ATTACHMENT B

Comments

on

Initial Study/Mitigated Negative Declaration (IS/MND)

for the

Valero Crude by Rail Project

Benicia, California

Use Permit Application 12PLN-00063

July 1, 2013

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I. INTRODUCTION

The Valero Benicia Refinery (Refinery) is proposing to import certain unidentified "North American-sourced crude oils" to the Refinery by railroad (Project). The City of Benicia has issued a draft Initial Study/Mitigated Negative Declaration (IS/MND)[1] for this Project. I was asked to review the IS/MND and prepare comments on the impact of the imported crude on air emissions from the Refinery.

My analyses, presented below, indicate the subject "North American-sourced crudes" that would be imported by rail are likely to include Canadian tar sand crudes blended with diluent or "DilBits". These have the potential to increase emissions compared to the current crude slate, which would result in potentially significant impacts not disclosed in the IS/MND. The "North American-sourced crudes" may also include light sweet shale oil crudes, such as Bakken, which also have the potential to increase emissions, and result in significant environmental impacts, compared to the current crude slate.

The pollutants in the diluent blended with these DilBit crudes and in the light sweet shale crudes include significant amounts of hazardous air pollutants, such as benzene, a potent carcinogen. These would be emitted at many fugitive components in the Refinery, including compressors, pumps, valves, fittings, and tanks, in greater amounts than from other crudes that are currently being refined or have otherwise been proposed.

These increased emissions would result in significant air quality impacts not acknowledged in the IS/MND. These include significant increases in volatile organic compounds (VOCs); hazardous air pollutants, including benzene and lead, which will cause significant health impacts; and highly odiferous sulfur compounds that would individually and cumulatively cause malodors, degrade ambient air quality, increase the incidence of accidental releases, and adversely affect the health of workers and residents around the Refinery. Further, the high acid levels in these crudes would accelerate corrosion of refinery components, contributing to equipment failure and increased accidental releases. Thus, an EIR should be prepared to properly analyze these impacts and identify mitigation measures.

Finally, the Project description is very incomplete and inadequate to sustain the conclusions in the IS/MND. The *sine qua non* of a CEQA analysis is a baseline (physical condition of environment, e.g., emissions, at time of analysis). The baseline is required to evaluate the significance of increases due to the Project. The IS/MND contains no baseline conditions for any impact.

The Project description fails to identify the crudes that would be imported, the crudes that would be displaced, all of the key chemical composition data required to

[1] ESA, Valero Crude by Rail Project, Initial Study/Mitigated Negative Declaration, Use Permit Application 12PLN-00063, Prepared for City of Benicia, May 2013.

assess crude quality and resulting impacts, and Project process flow diagrams and design documents essential to assess impacts. In short, the IS/MND fails to provide a meaningful description of the Project. The number and nature of the deficiencies are so substantial that the IS/MND should be withdrawn and replaced with a draft EIR with a complete Project description and a thorough environmental impact analysis.

My resume is included in Attachment 1 to these comments. I have over 40 years of experience in the field of environmental engineering, including air emissions and air pollution control; greenhouse gas emission inventory and control; air quality management; water quality and water supply investigations; hazardous waste investigations; environmental permitting; nuisance investigations (odor, noise); environmental impact reports, including CEQA/NEPA documentation; risk assessments; and litigation support.

I have a M.S. and Ph.D. in environmental engineering from the University of California at Berkeley with minors in Hydrology and Mathematics. I am a licensed professional engineer (chemical, environmental) in five states; a Board Certified Environmental Engineer, certified in Air Pollution Control by the American Academy of Environmental Engineers; and a Qualified Environmental Professional, certified by the Institute of Professional Environmental Practice.

I have prepared comments, responses to comments and sections of EIRs for both proponents and opponents of projects on air quality, water supply, water quality, hazardous waste, public health, risk assessment, worker health and safety, odor, risk of upset, noise, land use and other areas for well over 100 CEQA documents. This work includes Environmental Impact Reports (EIRs), Negative Declarations (NDs), and Mitigated Negative Declarations (MNDs) for all California refineries as well as various other permitting actions for tar sands refinery upgrades in Indiana, Louisiana, Michigan, Ohio, South Dakota, Utah, and Texas. My work has been cited in two published CEQA opinions: (1) *Berkeley Keep Jets Over the Bay Committee, City of San Leandro, and City of Alameda et al. v. Board of Port Commissioners* (August 30, 2001) 111 Cal.Rptr.2d 598 and *Communities for a Better Environment v. South Coast Air Quality Management Dist. (2010) 48 Cal.4th 310*.

Ian Goodman and Brigid Rowan of The Goodman Group, Ltd. (TGG) are also submitting Comments on IS/MND (TGG Comments) and specifically are undertaking an evaluation of crude supply. I have relied on their report in my analysis. I conferred with TGG (Ian Goodman) during the preparation of our respective Comments, and (where relevant), each of the Comments makes reference to the other.

II. AIR EMISSIONS WOULD INCREASE DUE TO CHANGES IN CRUDE QUALITY

The Project will allow the Refinery to replace up to 70,000 barrels per day (BPD) of crude oil currently transported by marine vessel with an equivalent amount of crude oil transported by rail. MND, p. 1; IS, p. I-1. The crude oil imported by rail is identified

only as "North American-sourced crude oil" that is "expected to be of similar quality compared to existing crude oil imported by marine vessels." MND, p. 1; IS, p. I-1. The specific "North American-sourced crude oils" are not identified. As discussed below, all crudes are not created equal.

The IS/MND also asserts that imports by rail would not displace crude delivered by pipeline (heavy sour San Joaquin Valley crudes), would not result in an increase in the production of existing products or byproducts, and would require no modification to Refinery process equipment. MND, p. 1, IS, p. I-1. However, the Initial Study does not contain any of the information required to evaluate these claims and their resulting environmental impacts. In fact, key project description and emissions data required to assess this claim and resulting environmental impacts are claimed as confidential (ATC, Appx. A, Appx. B (Attachs. B-1, B-2, B-4)), preventing meaningful public review. Further, the MND does not recommend any conditions that would assure these fundamental (and undisclosed) assumptions are in fact implemented. The MND, for example, does not limit the quality of the rail imports, the origin of the rail imports, nor the quality of displaced ship imports. These are serious flaws as crude quality determines environmental impacts, as explained elsewhere in these comments.

The emissions from a refinery depend upon the composition of the crude that it refines. The Initial Study indicates the Refinery currently processes a blended slate of crude oil with a gravity that ranges from 20° to 30° API[2] and a sulfur content that ranges from 0.6% to 1.9%, based on 2011 to 2012 data. IS, pp. I-2, I-6. However, nothing else about this crude slate is disclosed. The undisclosed information determines the environmental impacts.

The Initial Study also asserts that the "North American-sourced crude oils are expected to replace crude oils of similar gravity and sulfur content currently brought in by ship," reporting the rail imports to have a gravity that ranges from 20° to 43.5^o API and a sulfur content that ranges from 0.06% to 3.1%. IS, pp. I-2, I-6. Thus, the Initial Study concludes that "it is anticipated that the Refinery would continue to operate within its existing specifications for crude oil gravity and sulfur content range." *Ibid.* Further, it concludes that the Refinery would not need to change existing operations or process equipment, "nor would emissions from Refinery operations change (with the exception of the storage tank service and rail unloading emissions) as a result of accepting and refining the proposed North American-sourced crudes." IS, pp. I-2, I-6, I-7. These conclusions are unsupported and likely wrong.

First, the ability of a refinery to process a particular crude and the resulting emissions depend upon many more variables than just the API gravity and sulfur

[2] The specific gravity of crude oil is typically measured using the American Petroleum Institute (API) standard or the API gravity of the crude oil. The API gravity is a measure of the weight of crude oil in relation to the weight of water (which has an API gravity of 10 degrees). Heavy crude oil has an API gravity of 18° or less. The oil is viscous and resistant to flow. Intermediate crude has an API greater than 18° but less than 36°. Light crude has an API gravity of greater than 36°.

content.[3] Valero certainly knows this and could not evaluate crudes to include in its swap without substantially more information than disclosed in the IS/MND. The same information Valero uses to select crudes is required to assess environmental impacts. This critical information is missing from the record. The public has been left in the dark to guess what the crude quality and thus impacts might be. This contravenes the information disclosure requirements of CEQA. There are major chemical differences between the crudes currently imported by ship and available "North American-sourced crude oils" that could only arrive by rail.[4]

Second, the range of two crude characteristics does not reveal anything about the median and average value of those parameters, which ultimately determine emissions. The sulfur content of the crude slate, for example, could continue to fluctuate between 0.6% to 1.9% while the average sulfur content of the slate could creep up, which has in fact happened at California refineries[5] as well as elsewhere.[6]

Third, the IS/MND does not include any conditions of certification that would prevent the selection of any North American-sourced crude available by rail, either currently or in the future. Many such crudes have unique chemical characteristics that would result in significant environmental impacts not disclosed in the IS/MND. As discussed elsewhere in these comments, the Refinery is in the process of being modified to allow it to process a larger amount of also unidentified heavy high sulfur crudes, which Valero admits would increase the sulfur content of the crude and make it heavier. The refining of many of these crudes would result in significant environmental impacts. In fact, the most economically attractive heavy high sulfur crudes, those derived from Canadian tar sands bitumens, are only available in large quantities to the Refinery by rail. Thus, absent conditions of certification to the contrary, it is possible that a rail terminal would allow the import of heavy high sulfur crudes in the future, after the current

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[3] See, for example, CCQTA, Canadian Crude Oil Quality Past, Present and Future Direction, February 7, 2012, pp. 8 ("Need more than sulfur and gravity to determine the "acceptability and valuation" of crude oil in a refinery. The crude oil's hydrocarbon footprint and contaminants determine the value of crudes.."), Available at: http://www.choa.ab.ca/index.php/ci_id/9210/la_id/1/, provided as Appendix I to TGG Comments.

[4] D. Stratiev and others, Evaluation of Crude Oil Quality, Petroleum & Coal, v. 52, no. 1, pp. 35-43, 2010, Available at: http://www.vurup.sk/sites/vurup.sk/archivedsite/www.vurup.sk/pc/vol52_2010/issue1/pdf/pc_1_2010_stratiev_051.pdf. See also www.crudemonitor.ca.

[5] Margaret Sheridan, California Crude Oil Production and Imports, California Energy Commissions Staff Paper, April 2006.

[6] EIA, Crude Oil Input Qualities, Available at: http://www.eia.gov/dnav/pet/PET_PNP_CRQ_A_EPC0_YCS_PCT_M.htm; Greg L. Armstrong, Crude Oil Trends & Recent Developments, January 11, 2012, pp. 19-20, Available at: http://www.ipaa.org/meetings/ppt/2012TIPRO/January/012012-Armstrong.pdf and Edward J. Swain, Sulfur, Coke, and Crude Quality - Conclusion U.S. Crude Slate Continues to Get Heavier, Higher in Sulfur, Oil & Gas Journal, January 9, 1995, Available at: http://www.ogj.com/articles/print/volume-93/issue-2/in-this-issue/refining/sulfur-coke-and-crude-quality-conclusion-us-crude-slate-continues-to-get-heavier-higher-in-sulfur.html.

modifications are complete, that would increase emissions relative to the current baseline, causing significant undisclosed environmental impacts.

