING CO	BENICIA
Aug-11	Crude Oil	IRAQ	397	2.18	29.7	VALERO REFINING CO	BENICIA
Aug-11	Crude Oil	IRAQ	354	2.18	30.1	VALERO REFINING CO	BENICIA
Sep-11	Crude Oil	ANGOLA	540	1.3	23.1	VALERO REFINING CO	BENICIA
Sep-11	Crude Oil	ANGOLA	501	1.3	23.1	VALERO REFINING CO	BENICIA
Sep-11	Crude Oil	ANGOLA	401	1.3	23.3	VALERO REFINING CO	BENICIA
Sep-11	Crude Oil	ECUADOR	349	2.07	19.7	VALERO REFINING CO	BENICIA
Sep-11	Crude Oil	IRAQ	341	2.18	29.5	VALERO REFINING CO	BENICIA
Oct-11	Crude Oil	ANGOLA	460	1.3	23.1	VALERO REFINING CO	BENICIA
Oct-11	Crude Oil	ANGOLA	205	1.3	23.6	VALERO REFINING CO	BENICIA
Oct-11	Crude Oil	ANGOLA	359	1.3	23.1	VALERO REFINING CO	BENICIA
Oct-11	Crude Oil	ECUADOR	348	2.07	19.1	VALERO REFINING CO	BENICIA
Oct-11	Crude Oil	IRAQ	334	2.18	29	VALERO REFINING CO	BENICIA
Oct-11	Crude Oil	IRAQ	290	2.18	29.8	VALERO REFINING CO	BENICIA
Oct-11	Crude Oil	IRAQ	350	2.18	29	VALERO REFINING CO	BENICIA
Oct-11	Crude Oil	IRAQ	351	2.18	28.6	VALERO REFINING CO	BENICIA
Oct-11	Crude Oil	IRAQ	345	2.18	29.1	VALERO REFINING CO	BENICIA
Oct-11	Crude Oil	IRAQ	318	2.18	29	VALERO REFINING CO	BENICIA
Nov-11	Crude Oil	ANGOLA	337	1.3	23.2	VALERO REFINING CO	BENICIA
Nov-11	Crude Oil	BRAZIL	490	0.3	22.7	VALERO REFINING CO	BENICIA
Nov-11	Crude Oil	BRAZIL	331	0.3	22.4	VALERO REFINING CO	BENICIA
Nov-11	Crude Oil	CANADA	276	3.75	21.5	VALERO REFINING CO	BENICIA
Nov-11	Crude Oil	COLOMBIA	359	0.61	28.4	VALERO REFINING CO	BENICIA
Nov-11	Crude Oil	IRAQ	345	2.18	29.1	VALERO REFINING CO	BENICIA
Nov-11	Crude Oil	IRAQ	507	2.18	29.2	VALERO REFINING CO	BENICIA
Nov-11	Crude Oil	IRAQ	421	2.18	29.2	VALERO REFINING CO	BENICIA
Dec-11	Crude Oil	AUSTRALIA	353	0.39	17.5	VALERO REFINING CO	BENICIA
Dec-11	Crude Oil	BRAZIL	551	0.3	22.5	VALERO REFINING CO	BENICIA
Dec-11	Crude Oil	BRAZIL	402	0.3	22.3	VALERO REFINING CO	BENICIA
Dec-11	Crude Oil	COLOMBIA	359	0.61	28.4	VALERO REFINING CO	BENICIA
Dec-11	Crude Oil	IRAQ	356	2.18	30.1	VALERO REFINING CO	BENICIA

Table 4. (page 3 of 3) **EIA 'Company Level Imports' excerpt—Data on all crude shipments processed at the Valero Benicia refinery in 2012. Shown: month, country of origin, quantity (in 1,000 barrels), sulfur content (wt. %) and density (°API) of crude shipment. Data source: www.eia.gov/petroleum/imports/companylevel/archive; downloaded 9/7/2014.**