This would be consistent with statements in the IS/MND that rail imports are "expected to be of similar quality compared to existing crude oil imported by marine vessels." MND, p. 1; IS, p. I-1. Further, many of the tar sands crudes fall within the range of API gravity and sulfur content reported in the IS/MND, from 20° to 43.5^{o} API and a sulfur content that ranges from 0.06% to 3.1%. IS, pp. I-2, I-6. Crude oil import data reported by Valero to the U.S. Energy Information Administration (EIA) and discussed below indicate that the Refinery is currently importing Canadian tar sands crudes.

Thus, without crude assay data and conditions of certification that restrict crude quality to that analyzed in the CEQA documents, and at least annual reporting to assure compliance, the Refinery has the discretion to import any crude that is cheaper, regardless of environmental impacts. This could include heavy sour Canadian tar sands crudes. As discussed elsewhere in these comments, heavy sour Canadian tar sands crudes are a worst case for environmental impacts. They would increase air emissions and result in other significant impacts, relative to the current baseline, that were not considered in the IS/MND.

A. Related Projects Not Disclosed

Valero is currently in final phases of constructing the Valero Improvement Project or VIP, which will not be fully operational until the end of 2014. The Crude by Rail Project should be evaluated in the context of the VIP FEIR, not through an isolated IS/MND that fails to even disclose this precedent, related project that it is modifying.

The VIP is designed to facilitate the import and processing of much higher sulfur and heavier crudes than the current slate, The VIP would permit the Refinery to process heavier, high sulfur feedstocks as 60% of total supply, up from just 30% prior to the VIP.[7] The VIP has been permitted and is in the final stages of construction. VIP DEIR 2002.[8] The VIP project includes the following elements that are designed specifically to allow a shift to a much lower quality crude slate:

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[7] VIP DEIR, p. 3-20 ("The refinery currently imports and processes two primary raw materials – crude oil and gas oil. Currently, about 30% of the refinery feedstocks are lower-grade raw materials, with higher levels of sulfur and higher heavy pitch content. The VIP changes would allow the refinery to purchase and process additional volumes of lower-grade raw materials (crude oils or gas oils). In general terms, the refinery would be able to increase this percentage to about 60%, raising the average sulfur content of the imported raw materials from current levels of about 1 - 1.5% up to future levels of about 2 - 2.5%.").

[8] ESA, Valero Refining Company's Land Use Application for the Valero Improvement Project, Environmental Impact Report, Draft, October 2002 (DEIR), The Benicia Planning Commission certified the Final EIR, consisting of the DEIR and the Responses to Comments in Resolution No. 03-4. This FEIR was amended in 2007. Supporting documents available at:

- Pipestill (crude unit) modifications to increase crude oil processing capacity from 135,000 BPD to 165,000 BPD, or by approximately 25% (VIP DEIR, p. 3-27);
- Fluid Catalytic Cracker Unit Feed Flexibility modifications to process different feeds and increase process rate from 72,000 BPD to 75,000 BPD or higher on occasion (VIP DEIR, p. 3-28; VIP Amend., p. 2-21);
- Coker Unit modifications from 30,000 BPD to 35,000 BPD (VIP DEIR, p. 3-30);
- Increased refinery capacity to remove and recover sulfur from 320 ton/day to 480 ton/day (VIP DEIR, p. 3-33)
- Flue Gas Scrubber to reduce emissions from the main stack (VIP DEIR, Sec. 3.4.3.5);
- Increase hydrogen production from 160 to 190 MMscf/day to support hydrofining and hydrocracking (VIP DEIR, p. 3-39);
- Hydrofining optimization changes (VIP DEIR, Sec. 3.4.3.7);
- Modifications to maximize hydrocracking, alkylation, and reforming capacity (VIP DEIR, Sec. 3.4.3.8);
- Adding a Guard Reactor to the Hydrotreater (VIP DEIR, Sec. 3.4.3.9);
- Modifications to optimize fractionation processes (VIP DEIR, Sec. 3.4.3.10);
- New and modified existing combustion sources (VIP DEIR, Sec. 3.4.3.11);
- Use of 150 gpm of additional water (VIP DEIR, Sec. 3.4.3.12);
- Modifications to the wastewater treatment facility (VIP DEIR, Sec. 3.4.3.13);
- An additional desalter vessel to remove salts and solids (VIP Adden., Table 2.1.1-1);
- Added support facilities and infrastructure (VIP DEIR, Sec. 3.4.3.14);
- Added new crude tankage (VIP DEIR, Sec. 3.4.3.15);
- Increased import and export ship and train traffic (VIP DEIR, Sec. 3.4.3.16).

These are the types of modifications that would be required to increase the amount of heavy sour crude processed at the Refinery. These modifications were

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http://www.ci.benicia.ca.us/index.asp?Type=B_BASIC&SEC=%7B737165B4-11C5-4974-9B0B-0AE4AC535ECC%7D.

estimated to increase electricity demand by 23 MW[9] and natural gas consumption by 9.6 MMscf/day. (VIP DEIR, pp. 2-3). They were also estimated to increase the firing rate of heaters and boilers throughout the Refinery by 400 MMBtu/hr (VIP DEIR, p. 3-47)[10]. These increased utility demands increase emissions.

They also would have other adverse impacts not disclosed in the VIP FEIR that must be disclosed in the Crude by Rail Project. Most of the modifications have started up. However, the last major part of the VIP project, the Hydrogen Plant, the critical link required to tie the rest of the Project together, is not estimated to startup until the end of 2014. Valero filed a request with the BAAQMD to extend the construction permit for the Hydrogen Plant through December 2014 to accommodate this delay.[11]

The VIP was specifically designed to allow the Refinery to shift to a much heavier, higher sulfur crude slate. The subject crudes would have sulfur contents up to 4% and would require heated tanks for storage.[12] These are "heavy sour crudes". There are only a few crudes with these characteristics that might meet Valero's other goal of lowering the cost of petroleum feedstocks. VIP DEIR, pp. 3-32, 3-35. As further

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[9] Increased by 1.5 MW in 2007 with the addition of a new desalter. VIP Environmental Analysis, September 2007, p. 2-21.

[10] In the 2007 amendment, reduced by 100 MMBtu/hr by installing a new, more efficient Hydrogen Unit than originally planned for in the 2003 VIP FEIR and increased by 70 MMBtu/hr to facilitate FCCU modifications. VIP Environmental Analysis, September 2007, pp. 2-18, 2-21.

[11] ENSR Corporation, Environmental Analysis, Valero Improvement Project Amendments, September 2007 (2007 Amendments), Table 2.5.1-1 and VIP Semi-Annual Construction Report for the first half of 2012 - Revised, August 1, 2012 (showing the Hydrogen Plant starting up 4th quarter of 2014).

[12] VIP DEIR, pp. 1-1 (The purpose of the VIP is to allow the Refinery to process certain "lower grades of raw material" (crude oil and gas oil), 3-16 ("lower grade of crude"), 3-28 (the FCCU would be modified to allow it to "develop the flexibility to process heavier feedstocks.."), 3-30 ("[a] key characteristic of the new petroleum crude blends to be processed...is a higher percentage of heavier hydrocarbons than in the crude mix now processed.."), 3-32 ("the VIP would enable the refinery to process lower cost petroleum feedstocks (crudes) that could contain up to twice the sulfur content of the crudes presently processed at the refinery."), 3-35 ("[t]he VIP modifications to the refinery would enable the processing of additional lower cost heavy petroleum feedstocks (crudes) with higher sulfur. One characteristic of these crudes is that they could contains about 4% sulfur, up to twice the average sulfur content of the crudes presently processed at the refinery. Though these crudes are not necessarily new to the refinery, there would be more of them processed."), 3-45 (with the changes in feed stock characteristics anticipated after the VIP modifications..."), 3-46 ("The VIP would require more heat provided by combustion because more oil products will be processed than at present and because the VIP new crude blends will consist of heavier components which require more heat for processing...than the present crude blend."), 3-49 ("Several tanks that would store heavy feedstocks would need to be fitted with steam heating equipment. By heating the heavy oil, the viscosity would be reduced enough to allow more efficient pumping."), 4.2-19 ("The VIP proposes to process a higher percentage of lower grades of crude oil with greater sulfur content than it presently can process."), 4.5-3 (The project would...allow lower grade materials to be refined there."), p. 4.8-10 ("[t]he lower grade crude oils expected in the project..."), 4.8-11 ("heavier crude feedstocks", "heavier feedstock", "feedstock changes"), 4.8-14 (there will be about three additional ships per month for crude oil transport and a reduction of two barges and ships for gas oil transport."), 8-4 ("Valero proposes to develop the capability to economically process additional heavy crudes and crudes with more sulfur on average than those processed at the refinery since 1970.").

discussed in TGG Comments and Section C below, Canadian tar sands are the most proximate and cost effective option to achieve Valero's goals for the Benicia Refinery.[13]

Thus, clearly, Valero is in the process of implementing a major expansion project to allow it to process increased amounts of heavy sour crude, consistent with the composition of Canadian tar sands crudes. The VIP is nearly complete. The last component, a new Hydrogen Plant, is scheduled to startup at the end of 2014. An increase in hydrogen is essential to refining increased amounts of heavy sour crude. Thus, the anticipated increase in heavy sour crude has not yet occurred. This is confirmed by the U. S. Energy Information Administration (EIA) crude import data,[14] which shows only a tiny amount of heavy sour (>3.5%) crudes delivered to Benicia. The EIA crude import data for 2010 to 2012 indicate 0.5% to 2% of the crude slate originated in Canada with an API gravity (20.8^{o}-22.6^{o}) and sulfur content (3.54%-3.75%) consistent with Canadian tar sand crudes.[15]

Thus, for purposes of CEQA analysis, the baseline for the Crude by Rail Project is the period 12/10/10 to 12/9/12 (IS, p. I-6), a period when very little Canadian tar sands crude was being processed. The Crude by Rail CEQA analysis must evaluate impacts relative to physical conditions as they existed during this period. The IS/MND assumes the proposed crude switch could occur without any change to Refinery process equipment or increases in production of existing products or byproducts. IS, p. I-1. This would likely be feasible if full buildout of the VIP is assumed as the baseline.

B. All Increases In Emissions Must Be Considered Under CEQA

The IS/MND fails to disclose or quantify the increases in emissions that could result from modifying the crude slate. However, replacing 70,000 BPD or 81% of its ship imports or nearly half (70/165 = 0.43) of its entire current crude slate with tar sands crudes in the long term would make the overall slate heavier, increase emissions, and result in significant environmental impacts.

The use of the proper CEQA baseline is critical to accurately evaluate impacts. The Refinery operates under a permit issued by the Bay Area Air Quality Management District (BAAQMD). This permit establishes maximum amounts of regulated pollutants that can be emitted, including those permitted pursuant to the VIP. The Crude by Rail Project may result in increases in emissions that fall within the limits in this and other permits and plans, such as the VIP FEIR and still result in significant impacts. Permit limits and conditions of certification in previous CEQA actions do not establish the baseline for purposes of the CEQA review for the Crude by Rail Project.

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[13] See, for example, Stratiev et al. 2010, Table 1 and Wikipedia, List of Crude Oil Products, Available at: http://en.wikipedia.org/wiki/List_of_crude_oil_products.

[14] EIA, Petroleum & Other Liquids, Company Level Imports, Available at: http://www.eia.gov/petroleum/imports/companylevel/.

[15] www.crudemonitor.ca.

A long line of Court of Appeal decisions and a California Supreme Court decision hold that impacts of a proposed project are 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, such as the BAAQMD permit or the VIP FEIR. The California Supreme Court specifically concluded, in a case that I worked on involving the ConocoPhillips refinery in Los Angeles, that the pre-existing permits did not establish the baseline for CEQA analysis. *(2010) 48 Cal.4th 31.*

Thus, while the emission increases identified below may well fall within existing Permit limits, this does not exclude them from CEQA review for the Crude by Rail Project. The increases in emissions that will occur from importing "North American-sourced crudes" must be quantified and evaluated under CEQA as of current conditions, regardless of permit limits. The IS/MND does not do this. To the extent that these emissions were considered in the related VIP Project, these emissions and mitigations must be evaluated within the regulatory and other frameworks on the ground during the baseline period. Much has changed since the 1999 to 2001 baseline used to evaluate the VIP, which will be modified by the Crude-by-Rail project.

My analyses presented below indicate that these increases would be significant, would exceed BAAQMD CEQA significance thresholds and potentially would contribute to adverse health impacts, malodors, and major accidental releases, as well as degradation of ambient air quality. The IS/MND is silent on these potential emission increases and their environmental consequences. My analysis indicates these impacts are significant and unmitigated, requiring the preparation of an EIR.

C. What Crude Will Be Imported By Rail?

Refining generates emissions. The type and amount of emissions depend upon the chemical characteristics of the specific crudes included in the slate. The central question that must be answered to determine environmental impacts of the Crude by Rail Project is what crude(s) will be imported by rail, and what crude(s) will replace them, for the life of the Project. This is not disclosed in the IS/MND, presenting a mystery for reviewers.

In fact, the IS/MND goes to great lengths to not identify the crudes that would be imported, quoting only ranges in two parameters -- sulfur content and API gravity -- which are irrelevant to potential impacts. The IS/MND claims nothing would change except the mode of transportation, from ship to rail. It ignores all impacts related to the crude itself. Thus, the IS/MND is asserting a claim that is inconsistent with the massive refinery upgrade and expansion currently underway. The VIP heavy sour crude expansion would not be built if Valero was really planning to sweeten and lighten up its crude slate. Further, the IS/MND claims as confidential all information that one could potentially use to identify these crudes, including crude quality data, process flow diagrams, and critical support for the emission calculations. ATC, Appx. A, B.

1. The IS/MND Crude By Rail Project Is Inconsistent With The VIP Project

As explained above, the Refinery is being extensively modified to allow it to process increased amounts of heavy sour crudes, consistent with Canadian tar sands crudes. However, the IS/MND asserts the opposite. The VIP was specifically designed to allow the Refinery to increase the amount of heavy sour crudes in its slate, up to 60% of the total. [16] Valero characterized the VIP as a "crude 'sour-up'" to reduce dependence on ANS.[17] With the VIP fully operational, this Refinery could process approximately 100,000 BPD of heavy sour crudes. [18] Thus, the full 70,000 BPD capacity of the Crude by Rail Project could be used for heavy sour crudes.

Meanwhile, as of 2010, Valero stated that it had the ability to process 35% heavy sour crude, 47% medium/light sour crude, and 18% other.[19] or less than 60,000 BPD of heavy sour crude. So prior to completion of the VIP, this Refinery could process substantial amounts of heavy sour crudes, but much less than it will be able to in the near future. And once a Crude by Rail Project is in place, it could be used to deliver the heavy sour crudes that this Refinery can process.

The IS/MND does not even mention the VIP nor attempt to resolve this inconsistency.

Valero has applied to the Bay Area Air Quality Management District (BAAQMD) for a construction permit for the Crude by Rail Project. The Authority to Construct Application (ATC) is Appendix A to the IS/MND. In the BAAQMD proceeding, Valero responded to questions by the BAAQMD in an April 11, 2013 letter. In this letter, Valero repeatedly describes the crudes that would be imported as light sweet crudes that will cause the current slate to become "sweeter", "lighter in gravity and lower in sulfur than the average Padd V or average Valero crude slate," and as "ANS look-alikes or sweeter". (4/11/13 BAAQMD RTC).[20]

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[16] VIP DEIR, p. 3-20.

[17] Valero, Benicia Refinery Tour Slides, July 9, 2007, p. 26, provided as Appendix F to TGG Comments.

[18] IS p. I-1 ("The Refinery's crude oil processing rate is limited to an annual average of 165,000 barrels per day (daily maximum of 180,000 barrels per day) by Bay Area Air Quality Management District (BAAQMD) permit."). 60% of 165,000 BPD equals 99,000 BPD. Even if some of these heavy sour crudes are delivered by pipeline, most (if not all) of the crude by Rail could be heavy, sour. In the 2007-2010 period, the refinery received 20-25% of its crude by pipeline, so in the order of 25,000-35,000 BPD (Valero, Benicia Refinery Tour Slides, July 9, 2007, p. 26, provided as Appendix F to TGG Comments; Valero, Benicia Refinery Tour Slides, August 17, 2010, p. 29, provided as Appendix G to TGG Comments).

[19] Valero, Benicia Refinery Tour Slides, August 17, 2010, p. 29, provided as Appendix G to TGG Comments.

[20] Letter from Susan K. Gustofson, Valero to Thu Bui, BAAQMD, transmitting Crude by Rail Project, Response to BAAQMD 3/20/2013 Project Questions, April 11, 2013, Public Version, pp. 5 ("North American sourced crudes are typically characterized as "sweet" meaning they contain less than 0.5 wt% sulfur. The North American sourced crudes **currently** available to the Valero Benicia refinery are expected

This is exactly the opposite of claims in the VIP FEIR. It further is unlikely as a long-term strategy due to the physical changes that have been and are currently being made to the Refinery. Sourcing North American light sweet crudes by rail may be an interim strategy to boost profits while VIP construction is being completed, but it is not a likely or even credible long-term option. Using the Benicia Crude by Rail Project to deliver heavy, sour tar sands Dilbits is much more consistent with VIP, especially given the large capital investments that have already occurred, on-going construction of the VIP to allow more processing of heavy sour crudes, and the economic benefits of running these cheaper lower grade crudes.

Valero's response to the BAAQMD only asserts "[t]he North American sourced crudes **currently** available to the Valero Benicia refinery are expected to have sulfur below 0.5 wt%." Response to BAAQMD, p. 5. This says nothing about the future. The VIP project is currently incomplete. The Hydrogen Plant, which ties the VIP together and is essential to process increased amounts of heavy sour crude, will not be operational until the end of 2014. The Crude by Rail Project would be operational by the end of 2013 and would thus operate for about a year before the VIP would be fully operational.

Thus, it is conceivable that during this interim period, Valero would deliver increased amounts of a light sweet crude by rail, perhaps Bakken,[21] which may continue to be available at a cost that is competitive compared to other crudes in its current slate. Interim imports of Bakken may occur while sufficient export facilities are constructed in Canada to handle the large unit trains proposed for Benicia.[22] However, especially in the long term, the rail terminal could be used to import Canadian tar sands crudes planned for the VIP as the IS/MND does not propose any conditions of certification to limit rail import to only light sweet crudes. As further discussed in TGG Comments, the import of tar sands crudes is likely as the Refinery will have been upgraded to process them, and they are likely to be discounted relative to other crudes available to the Refinery. Alternatively, Valero could blend heavy sour tar sands crude with light sweet North American crudes, such as Bakken, to make a "pseudo" Alaskan North Slope (ANS)

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to have sulfur below 0.5 wt% which is well below the typical crude slate average of 1.4 wt%. Therefore, these crudes directionally sweeten the crude slate and reduce the amount of refinery fuel gas sulfur treatment required."), 6 ("...the crude slate is expected to be sweeter with the introduction of North American sourced crudes."), 7 ("North American sourced crudes are expected to be sweeter than existing average crude slate", "North American sourced crudes are characterized as sweet and are expected to have sulfur content lower than current crude slate sulfur average"), 8 ("The crudes proposed to be brought in by rail are those that fall into the lower right corner of the graph, which would be lighter in gravity and lower in sulfur than the average Padd V or average Valero crude slate."), 8 ("...the proposed North American sourced crudes are expected to be ANS look-alikes or sweeter...there is not expected to be any difference in emissions...compared to existing operations."), 9 ("North American-sourced crudes proposed to be received by railcar are ANS look-alikes or sweeter..").

[21] John R. Auers, The Prospects for Bakken Crude from a Refiners Perspective, November 16, 2010, Available at: http://turnermason.com/Publications/petroleum-publications_assets/Bakken-Crude.pdf.

[22] Sandy Fielden, Crude Loves Rock'n'Rail - Heat It! Bitumen by Rail (Part 2), March 19, 2013, Available at: http://www.rbnenergy.com/crude-loves-rocknrail-bitumen-by-rail-part-2.

substitute,[23] thus importing some of both. Regardless, tar sands crudes cannot be eliminated as a rail terminal import.

Further, even assuming the import of light sweet crudes to lighten up the slate, the Crude by Rail project would result in changes in emissions that were not considered in either the VIP FEIR or the instant IS/MND. For example, lighter crudes would increase emissions of VOCs and volatile hazardous organic pollutants (HAPs) from tanks, pumps, compressors, valves and connectors throughout the Refinery. These increases have not been evaluated in either the VIP FEIR nor the IS/MND.

Regardless, you cannot simultaneously lighten up and heavy up the crude slate and sour up and sweeten up the crude slate. It is either one or the other. The IS/MND does not disclose which it is, claiming it is neither, just the status quo without identifying the status quo. In the long-term, given the modifications to the Refinery, the most likely option is to import increased amounts of sour heavy Canadian tar sands crudes by rail. This option cannot be eliminated as the Refinery has been upgraded to handle these crudes and they will improve profit margins. Further, the worst case must be evaluated under CEQA absent conditions of certification prohibiting it.

Heavy sour crudes were anticipated to arrive by ship in the VIP, which assumed about three additional ships per month of heavy sour crude and two less barges and ships of gas oil. VIP DEIR, p. 4.8-14. The IS/MND, however, is contingent upon a comparable decrease in ship traffic. However, as further discussed in TGG Comments, due to delays in securing pipeline capacity and port facilities to export Canadian tar sands by ship, the only current way for Valero to take advantage of tar sands crudes and cost effectively deploy the VIP capital improvements is to import Canadian tar sands crudes by rail.