RPT_PERIOD	PROD_NA	CNTRY_NAME	QUANTITY	SULFUR	APIGR	PCOMP_RNAM	PCOMP_SNAM
Jan-12	Crude Oil	ANGOLA	604	0.14	25.8	VALERO REFINING CO (	BENICIA
Jan-12	Crude Oil	ANGOLA	335	0.14	25.8	VALERO REFINING CO (	BENICIA
Jan-12	Crude Oil	COLOMBIA	358	0.61	29.1	VALERO REFINING CO (	BENICIA
Jan-12	Crude Oil	IRAQ	345	2.18	30.8	VALERO REFINING CO (	BENICIA
Jan-12	Crude Oil	IRAQ	285	2.18	30.8	VALERO REFINING CO (	BENICIA
Jan-12	Crude Oil	IRAQ	125	2.18	30.8	VALERO REFINING CO (	BENICIA
Jan-12	Crude Oil	IRAQ	348	2.18	30.8	VALERO REFINING CO (	BENICIA
Jan-12	Crude Oil	IRAQ	227	2.18	30.8	VALERO REFINING CO (	BENICIA
Feb-12	Crude Oil	COLOMBIA	365	0.72	25.4	VALERO REFINING CO (	BENICIA
Feb-12	Crude Oil	COLOMBIA	346	0.72	26.2	VALERO REFINING CO (	BENICIA
Feb-12	Crude Oil	COLOMBIA	284	1.63	19.5	VALERO REFINING CO (	BENICIA
Feb-12	Crude Oil	IRAQ	393	2.18	29.8	VALERO REFINING CO (	BENICIA
Mar-12	Crude Oil	BRAZIL	521	0.77	20.8	VALERO REFINING CO (	BENICIA
Mar-12	Crude Oil	BRAZIL	433	0.77	20.9	VALERO REFINING CO (	BENICIA
Mar-12	Crude Oil	COLOMBIA	349	0.72	25.5	VALERO REFINING CO (	BENICIA
Mar-12	Crude Oil	COLOMBIA	149	0.72	25.9	VALERO REFINING CO (	BENICIA
Mar-12	Crude Oil	IRAQ	301	2.18	30.1	VALERO REFINING CO (	BENICIA
Mar-12	Crude Oil	IRAQ	401	2.18	31.2	VALERO REFINING CO (	BENICIA
Mar-12	Crude Oil	OMAN	183	1.04	30.8	VALERO REFINING CO (	BENICIA
Apr-12	Crude Oil	ANGOLA	606	1.3	23.2	VALERO REFINING CO (	BENICIA
Apr-12	Crude Oil	ANGOLA	339	1.3	22.9	VALERO REFINING CO (	BENICIA
Apr-12	Crude Oil	ANGOLA	206	0.46	25.8	VALERO REFINING CO (	BENICIA
Apr-12	Crude Oil	ANGOLA	371	0.43	26	VALERO REFINING CO (	BENICIA
Apr-12	Crude Oil	BRAZIL	545	0.3	22.9	VALERO REFINING CO (	BENICIA
Apr-12	Crude Oil	CANADA	180	3.54	22.6	VALERO REFINING CO (	BENICIA
Apr-12	Crude Oil	IRAQ	327	2.18	31	VALERO REFINING CO (	BENICIA
May-12	Crude Oil	ANGOLA	328	0.47	26	VALERO REFINING CO (	BENICIA
May-12	Crude Oil	BRAZIL	331	0.3	22.7	VALERO REFINING CO (	BENICIA
May-12	Crude Oil	IRAQ	337	2.18	30	VALERO REFINING CO (	BENICIA
May-12	Crude Oil	IRAQ	329	2.18	30.1	VALERO REFINING CO (	BENICIA
May-12	Crude Oil	IRAQ	344	2.18	30.1	VALERO REFINING CO (	BENICIA
May-12	Crude Oil	RUSSIA	395	0.54	35.4	VALERO REFINING CO (	BENICIA
May-12	Crude Oil	RUSSIA	348	0.54	35.3	VALERO REFINING CO (	BENICIA
Jun-12	Crude Oil	ANGOLA	577	0.47	25.2	VALERO REFINING CO (	BENICIA
Jun-12	Crude Oil	ANGOLA	137	0.47	25	VALERO REFINING CO (	BENICIA
Jun-12	Crude Oil	CANADA	332	3.75	22.3	VALERO REFINING CO (	BENICIA
Jun-12	Crude Oil	COLOMBIA	201	0.72	25.8	VALERO REFINING CO (	BENICIA
Jun-12	Crude Oil	IRAQ	321	2.18	29.5	VALERO REFINING CO (	BENICIA
Jun-12	Crude Oil	IRAQ	275	2.18	29.6	VALERO REFINING CO (	BENICIA
Jun-12	Crude Oil	IRAQ	432	2.18	28.5	VALERO REFINING CO (	BENICIA
Jun-12	Crude Oil	RUSSIA	399	0.54	35.5	VALERO REFINING CO (	BENICIA
Jun-12	Crude Oil	RUSSIA	344	0.54	35.2	VALERO REFINING CO (	BENICIA