2. What Crudes Are Likely To Be Refined?

The first step in determining emission increases is to identify the crudes that are involved in the proposed switch. The crudes that the Refinery imported between 2007 and 2013 are summarized in Figure 1 from data reported by Valero to the EIA.[24] All of these crudes arrive by ship.[25]

Figure 1 shows that a small amount of crude currently arrives from Canada. The EIA composition data for this crude is consistent with heavy sour tar sands crudes. The puzzle that the IS/MND reviewer is left to unravel is which of these crudes will be

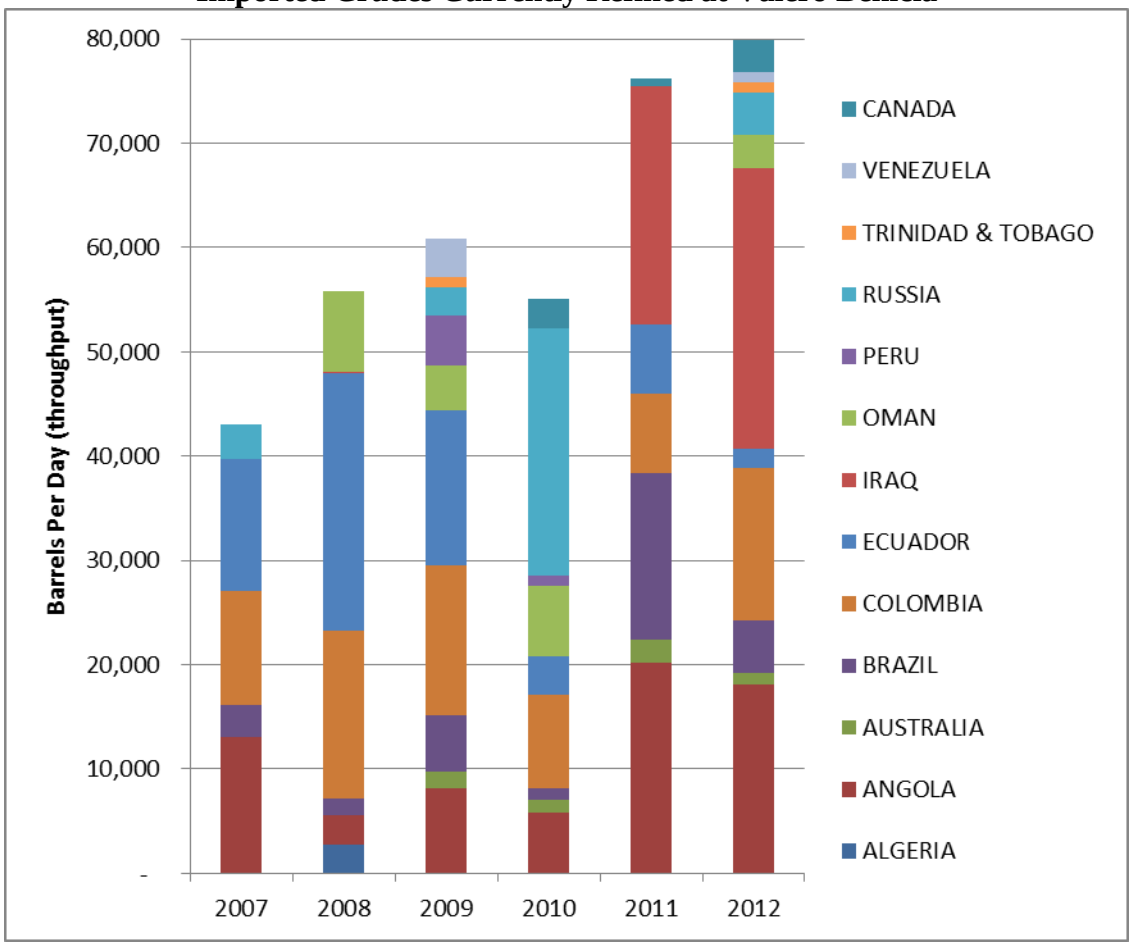
[23] John R. Auers and John Mayes, North American Production Boom Pushes Crude Blending, Oil & Gas Journal, May 6, 2013, Available at: http://www.ogj.com/articles/print/volume-111/issue-5/processing/north-american-production-boom-pushes.html.

[24] EIA, Petroleum & Other Liquids, Company Level Imports, Available at: http://www.eia.gov/petroleum/imports/companylevel/.

[25] In addition to these imports by ship, the Refinery also processes some domestic crudes, including ANS (which arrives by ship) and California crudes (which arrive by heated pipeline).

replaced by "North American-sourced crudes" and what "North American-sourced crudes" will do the replacing. The IS/MND contains none of the information needed to solve this puzzle and thus is inadequate.

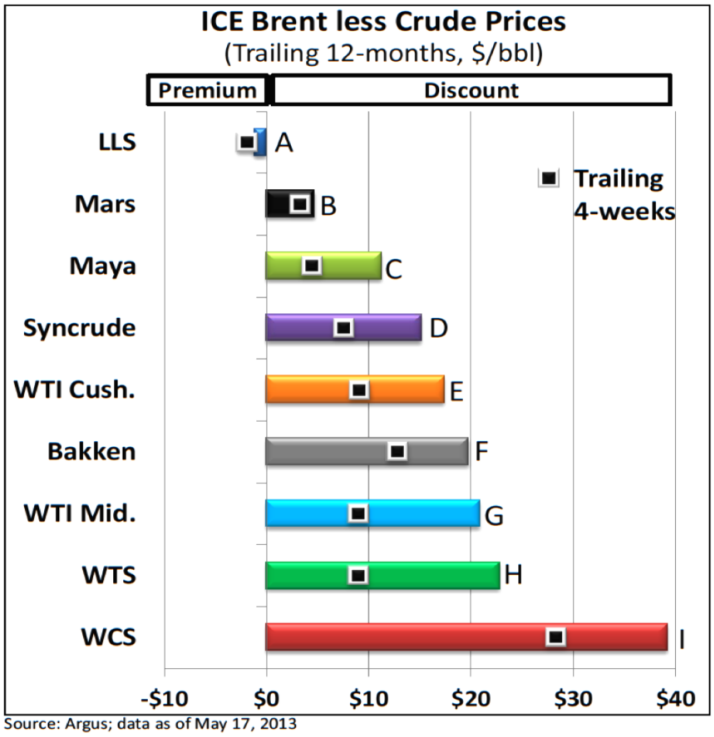
Figure 1
Imported Crudes Currently Refined at Valero Benicia



A recent presentation by Valero indicates that it plans to import "cost-advantaged crude oil" to its Benicia refinery.[26] This is consistent with the VIP, which is designed to allow the Refinery to process increased amounts of cheaper heavier sourer crudes. The cost-advantaged crude oils identified by Valero are shown in Figure 2.

[26] Valero, UBS Global Oil and Gas Conference, May 21-22, 2013, p. 10, Available at: http://www.valero.com/InvestorRelations/Pages/EventsPresentations.aspx. provided as Appendix D to TGG Comments.

Figure 2
Cost-Advantaged Crudes
That Could Be Imported By Rail[27]



The largest growth in cost-advantaged crudes is coming from U.S. shale crudes and heavy Canadian tar sands crudes, both of which are "North American-sourced crude

[27] **Brent** is light sweet crude oil sourced from the North Sea, priced at export point there. It has an API gravity of 37.9° and 0.45% sulfur. **LLS** is light Louisiana sweet, priced at St. James, LA. It has an API gravity of 37.0° and 0.38% sulfur. **MARS** is a medium sour blended crude marketed into the Gulf coast and mid-continent regions, priced at Clovelly LA. It has an API gravity of 28.7° and 1.8% sulfur. **Maya** is a heavy sour crude oil from Mexico, priced at export point there. It has an API gravity of 22° and 3.3% sulfur. **WTI Cush.** is West Texas Intermediate crude priced at Cushing, OK, a major trading hub for crude oil. It is a light crude oil with an API gravity of 39.0° and 0.4% sulfur (see also http://en.wikipedia.org/wiki/West_Texas_Intermediate). **WTI Mid**. is West Texas Intermediate (API gravity of 39.0° and 0.4% sulfur) priced at Midland TX (proximate to Permian Basin production). **WTS** is west Texas Sour priced at Midland, TX and an API gravity of 33.5° and 1.9% sulfur. **Syncrude** is a light sweet synthetic Canadian tar sands crude consisting of a bottomless blend of hydrotreated naphtha, distillate, and gas oil fractions produced from a coker and hydrocracker based upgrader facility in Canada; priced at Edmonton Alberta. It typically has an API gravity of 31.0° to 33.0° and 0.1% to 0.2% sulfur (see also http://www.crudemonitor.ca/crude.php?acr=SYN). **WCS** is Western Canadian Select, priced at Hardesty, Alberta. This is a tar sands DilBit crude with API gravity of 20.0° to 21.0° and 3.4% to 3.7% sulfur (see also http://www.crudemonitor.ca/crude.php?acr=WCS).
Sources: Valero crude price data (in Figure 2) are sourced to Argus, so crude specifications in this footnote are based on Argus Methodology and Specifications: Americas Crude (Last Updated: May 2013) http://media.argusmedia.com/~/media/Files/PDFs/Meth/argus_americas_crude.pdf and (for Brent) Argus Crude (Updated: June 2013) http://media.argusmedia.com/~/media/Files/PDFs/Meth/argus_crude.pdf
The pricing locations specified are those shown in Valero, UBS Global Oil and Gas Conference, May 21-22, 2013, p. 8, Available at: http://www.valero.com/InvestorRelations/Pages/EventsPresentations.aspx, provided as Appendix D to TGG Comments.

oils." The puzzle then is to figure out which of the cost-advantaged crudes in Figure 2 that Valero would import to Benicia by rail and which of the crudes currently imported by ship, shown in Figure 1, would be replaced. Due to the paucity of information, only a first order guess is possible. The IS/MND is deficient for placing the burden on the reviewer of piecing together Valero's plans.

The Canadian tar sands crudes (except the syncrudes) are heavy sour crudes while the U.S. shale crudes are light sweet crudes. The modifications to the Refinery made under the VIP set it up to process increased amounts of heavy sour crudes, not the light sweet crudes such as those from U.S. shale crudes. Thus, the light sweet shale crudes are unlikely to be the long-term choice. However, in the interim, before the VIP is implemented, it is possible that light sweet shale crudes would be imported to bridge the gap between bringing the entire VIP on line and fuller build out of unit train loading terminal capacity in Canada.[28] This is confirmed by the economics of the plays.