Jul-12	Crude Oil	ANGOLA	605	0.43	25.3	VALERO REFINING CO (	BENICIA
Jul-12	Crude Oil	ANGOLA	335	0.43	25.1	VALERO REFINING CO (	BENICIA
Jul-12	Crude Oil	COLOMBIA	360	0.55	30.3	VALERO REFINING CO (	BENICIA
Jul-12	Crude Oil	COLOMBIA	356	0.55	30.7	VALERO REFINING CO (	BENICIA
Jul-12	Crude Oil	COLOMBIA	476	0.72	24.9	VALERO REFINING CO (	BENICIA
Jul-12	Crude Oil	ECUADOR	342	2.07	19.2	VALERO REFINING CO (	BENICIA
Jul-12	Crude Oil	IRAQ	399	2.18	32.3	VALERO REFINING CO (	BENICIA
Jul-12	Crude Oil	IRAQ	348	2.18	32	VALERO REFINING CO (	BENICIA
Aug-12	Crude Oil	CANADA	3	2.8	12.5	VALERO REFINING CO (	BENICIA
Aug-12	Crude Oil	COLOMBIA	341	0.61	28.8	VALERO REFINING CO (	BENICIA
Aug-12	Crude Oil	COLOMBIA	450	0.72	24.9	VALERO REFINING CO (	BENICIA
Aug-12	Crude Oil	COLOMBIA	329	0.72	24.6	VALERO REFINING CO (	BENICIA
Aug-12	Crude Oil	IRAQ	349	2.18	28.9	VALERO REFINING CO (	BENICIA
Aug-12	Crude Oil	OMAN	606	1.04	31.6	VALERO REFINING CO (	BENICIA
Aug-12	Crude Oil	VENEZUELA	358	1.04	30.5	VALERO REFINING CO (	BENICIA
Sep-12	Crude Oil	ANGOLA	584	0.43	25.7	VALERO REFINING CO (	BENICIA
Sep-12	Crude Oil	AUSTRALIA	406	0.39	17.6	VALERO REFINING CO (	BENICIA
Sep-12	Crude Oil	COLOMBIA	329	0.72	24.7	VALERO REFINING CO (	BENICIA
Sep-12	Crude Oil	COLOMBIA	356	0.72	24.9	VALERO REFINING CO (	BENICIA
Sep-12	Crude Oil	ECUADOR	346	2.07	19.1	VALERO REFINING CO (	BENICIA
Sep-12	Crude Oil	IRAQ	178	2.18	28.8	VALERO REFINING CO (	BENICIA
Sep-12	Crude Oil	IRAQ	255	2.18	32	VALERO REFINING CO (	BENICIA
Sep-12	Crude Oil	IRAQ	349	2.18	31.6	VALERO REFINING CO (	BENICIA
Sep-12	Crude Oil	IRAQ	339	2.18	28.5	VALERO REFINING CO (	BENICIA
Sep-12	Crude Oil	OMAN	341	1.04	31.7	VALERO REFINING CO (	BENICIA
Oct-12	Crude Oil	ANGOLA	333	2.07	25.7	VALERO REFINING CO (	BENICIA
Oct-12	Crude Oil	CANADA	299	3.54	20.8	VALERO REFINING CO (	BENICIA
Oct-12	Crude Oil	COLOMBIA	265	0.72	26.9	VALERO REFINING CO (	BENICIA
Oct-12	Crude Oil	IRAQ	339	2.18	28	VALERO REFINING CO (	BENICIA
Oct-12	Crude Oil	IRAQ	328	2.18	28.2	VALERO REFINING CO (	BENICIA
Oct-12	Crude Oil	IRAQ	335	2.18	28	VALERO REFINING CO (	BENICIA
Oct-12	Crude Oil	TRINIDAD & TOBA	359	0.58	32	VALERO REFINING CO (	BENICIA
Nov-12	Crude Oil	ANGOLA	586	0.43	25.3	VALERO REFINING CO (	BENICIA
Nov-12	Crude Oil	ANGOLA	340	0.43	25.3	VALERO REFINING CO (	BENICIA
Nov-12	Crude Oil	IRAQ	351	2.18	28.9	VALERO REFINING CO (	BENICIA
Nov-12	Crude Oil	IRAQ	500	2.18	28.8	VALERO REFINING CO (	BENICIA
Nov-12	Crude Oil	IRAQ	356	2.18	28	VALERO REFINING CO (	BENICIA
Dec-12	Crude Oil	ANGOLA	341	0.43	25.1	VALERO REFINING CO (	BENICIA
Dec-12	Crude Oil	CANADA	315	3.54	21.9	VALERO REFINING CO (	BENICIA
Dec-12	Crude Oil	IRAQ	356	2.18	28.8	VALERO REFINING CO (	BENICIA
Dec-12	Crude Oil	IRAQ	300	2.18	29.2	VALERO REFINING CO (	BENICIA
Dec-12	Crude Oil	IRAQ	310	2.18	29.2	VALERO REFINING CO (	BENICIA

ANS assay (see next page). The DEIR's secrecy claim is incorrect and its failure to disclose the domestic crude streams processed inappropriately truncates its analysis.

39. The DEIR fails to disclose or compare baseline data on the quality of oil feedstock the refinery can process and baseline refinery equipment usage rates. The DEIR's claim that these data are trade secret (DEIR at D-1) is overly broad and incorrect. For example, the density and sulfur content of crude blends that a refinery's unique configuration can process,[38] operable capacities of its key process units,[39] and actual average baseline usage rates,[40] are publicly reported for Bay Area refineries. As stated, the potential change in oil feed quality must be disclosed (see comments 21–38): these data are critical to that disclosure. Indeed, the DEIR's claim that the refinery's configuration cannot refine much heavy Canadian crude (DEIR at B.1-2) is unsupported without disclosing these baseline data regarding the source and quality of crude blends it can process now, is processing now, and could process with the project. Moreover, the contradiction between this claim of limited capacity for denser, higher sulfur crude and the DEIR's admission that refinery hydrogen production—which enables its capacity for denser and higher sulfur crude—could increase concurrently (DEIR at 3-12) further reveals that nondisclosure of these capacity data is a fatal flaw in the DEIR's analysis. The DEIR's claim that all data regarding the current equipment's feedstock quality specifications and usage rates are trade secret is clearly in error, and its failure to describe these data inappropriately truncates its environmental analysis.

40. The DEIR improperly omits disclosing or describing the change in oil feed quality that the project would enable, thereby inappropriately truncating its environmental analysis. The City could have considered the data and information identified in comments 36–39 in its environmental evaluation of the proposed project. Had it done so, the City could have found that publicly available information on current conditions which is needed to evaluate the change in oil feedstock enabled by the project and its resultant impacts is erroneously labeled 'secret' and omitted by the DEIR.

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[38] EIR SCH# 2011062042.

[39] See EIR SCH# 2011062042 at App. 4.3-URM; Worldwide Refining Survey in *Oil & Gas Journal;* Title V air permits for each refinery at the Bay Area Air Quality Management District.

[40] See EIR SCH# 2011062042 at apps. 4.3-URM, 4.3-EI; Bay Area Air Quality Management District Emission Inventory; Regional Water Quality Control Board, San Francisco Bay Region NPDES Permit Fact Sheet for each refinery.

Table 5. Crude Quality Assay—Alaskan North Slope (ANS) Crude (example of public data).

NORTH AMERICA
ALASKA
ALASKAN NORTH SLOPE (ANS)

SOURCE OF SAMPLE	
Reference	A06302
Field	ALASKAN NORTH SLOPE (ANS)
Export Terminal	Valdez Terminal
Source	Valdez incoming pipeline.
Sample Date	3-Jun-02
Date Rec'd	13/06/2002

CRUDE DATA		
Gravity		31.9
Light Hydrocarbon Analysis		
H_2S	ppm wt	< 2
Methane	%wt	-
Ethane	%wt	0.02
Propane	%wt	0.3
Isobutane	%wt	0.51
n-Butane	%wt	1.67
Total C_1 - C_4		2.5
Isopentane	%wt	0.91
n-Pentane	%wt	1.4

ASSAY SUMMARY/TBP DATA	%wt	%vol
Yield on Crude		
Gas to C_4 (corrected)	2.5	3.8
Light Distillate to 149°C (API)	17.55	20.85
Kerosine 149 - 232°C	10.85	11.65
Gas oil 232 - 342°C	18.45	18.4
Residue above 342°C	50.65	45.3
Gas to C_4 (corrected)	2.5	3.8
Total to 95°C (API)	10.35	13.65
149°C	20.05	24.65
175°C	23.55	28.5
232°C	30.9	36.3
342°C	49.35	54.7
369°C	54.25	59.4
509°C	74.85	78.55
550°C	79.6	82.85
585°C	83.45	86.3

Volume expansion of 0.3 per cent vol on crude distributed across whole distillation