Valero's list of cost-advantaged crudes in Figure 2 indicates that the most cost-advantaged crude is Western Canadian Select (WCS),[29] which is Canadian tar sands bitumen diluted to pipeline specifications with 25% to 30% diluent or a "DilBit." I refer to these DilBit crudes in these comments as tar sands crudes. The diluent is typically natural gas condensate, pentanes, or naphtha.[30] Most of the tar sands crudes are too heavy to flow in a pipeline. Thus, they must be diluted or thinned with a lighter hydrocarbon stream to reduce viscosity and density to meet pipeline specifications. More diluent is required in the winter than summer to maintain flow rates during cold weather. The IS/MND and VIP FEIR are silent on the presence, composition and emissions from this diluent. However, the potential rail import of DilBits cannot be eliminated and is the most likely rail import due to economic considerations. The failure to disclose the potential import of tar sands crudes is a significant omission as the emissions from handling this material are large and significant.

As further discussed in TGG Comments, tar sands crudes are produced in Northern Alberta, which is landlocked and remote from the refineries that can process these crudes. Compared with other potential markets for these crudes, California is relatively proximate and has refineries configured to process heavy sour crudes. Transportation costs from Alberta to California may thus be low enough to make the delivered cost of tar sands crudes attractive for California refineries.

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[28] Fielden, March 19, 2013.

[29] Cenovus Energy, Western Canadian Select (WCS) Fact Sheet, Available at :http://www.cenovus.com/operations/doing-business-with-us/marketing/western-canadian-select-fact-sheet.html. See also CrudeMonitor.ca - Canadian Crude Quality Monitoring, Available at: http://www.crudemonitor.ca/crude.php?acr=WCS.

[30] Gary R. Brierley, Visnja A. Gembicki, and Tim M. Cowan, Changing Refinery Configurations for Heavy and Synthetic Crude Processing, Available at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BA07DE342-E9B1-402A-83F7-36B18DC3DD05%7D&documentTitle=5639138.

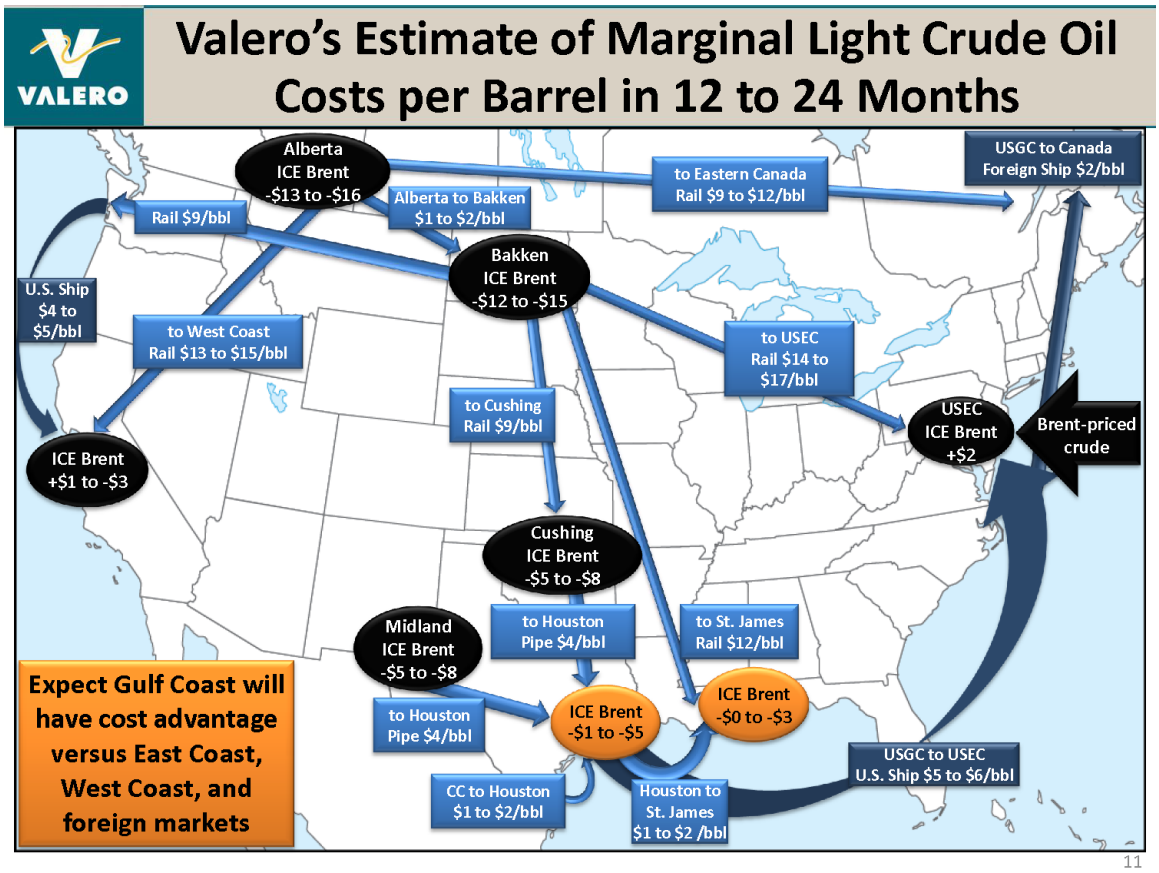
Figure 2 shows the most cost-advantaged crude is WCS, or a DilBit, which sells for a discount of nearly $40/bbl compared to ICE Brent.[31] Assuming Valero's reported light crude rail delivery cost of $13/bbl to $15/bbl,[32] WCE would arrive at Benicia at a discount of $23/bbl to $25/bbl relative to ICE Brent. Rail delivery costs for heavy crude would be somewhat higher, and heavy, sour crudes are less valuable than Brent (the global benchmark for light, sweet crudes). Still, the price of WCS delivered to Benicia may is likely lower (and very likely competitive), compared with all the other cost-advantaged crudes (Fig. 2). Thus, the most likely crude that Valero will import by rail at Benicia after the VIP is fully implemented is one of the tar sands crudes. The API gravity and sulfur content of these crudes are consistent with those projected in the VIP FEIR and fall within the ranges reported in the IS/MND.

The cost advantage to delivering North American-sourced light sweet crudes by rail is less than for tar sands crudes. The North American light crudes are discounted less relative to conventional light sweet crudes (ICE Brent) due to North American light crudes having more desirable qualities and being less relatively proximate to Benicia. These include marginal light crude oils from Alberta, Bakken, and Texas. The cost advantage of these crudes may be small (or completely disappear) after adding the cost of transport by rail to Benicia. This is demonstrated by Valero's analysis summarized in Figure 3.

[31] Brent crude is a major trading classification of sweet light crude oil sourced from the North Sea. Brent is the leading global price benchmark for Atlantic basin crude oils and is used to price two thirds of the world's internationally traded crude oil supplies. It contains about 0.37% sulfur and has an API gravity of 38.06°. It is traded on the electronic IntercontinentalExchange, know as ICE. See: http://en.wikipedia.org/wiki/Brent_Crude.

[32] Valero, May 21-22, 2013, p. 11, provided as Appendix D to TGG Comments.

Figure 3
Valero's Estimate of Marginal Light Crude Oil Costs per Barrel



The Bakken crude, for example, the closest U.S. cost-advantaged crude, is reported by Valero at a discount of $12/bbl to $15/bbl relative to ICE Brent. (Fig. 3). Valero indicates it would be sent by rail ($9/bbl) to an undisclosed port in Washington and then by ship to Benicia ($4/bbl to $5/bbl). The delivered cost at Benicia would be $1/bbl to $2/bbl **highe**r than ICE Brent if the initial crude discount relative to ICE Brent were $12/bbl. It would be -$1/bbl to -$2/bbl lower if the discount relative to ICE Brent were -$15/bbl.

Even if the delivered cost of Bakken into the California market would be slightly above Brent, this might still provide some savings to refiners, relative to the delivered costs of other crudes. The competitive position of Bakken (and other crudes) will depend in part on the pricing dynamics in the crude markets,[33] and also how specific refineries are configured.[34]

[33] Crude pricing is highly dynamic and varies in part based on crude flows. To the extent that California (and other North American coastal markets) are importing Brent and other waterborne crudes, delivered costs typically include a small premium to cover the cost of importing the crudes by tanker. In Valero's analysis in Figure 3, Brent-priced crude is assumed to be imported into East Coast US (PA/NJ), with the

The delivered cost of Alberta light Syncrude would be slightly more favorable. As reported by Valero, Syncrude is at a discount of $15/bbl relative to ICE Brent. (Fig. 2). And as previously noted, Valero indicates it would be sent by rail ($9/bbl) to an undisclosed port in Washington and then by ship to Benicia ($4/bbl to $5/bbl). The delivered cost at Benicia would be $1/bbl to $2/bbl below ICE Brent. However, the Benicia Refinery is not designed to process this crude and likely could accept only a small amount of it, much less than 70,000 bbl/day.[35]

Thus, it is unlikely that Valero would import light sweet crudes by rail if it were feasible to process the cheaper WCS tar sands crude. In the short term, through at least the end of 2014, when the VIP Hydrogen Plant goes on line, it may not be feasible to refine large amount of the WCS tar sands crudes. Thus, in the short-term, some of these light sweet shale crudes may very well be sourced to improve profits. However, the long term prospects for these light sweet crudes are more uncertain, given the discount of tar sands crudes and the physical modifications to the Refinery.

My following comments on environmental impacts of the Crude by Rail Project assume up to 100% DilBit tar sands crudes would be imported, as they represent a worst case for air emissions. However, 100% tar sands bitumen, Alberta Syncrude and light sweet shale crudes cannot be eliminated as part of a future potential mix of "North American-sourced crude" for the Refinery. It is impossible to identify what that mix might be, given the inadequate Project description. As impacts will be significant, regardless of the mix, an EIR should be prepared to evaluate the impacts of the full range of likely future imports.

The Project description suggests that undiluted bitumen would not be imported but it also suggests only light sweet material would be imported. To import undiluted bitumen, the railcars would have to be insulated to prevent the bitumen from solidifying in cold weather and equipped with steam-coils to re-heat the bitumen at Benicia for

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delivered price there at a $2 premium over Brent. Market analysis typically assumes that overseas tanker delivery (e.g., from Brent to East or Gulf Coast) costs about $2/barrel.

[34] Bakken and other light, sweet shale crudes are especially attractive for less complex refineries that are configured for light, sweet crudes, as opposed to more complex refineries that can process heavier, sour feedstocks.