TBP cut point °C API		Total Crude	DISTILLATES C_1-95 **	95-175 (C)	C_1-149 (C)	149-232	232-342	342-369	369-509	509-550
Yield on crude	%wt	100.0	7.85	13.2	17.55	10.85	18.45	4.9	20.6	4.75
Yield on crude	%vol	100.0	9.85	14.85	20.85	11.65	18.4	4.7	19.15	4.3
Density at 15°C	kg/litre	0.8655	0.6914	0.7666	0.7276	0.8049	0.8645	0.8968	0.9279	0.9535
Sulphur	%wt	0.93	0.001	0.006	0.002	0.036	0.42	0.99	1.09	1.49
Mercaptan sulphur	%wt	-	0.0014	0.0012	0.0013	0.0008	-	-	-	-
Viscosity at 20°C	cSt	11.04	-	-	-	-	-	-	-	-
30°C		8.28	-	-	-	-	-	-	-	-
40°C		6.42	-	-	-	1.12	-	-	-	-
50°C		-	-	-	-	-	2.98	8.28	-	-
60°C		-	-	-	-	0.88	-	-	26.45	203
100°C		-	-	-	-	-	1.36	2.71	8.27	30.40
Cloud point	°C	-	-	-	-	-	-18	9	-	-
Pour point	°C	-18	-	-	-	-	-18	9	27	-
Wax	%wt	-	-	-	-	-	2.0	11.5	10.0	9.0
Total nitrogen	ppm wt	-	-	-	-	-	47	420	1100	2500
Basic nitrogen	ppm wt	-	-	-	-	-	-	-	375	665
Organic oxygen	%wt	-	-	-	-	-	-	-	0.2	-
Acidity	mgKOH/g	0.10	0.005	-	<0.05	0.01	0.05	0.10	0.10	0.15
Carbon residue	%wt	4.25 (C)	-	-	-	-	-	-	0.1	1.4
Asphaltenes	%wt	1.6 (C)	-	-	-	-	-	-	-	-
Vanadium	ppm wt	25	-	-	-	-	-	-	-	-
Nickel	ppm wt	11	-	-	-	-	-	-	-	-
Iron	ppm wt	1 (C)	-	-	-	-	-	-	-	-
Arsenic	ppb wt	23	-	-	-	-	-	-	-	-
Cadmium	ppb wt	< 6	-	-	-	-	-	-	-	-
Copper	ppb wt	<20	-	-	-	-	-	-	-	-
Lead	ppb wt	< 2	-	-	-	-	-	-	-	-
Mercury	ppb wt	8	-	-	-	-	-	-	-	-
Aromatics	%vol	-	-	-	-	17.5	28.9*	-	-	-
Smoke point	mm	-	-	-	-	23	14	-	-	-
Freezing point	°C	-	-	-	-	-61.5	-14	-	-	-
Cetane Index ASTM D976/IP380		-	-	-	-	36.7/38.9	44.9/47	44.4/ -	-	-
CaUbA	%	-	-	-	-	-	17.1	18.1	17.4	18.9
Refractive index at 70°C		-	-	-	-	-	1.4594	1.4789	1.4946	1.5127
Hydrogen content	%wt	-	-	-	-	13.5	-			
Paraffins	%wt	-	67.7	41.2	52.6	-	-			
Naphthenes	%wt	-	27.5	41.5	36.3	-	-			
Aromatics	%wt	-	4.8	17.3	11.1	-	31.2+			
n-Paraffins	%wt	-	35.9	19.1	26.8	-	-			
Colour stability		-	-	-	-	Stable	Stable			
Naphthalenes	%vol	-	-	-	-	1.11	9.60			
Salt	lb/1000bbl	9	-	-	-	-	-			
Water	%vol	0.10	-	-	-	-	-			
Research Octane Number	(C)	-	69.0	-	-	-	-			

*232 - 342 Aromatics

	%wt /%vol
1 ring	18.3/18.2
2 ring	12.0/10.1
3 ring	0.9/ 0.6

369 - 509 DWO

Density at 15°C	kg/l	0.9317
Viscosity at 40°C	cSt	77.02
60°C	cSt	28.17
100°C	cSt	7.52
Viscosity index		35
Pour point	°C	-21

(C) = Calculated
** = Analysis carried out on 15-95°C fraction

Crude Dry Density at 15°C (kg/l) 0.8655
Crude API (from Dry Density) 31.9

Attachment to Report 51 333 Page 1 of 1

Please see page 1 for a summary of major findings documented by these comments.