[35] Ebullated Bed Hydroprocessing's Role in Bitumen Upgrading, Refinery Operations, July 20, 2011, p. 3, Available at: http://refineryoperations.com/downloads/refinery-operations_2-14_2011-07-20.pdf; Gerald W. Bruce, Bitumen to Finished Products, Canadian Heavy Oil Association Technical Luncheon, November 9, 2005, See pages captioned: Processing SCO and SCO Challenges, Available at: http://www.powershow.com/view/7004d-OGExM/Bitumen_to_Finished_Products_Presented_by_Gerald_W_Bruce_Jacobs_Canada_Inc_Canadian_Heavy_Oil_.Ass_powerpoint_ppt_presentation; Chris McManaman, The Major Challenges Facing the Future of Oil Sands Development, ("While SCO commands a premium price to WTI and is in many ways comparable to light sweet crude, the high aromaticity of bitumen from which it is derived limits its penetration into refineries that are not specially equipped to handle it. A typical refinery is limited to between 10-20% of SCO in its crude slate"), January 17, 2008, Available at: http://gembaoilsands.blogspot.com/2008/01/markets.html.

unloading.[36] Further, the storage tanks would have to be heated as bitumen is too viscous to pump at ambient temperatures. The Initial Study identifies only conventional bottom-unload, closed-dome rail cars. ATC, p. 7. The Project description states the "North American crude oil would flow readily at ambient temperatures. Therefore, this Project would not increase the steam demand..." IS, p. 9. However, this does not eliminate pure bitumen as some of the storage tanks in the VIP are heated (VIP DEIR, p. 3-49) and the railcars could be replaced with heated cars in the future unless conditions of certification specifically require unheated cars without insulation and steam coils.

To import undiluted bitumen, the offloading facility would have to be equipped with steam and nitrogen injection systems to heat the rail car coils and remove the crude.[37] The IS/MND and ATC suggest conventional unloading racks. However, Appendix A to the ATC, which contains the drawings and specifications required to affirmatively make this determination, are claimed as confidential business information, preventing full disclosure of the Project description. The details of the loading racks are key to determining the types of crude that can be imported and hence, their impacts. Absent any design information on the loading racks, import of 100% bitumen cannot be eliminated and must be evaluated in an EIR.

In sum, the price discount of tar sands crudes relative to conventional light sweet crudes makes them an attractive crude to import by rail. The Refinery is configured to upgrade these crudes. As discussed in TGG Comments, presentations made by Valero in numerous fora indicate that it is considering importing tar sands crudes, most likely DilBit crudes. Thus, the following sections discuss the impact on emissions of switching from crudes currently imported by ship (Fig. 1) to up to 70,000 BPD of tar sands crudes.[38]

D. Why Does The Specific Crudes Matter?

The air quality impacts of refining North American-sourced crudes such as tar sands crudes depend on the chemical and physical composition of the refinery slate with tar sands crude compared to the current slate.

The chemical composition of tar sands crudes is different in important ways from the current Refinery slate.[39] The current slate includes very little tar sands crudes, from

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[36] Fielden, March 19, 2013.

[37] Fielden, March 19, 2013.

[38] As discussed above, crudes other than Dilbits may be delivered by rail to the Benicia Refinery, especially in the short-term prior to completion of the VIP (Hydrogen Plant) and pending fuller build out of unit train loading facilities in Alberta.

[39] Straatiev and other, 2010, Table 1; Brian Hitchon and R.H. Filby, Geochemical Studies - 1 Trace Elements in Alberta Crude Oils, http://www.ags.gov.ab.ca/publications/OFR/PDF/OFR_1983_02.PDF; F.S. Jacobs and R.H. Filby, Trace Element Composition of Athabasca Tar Sands and Extracted Bitumens, Atomic and Nuclear Methods in Fossil Energy Research, 1982, pp 49-59; James G. Speight, The Desulfurization of Heavy Oils and Residua, Marcel Dekker, Inc., 1981, Tables 1-1, 2-2, 2-3, 2-4 and p. 13 and James G. Speight, Synthetic Fuels Handbook: Properties, Process, and Performance, McGraw-Hill,

0.5% to 2% of the Refinery total crude slate over the period 2010 to 2012 (Fig. 1). The Crude by Rail Project could increase the heavy sour tar sands crude by up to 70,000 BPD, or up to 42% of the permitted Refinery throughput. This represents a significant increase in a crude that will increase emissions compared to the current Refinery slate.

The U.S. Geological Survey ("USGS"), for example, reported that "natural bitumen," the source of all Canadian tar sands-derived oils, contains 102 times more copper, 21 times more vanadium, 11 times more sulfur, six times more nitrogen, 11 times more nickel, and 5 times more lead than conventional heavy crude oil, such as those currently refined from Ecuador, Columbia, and Brazil.[40]

The environmental damage caused by these pollutants includes acid rain; bioaccumulation of toxic chemicals up the food chain; the formation of ground-level ozone and smog; visibility impairment in Class I areas, such as National Parks; odor impacts that affect residents near the Refinery; accidental releases due to corrosion of refinery equipment; and depletion of soil nutrients.

Additionally, many of these chemicals pose a direct health hazard from air emissions. These metals, for example, mostly end up in the coke. Greater amounts of coke are produced by the tar sands crudes than the current crude slate. The California Air Resources Board has classified lead as a pollutant with no safe threshold level of exposure below which there are no adverse health effects. Thus, just the increase in lead from switching up to 42% of the slate to tar sands crude is a significant impact that was not disclosed in the IS/MND. Accordingly, crude quality is critical to a thorough evaluation of the impacts of a crude switch, such as proposed here.

A good crude assay is essential for comprehensive crude oil evaluation.[41] The type of data required to evaluate emissions would require, at a minimum, the following information for both the current slate, the future slate, the displaced crudes, and the unidentified "North American-sourced crudes":

- Trace elements (As, B, Cd, Cl, Co, Cr, Cu, Hg, Mn, Mo, Ni, Pb, Sb, Se, U, V, Zn)
- Nitrogen (total & basic)
- Sulfur (total, mercaptans, H_2S)
- Residue properties (saturates, aromatics, resins)
- Acidity

2008, Tables A.2, A.3, and A.4; Pat Swafford, Evaluating Canadian Crudes in US Gulf Coast Refineries, Crude Oil Quality Association Meeting, February 11, 2010, Available at: http://www.coqa-inc.org/20100211_Swafford_Crude_Evaluations.pdf .

[40] R.F. Meyer, E.D. Attanasi, and P.A. Freeman, Heavy Oil and Natural Bitumen Resources in Geological Basins of the World, U.S. Geological Survey Open-File Report 2007-1084, 2007, p. 14, Table 1, Available at http://pubs.usgs.gov/of/2007/1084/OF2007-1084v1.pdf.

[41] CCQTA February 7, 2012, p. 10.

- Aromatics content
- Asphaltenes (pentane, hexane and heptane insolubles)
- Hydrogen content
- Carbon residue (Ramsbottom, Conradson)
- Distillation yields
- Properties by cut
- Hydrocarbon analysis by gas chromatography

This type of information is reported in a crude assay or "fingerprint" of the oil, which are available to the applicant and was apparently supplied to the BAAQMD as confidential business information, but not the public, foreclosing any meaningful public review. The IS/MND does not identify any specific "North American-sourced crudes" that would be imported, does not contain any crude assays for the current refinery slate, the crude that would be imported by rail, or the crude that is currently imported by ship but would be replaced. The IS/MND also does not contain an analysis of the impact of changes in crude quality on air emissions, arguing instead there would be no change. Thus, the public is left to guess what the impacts might be. The Initial Study should have evaluated the impacts of refining tar sands crudes on air emissions and other residuals or included conditions of certification specifically prohibiting their import as publicly available information indicates that Valero is considering tar sands crudes as they would likely arrive at the Refinery with pricing that is competitive relative to other crudes.

As none of the basic information required to assess air quality impacts is provided in the record, I will discuss in general some of the impacts that can reasonably be expected from including tar sands crudes in the crude slate. Incorporating these "North American-sourced crudes" into the Refinery crude slate could be accomplished, for example, by meeting the API and sulfur range reported in the Initial Study, but with shifts in the means and/or major shifts in other properties, increasing emissions.

The IS/MND is based on the assumption that the composition of the crude slate will not change and thus will not impact air emissions. However, this is based only on two gross or lumper crude quality parameters and ignores the actual chemical composition of the crudes, which is not disclosed in the record.

The specific chemicals, for example, determine which ones will be volatile and lost through equipment leaks and outgassed from tanks, which ones will be difficult to remove in hydrotreaters and other refining processes (thus determining how much hydrogen and energy must be expended to remove them), which ones will cause malodors, and which ones might aggravate corrosion, leading to accidental releases. The Initial Study fails to grasp this distinction and looked only at the range of two gross lumper parameters. Thus, it has failed to satisfy the disclosure requirements of CEQA and failed to analyze relevant impacts.

For example, sulfur is not simply sulfur, but is made up of a complex collection of individual chemical compounds such as hydrogen sulfide, mercaptans, thiophene, benzothiophene, methyl sulfonic acid, dimethyl sulfone, thiacyclohexane, etc. Each crude has a different suite of individual sulfur chemicals. The impacts of "sulfur" depend upon the specific sulfur chemicals and their relative concentrations, not on the range of the "gross" amount of total sulfur expressed as weight percent sulfur, as reported in the Initial Study. The fact that the range in the total sulfur content of rail-imported crude and the current crude slate is the same is irrelevant.

The role of the specific sulfur compounds was clearly and tragically demonstrated in the recent (August 2012) catastrophic accident at the nearby Chevron Richmond Refinery. This accident was caused by the erroneous assumption that sulfur is sulfur, which led to significant corrosion. See discussion elsewhere in these comments. Similarly, while the lighter sulfur compounds such as mercaptans and disulfides found in light sweet crudes may not significantly increase the overall weight percent sulfur in the crude slate, as claimed in the IS/MND, they do lead to impacts, such as aggressive sulfidation corrosion, which can lead to accidental releases. These compounds concentrate in the lower boiling naphtha fraction and contribute to aggressive sulfidation corrosion in the convection section of naphtha hydrotreating furnaces.[42] As another example, the specific sulfur compounds will determine which compounds will be emitted from storage tanks and fugitive component, some of which could result in significant odor impacts, e.g., mercaptans. Thus, regardless of what crude might be brought in by rail, there are potential significant environmental impacts that are due to characteristics of that oil besides total sulfur and API gravity.

There are two significant differences between tar sands crudes that could be imported by rail (but not by ship due to lack of pipelines and ports) and other crudes they may displace: (1) the presence of large amounts of diluent and (2) the chemical composition of the heavy ends or residuum, which must be broken down into lighter products in a refinery.

1. Emissions From Diluent

The majority of the crudes that will be transported by rail will likely be a blend of bitumen and diluent due to their discounted price compared to conventional light sweet crudes. Pure undiluted bitumen is unlikely as the Project description does not disclose any equipment that would be necessary to handle pure bitumen but cannot be excluded as discussed elsewhere. Undiluted bitumen would eliminate the impacts discussed in this section from diluent, but would significantly increase the impacts from refining the heavy ends, namely increased use of utilities that increase combustion emissions. Setting aside undiluted bitumen, this leaves the question of the amount of diluent that would be mixed with the crude, which ultimately determines impacts.

[42] See, for example, Jim McLaughlin, Changing Your Crude Slate, Becht New, May 24, 2013, Available at: http://becht.com/news/becht-news/.

When heavy crude is shipped by pipeline, it needs to be diluted so that it will flow in the pipe. Bitumen blended to pipeline specifications can be loaded on and off conventional rail tank cars like other light crudes. However, bitumen can also be transported by rail as "RailBit," using 15% to 20% diluent. The amount of diluent depends on the type of rail tank car and design details of the offloading facilities. These have been excluded from the IS/MND, which suggests conventional rail cars and a conventional unloading terminal. Further, the number of rail cars, 100 per day, or 700 barrels per car, suggests a lighter material, with more diluent. Thus, I assume that one of the materials that will be transported by rail is conventional pipeline-quality DilBits with 20% to 30% diluent.

However, it is possible that the Project description is inadequate to distinguish between the various possible diluent mixes. There would be, for example, incentive to import RailBit rather than DilBit as it would save on the cost of diluent and transportation. Further, heavy crude refineries such as Valero generally do not want the diluent as it creates a "dumbell" crude curve that contains light components that are not useful to refineries configured to process conventional heavy crudes. Further, transport of undiluted bitumen may be safer as spills do not travel as far from the spill site.

Regardless, the mixture of diluent and bitumen does not behave the same as a conventional crude, as the distribution of hydrocarbons is very different. The blended lighter diluent generally evaporates readily when exposed to ambient conditions, leaving behind the heavy ends, the vacuum gas oil (VGO) and residuum.[43] Thus, when a DilBit is released accidentally, it will generally create a difficult to cleanup spill as the heavier bitumen will be left behind.[44] Further, in a storage tank, the diluent also can be rapidly evaporated and emitted through tank openings.

These conventional DilBits, which are the most likely "North American-sourced crude" to be imported by rail over the long term, given the current economic outlook, are sometimes referred to as "dumbell" or "barbell" crudes as the majority of the diluent is C_5 to C_{12} and the majority of the bitumen is C_{30}+ boiling range material, with very little in between.[45] This means these crudes have a lot of material boiling at each end of the boiling point curve, but little in the middle. Thus, they yield very little middle distillate fuels, such as diesel, heating oil, kerosene, and jet fuel and more coke, than other heavy crudes. A typical DilBit, for example, will have 15% to 20% by weight light material,

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[43] The residuum is the residue obtained from the oil after nondestructive distillation has removed all of the volatile materials. Residua are black, viscous materials. They may be liquid at room temperature (from the atmospheric distillation tower) or almost solid (generally vacuum residua), depending upon the nature of the crude oil.

[44] A Dilbit Primer: How It's Different from Conventional Oil, Inside Climate News. Available at: http://insideclimatenews.org/news/20120626/dilbit-primer-diluted-bitumen-conventional-oil-tar-sands-Alberta-Kalamazoo-Keystone-XL-Enbridge?page=show.

[45] Gary R. Brierley and others, Changing Refinery Configuration for Heavy and Synthetic Crude Processing, 2006, Available at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BA07DE342-E9B1-402A-83F7-36B18DC3DD05%7D&documentTitle=5639138.

basically the added diluent, 10% to 15% middle distillate, and the balance, >75% is heavy residual material (vacuum gas oil and residue) exiting the distillation column. These characteristics distinguish DilBits from crudes currently refined at Benicia.[46]

The large amount of light material that distills below 149 C is very volatile and can be emitted to the atmosphere from storage tanks and equipment leaks of fugitive components (pumps, compressors, valves, fittings) in much larger amounts than other heavy crudes that it would replace. The IS/MND does not indicate whether other heavy crudes processed at the Refinery currently arrive with diluent. However, EIA crude import data, summarized in Figure 1, do not identify any crudes that are blended with diluent. Thus, the use of diluent to transport tar sands crudes is likely an important difference between the current heavy crude slates processed at the Refinery and the tar sands crudes that could replace them. This diluent will have impacts during railcar unloading as well as at many processing units within the Refinery.

The diluent is a low molecular weight organic material with a high vapor pressure that contains high levels of VOCs, sulfur compounds, and HAPs. These would be emitted during unloading and present in emissions from the crude tank(s) and fugitive components from its entry into the Refinery with the crude until it is recovered and marketed, or at least between the desalter and downstream units where some of it is recovered. The presence of diluent would increase the vapor pressure of the crude, substantially increasing VOC and HAP emissions from tanks and fugitive component leaks compared to those from displaced heavy crudes not blended with diluent. The IS/MND and the VIP FEIR did not disclose the potential presence of diluent and made no attempt to estimate these diluent-derived emissions.

The composition of some typical diluents/condensates is reported on the website, www.crudemonitor.ca.[47] The specific diluents that would be used by the Project are unknown. The CrudeMonitor information indicates that diluent contains very high concentrations (based on 5-year averages, v/v basis) of the hazardous air pollutants (HAPs) benzene (7,200 ppm to 9,800 ppm); toluene (10,300 ppm to 25,300 ppm); ethyl benzene (900 ppm to 2,900 ppm); and xylenes (4,600 ppm to 23,900 ppm).

The sum of these four compounds is known as "BTEX" or benzene-toluene-ethylbenzene-xylene. The BTEX in diluent ranges from 27,000 ppm to 60,900 ppm. The BTEX in DilBits, blended from these materials, ranges from 8,000 ppm to 12,300 ppm.[48]

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[46] Stratiev and others, 2010, Table 1, compared to DilBit crude data on www.crudemonitor.ca.

[47] Condensate Blend (CRW) - http://www.crudemonitor.ca/condensate.php?acr=CRW; Fort Saskatchewan Condensate (CFT) - http://www.crudemonitor.ca/condensate.php?acr=CFT; Peace Condensate (CPR) - http://www.crudemonitor.ca/condensate.php?acr=CPR; Pembina Condensate (CPM) - http://www.crudemonitor.ca/condensate.php?acr=CPM; Rangeland Condensate (CRL) - http://www.crudemonitor.ca/condensate.php?acr=CRL; Southern Lights Diluent (SLD) - http://www.crudemonitor.ca/condensate.php?acr=SLD.

[48] DilBits: Access Western Blend (AWB) -http://www.crudemonitor.ca/crude.php?acr=AWB; Borealis Heavy Blend (BHB) -http://www.crudemonitor.ca/crude.php?acr=BHB; Christina Dilbit Blend (CDB) - http://www.crudemonitor.ca/crude.php?acr=CDB; Cold Lake (CL) -

Similarly, the BTEX in synthetic crude oils (SCOs) ranges from 6,100 ppm to 14,100 ppm.[49] These are very high concentrations that were not considered in the emission calculations in the IS/MND and underlying ATC nor in the VIP FEIR. These high levels could result in significant worker and public health impacts.

The ATC estimated emissions of these compounds (ATC, Table 3-3) from Tank 1776 and fugitive components using the "default speciation profile" for crude oil from the EPA program, TANKS4.09d, for all constituents except benzene. For benzene, the IS/MND variously claims it substituted either 0.06wt.% or 0.6wt.% for the default value.[50] Thus, the IS/MND's claims as to benzene in fugitive emissions are internally inconsistent. My research indicates the TANKS default value for benzene in crude oil is 0.6wt.%.[51] The IS/MND lowered this to 0.06wt.% in its HAP emission calculations. IS/MND, Appx. A. The IS/MND contains no support for lowering EPA's crude oil default benzene level by a factor of ten. This value substantially underestimates the amount of benzene that would be present in tank and fugitive component emissions when processing either DilBits or Bakken crudes.

The value of 0.06wt.% benzene used to calculate tank and fugitive benzene emissions contradicts published crude composition for the range of North American-sourced crudes that could be imported by the Project. Table 1 compares the concentration of BTEX used to estimate BTEX emissions in the IS/MND with the BTEX concentrations in various diluents, two widely traded DilBits, including the DilBit that Valero used in its cost analysis (Fig. 2), Western Canadian Select and Bakken crude oils. This table shows that regardless of which material is imported by the Crude by Rail

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http://www.crudemonitor.ca/crude.php?acr=CL; Peace River Heavy (PH) - http://www.crudemonitor.ca/crude.php?acr=PH; Seal Heavy (SH) - http://www.crudemonitor.ca/crude.php?acr=SH; Statoil Cheecham Blend (SCB) - http://www.crudemonitor.ca/crude.php?acr=SCB; Wabasca Heavy (WH) - http://www.crudemonitor.ca/crude.php?acr=WH; Western Canadian Select (WCS) - http://www.crudemonitor.ca/crude.php?acr=WCS; Albian Heavy Synthetic (AHS) (DilSynBit) - http://www.crudemonitor.ca/crude.php?acr=AHS.

[49] SCOs: CNRL Light Sweet Synthetic (CNS) -http://www.crudemonitor.ca/crude.php?acr=CNS; Husky Synthetic Blend (HSB) -http://www.crudemonitor.ca/crude.php?acr=HSB; Long Lake Light Synthetic (PSC) -http://www.crudemonitor.ca/crude.php?acr=PSC; Premium Albian Synthetic (PAS) - http://www.crudemonitor.ca/crude.php?acr=PAS; Shell Synthetic Light (SSX) - http://www.crudemonitor.ca/crude.php?acr=SSX; Suncor Synthetic A (OSA) - http://www.crudemonitor.ca/crude.php?acr=OSA; Syncrude Synthetic (SYN) - http://www.crudemonitor.ca/crude.php?acr=SYN.

[50] The text in the ATC, p. 11, pdf 17, in the note following Table 3-3, states that benzene in crude oil was assumed to be 0.6%. However, in Table 3-5, p. 12, pdf 18, it is stated that benzene in the crude oil was assumed to be 0.06%. Similarly, the supporting appendices indicate that 0.06% benzene was actually used in the fugitive emissions calculations. ATC, Attach. B-3, Fugitive Component Emissions, pdf 33. Similar data for tank emission calculations cannot be checked as it is claimed to be confidential. ATC, Attach. B-2.

[51] Crude oil component speciation data was obtained by using the TANKS409d model available at http://www.epa.gov/ttnchie1/software/tanks/ using the database interface to export the speciation profile for the TANKS default crude oil, *viz.*, "Data --> Speciation Profiles --> Export" menu selection and choosing crude oil. This spreadsheet confirms that the default benzene level for crude oils is 0.6wt.%.

Project, benzene emissions would be much higher than estimated in the IS/MND. Further, benzene emissions are higher in the most recently collected samples than in the five-year averages in Table 1. These benzene emissions would result in significant health impacts.

Table 1
Comparison of BTEX Levels Assumed in IS/MND with Levels in Diluents and DilBits

	Default Crude ATC Attach. B-3 (wt.%)	Diluents (5-yr Avg)[52] (wt.%)	Christina DilBit[53] (5-yr Avg) (wt.%)	Western Canadian Select[54] (5-yr Avg) (wt.%)	Bakken[55] Crude (wt.%)
Benzene	0.06	0.83-1.27	0.27	0.15	0.1-1.0
Ethylbenzene	0.4	0.11-0.33	0.06	0.06	0.33
Toluene	1.00	1.32-2.89	0.44	0.27	0.92
Xylenes	1.4	0.59-2.71	0.34	0.27	1.4

The ATC discloses that annual emissions of benzene from Tank 1776 exceed the BAAQMD chronic trigger level (6.4 lb/yr trigger level compared to a net increase of 28.3 lb/yr). ATC, p. 17-18 & Table 4-3. Further, the IS/MND and underlying ATC fail to disclose that benzene emissions from fugitive components, when calculated using the correct benzene level (> or = 0.6%, rather than 0.06%), also exceed the BAAQMD screening level (6.4 lb/hr screening level compared to 20 lb/hr emitted, adjusted to 0.6% benzene).

The Initial Study conducted a screening health risk assessment. It found no significant health impact. IS, p. II-15. However, the benzene emissions used in this analysis apparently (no support is provided in the record) were underestimated by factors of 2.5 (0.15/0.06 = 2.5) to 4.5 (0.27/0.06 =4.5) assuming DilBits and up to a factor of 17

[52] The reported range includes the following diluents: Condensate Blend, Saskatchewan Condensate, Peace Condensate, Pembina Condensate, Rangeland Condensate, and Southern Lights Diluent. The composition data for all of these diluents is found at http://www.crudemonitor.ca. Concentrations reported in volume % (v/v) in this source were converted to weight % by dividing by the ratio of compound density in kg/m^3 at 25 C (benzene =876.5 kg/m^3, toluene = 0.866.9 kg/m^3, ethylbenzene 866.5 kg/m^3, and the xylenes 863 kg/m^3) to crude oil density in kg/m3, as reported at www.crudemonitor.ca, 5-year average. See also Cenovus Energy Inc. Material Safety Data Sheet, Condensate (Sour) and Condensate (Sweet), Available at: http://www.cenovus.com/contractor/msds.html.

[53] Christina DilBit Blend (CDB) -.http://www.crudemonitor.ca/crude.php?acr=CDB. Concentrations reported in volume % (v/v) converted to weight % as explained in footnote 52.

[54] Western Canadian Select (WCS) -http://www.crudemonitor.ca/crude.php?acr=WCS. Concentrations reported in volume % (v/v) converted to weight % as explained in footnote 52.

[55] Cenovus Energy, Material Safety Data Sheet for Light Crude Oil, Bakken (benzene), Available at: http://www.cenovus.com/contractor/docs/CenovusMSDS_BakkenOil.pdf. Other components of BTEX from Keystone DEIS, Tables 3.13-1 (density) and 3.13-2 (BTEX). Concentrations reported in volume % (v/v) converted to weight % as explained in footnote 52.

(1.0/0.06=17) for Bakken crudes. There is one DilBit with a benzene concentration of 0.06wt.%, Borealis Heavy Blend. However, this represents the lower end of the range for DilBits. There is no evidence that this is the only DilBit that would be imported by rail.

Benzene is a carcinogen, the principal one included in the HAP emission calculations.[56] IS/MND, Appx. A. The only sources of benzene disclosed in the IS/MND is Tank 1776 and fugitives, which were underestimated due to the use of an anomalously low crude concentration. Thus, the cancer risk reported in the IS/MND in Table 3-3 can be adjusted for this error by multiplying the IS/MND Table 3-3 cancer risks by the benzene ratios reported above (benzene in crude of interest from Table 1 ÷ benzene assumed in the IS/MND (0.06wt.%). This assumes the contribution, if any, to cancer risk from ethylbenzene is negligible.

Thus, the reported cancer risk to the maximum exposed worker increases from 4.46 in a million (IS, Table 3-3) up to 11 (4.46x2.5=11.2) to 20 (4.46x4.5= 20.1) in a million for DilBits and up to 76 (4.46x17=76) in a million for Bakken crudes. For the maximum exposed residential receptor, the reported cancer risk increases from 2.27 (IS, Table 3-3) up to 5.7 (2.27x2.5=5.7) to 10 (2.27x4.5=10.2) in a million for DilBits and to 39 (2.27x17=39) in a million for Bakken crudes. These cancer risk levels equal or exceed the assumed cancer significance threshold of 10 in a million. IS, p. II-15. These are significant unmitigated impacts (to workers and nearby residents) that were not disclosed in the IS/MND and are directly caused by the IS/MND's failure to consider the composition of the crude that is being imported.

The CrudeMontior information also indicates that these diluents contain elevated concentrations of volatile mercaptans (9.9 to 103.5 ppm), which are highly odiferous and toxic compounds that will create odor and nuisance problems at the Refinery in the vicinity of the unloading area, crude storage tanks and supporting fugitive components. Mercaptans can be detected at concentrations substantially lower than will be present in emissions from the crude tanks and fugitive emissions from the unloading rack and related components, including pumps, valves, flanges, and connectors.[57] In fact, mercaptans are added to natural gas in very tiny amounts so that the gas can be smelled to facilitate detecting leaks.

Thus, unloading, storing, handling and refining bitumens mixed with diluent and shale crudes such as Bakken would emit VOCs, HAPs, and malodorous sulfur compounds, not found in comparable levels in conventional crudes, depending upon the DilBit or shale crude source. There are no restrictions on the crudes, diluent source or their compositions nor any requirements to monitor emissions from tanks and leaking equipment where DilBit-blended and other light crudes would be handled. As the market

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[56] Ethylbenzene was classified by OEHHA as a weak carcinogen in 2007. See: http://oehha.ca.gov/tcdb/index.asp. As the IS/MND risk calculations were not available, it is uncertain whether the IS/MND's risk assessment included ethylbenzene as a carcinogen.

[57] American Industrial Hygiene Association, Odor Thresholds for Chemicals with Established Occupational Health Standards, 1989; American Petroleum Institute, Manual on Disposal of Refinery Wastes, Volume on Atmospheric Emissions, Chapter 16 - Odors, May 1976, Table 16-1.

has experienced shortages of diluents, any material with a suitable thinning ability could be used, which could contain currently unanticipated hazardous components.

2. Composition of Tar Sands Bitumen

The composition of tar sands crudes is chemically different from other heavy crudes currently processed at the Refinery as they are tar sands bitumen mixed with diluent. They are unique for two major reasons: (1) presence of large quantities of volatile diluent full of VOCs and toxic chemicals and (2) unique chemical composition of the bitumen. The previous comment discussed diluent. This comment discusses the unique composition of tar sands bitumens that require more intense processing and thus higher emissions.

Tar sands bitumens are composed of higher molecular weight chemicals and are deficient in hydrogen compared to conventional heavy crudes. This means more energy will be required to convert them into the same slate of refined products. Thus, most fired sources in the refinery—heaters, boilers, etc.—will have to work harder to generate the same quantity and quality of refined products. This will increase all utilities required to run the refinery - electricity, natural gas, hydrogen, water, and steam. This section discusses these bitumens and their impact on refining emissions.

Refining converts crude oils into transportation fuels. This is done by removing contaminants (sulfur, nitrogen, metals) and breaking down and reassembling chemicals present in the crude oil charge by adding hydrogen, removing carbon as coke, and applying heat, pressure, and steam in the presence of various catalysts. More intensive refining is required to convert tar sands crudes into useful products than other heavy crudes. This means a greater amount of energy must be expended to yield the same product slate. Thus, all of the combustion sources in a refinery, such as heaters and boilers, must work harder and thus emit more pollutants, than when refining conventional heavy and other crudes. The IS/MND fails completely to analyze the impact of crude composition on the resulting emissions from generating increased amount of these utilities.

Canadian tar sands bitumen is distinguished from conventional petroleum by the small concentration of low molecular weight hydrocarbons and the abundance of high molecular weight polymeric material.[58] Crudes derived from Canadian tar sands bitumen—DilBits, SCOs and SynBits—are heavier, i.e., have larger, more complex molecules such as asphaltenes,[59] some with molecular weights above 15,000.[60] They

[58] O.P. Strausz, The Chemistry of the Alberta Oil Sand Bitumen, Available at: http://web.anl.gov/PCS/acsfuel/preprint%20archive/Files/22_3_MONTREAL_06-77_0171.pdf.

[59] Asphaltenes are nonvolatile fractions of petroleum that contain the highest proportions of heteroatoms, i.e., sulfur, nitrogen, oxygen. The asphaltene fraction is that portion of material that is precipitated when a large excess of a low-boiling liquid hydrocarbon such as pentane is added. They are dark brown to black amorphous solids that do not melt prior to decomposition and are soluble in benzene and aromatic naphthas.

generally have higher amounts of coke-forming precursors; larger amounts of contaminants (sulfur, nitrogen nickel, vanadium) that require more intense processing to remove; and are deficient in hydrogen, compared to other heavy crudes.

Thus, to convert them into the same refined products requires more utilities -- electricity, water, heat, and hydrogen. This requires that more fuel be burned in most every fired source at the refinery and that more water be circulated in heat exchangers and cooling towers. Further, this requires more fuel to be burned in any supporting off-site facilities, such as power plants that may supply electricity or Steam-Methane Reforming Plants that may supply hydrogen. Under CEQA, these indirect increases in emissions caused by a project must be included in the impact analysis. These increases in fuel consumption release increased amounts of NO_x, SO_x, VOCs, CO, PM10, PM2.5, and HAPs as well as greenhouse gas emissions (GHG). Some of the principle differences are identified below, followed by a discussion of the impacts these differences have on emissions.

a. Higher Concentrations of Asphaltenes and Resins

The severity (e.g., temperature, amount of catalyst, hydrogen) of hydrotreating depends on the type of compound a contaminant is bound up in. Lower molecular weight compounds are easier to remove. The difficulty of removal increases in this order: paraffins, naphthenes, and aromatics.[61] Most of the contaminants of concern in tar sands crudes are bound up in high molecular weight aromatic compounds such as asphaltenes that are difficult to remove, meaning more heat, hydrogen, and catalyst are required to convert them to lower molecular weight blend stocks. Some tar sands-derived vacuum gas oils (VGOs), for example, contain no paraffins of any kind. All of the molecules are aromatics, naphthenes, or sulfur species that require large amounts of hydrogen to hydrotreat, compared to other heavy crudes.[62]

Asphaltenes and resins generally occur in tar sands bitumens in much higher amounts than in other heavy crudes. They are the nonvolatile fractions of petroleum and contain the highest proportions of sulfur, nitrogen, and oxygen.[63] They have a marked effect on refining and result in the deposition of high amounts of coke during thermal processing in the coker. They also form layers of coke in hydrotreating reactors, requiring increased heat input, leading to localized or even general overheating and thus even more coke deposition. This seriously affects catalyst activity resulting in a marked decrease in the rate of desulfurization. They also require more intense processing in the

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[60] O.P. Strausz, The Chemistry of the Alberta Oil Sand Bitumen, Available at: http://web.anl.gov/PCS/acsfuel/preprint%20archive/Files/22_3_MONTREAL_06-77_0171.pdf.

[61] Gary et al., 2007, p. 200.

[62] See, for example, the discussion of hydrotreating and hydrocracking of Athabasca tar sands cuts in Brierley et al. 2006, pp. 11-17.

[63] James G. Speight, The Desulfurization of Heavy Oils and Residua, Marcel Dekker, Inc., 1981, Tables 1-1, 2-2, 2-3, 2-4 and p. 13 and James G. Speight, Synthetic Fuels Handbook: Properties, Process, and Performance, McGraw-Hill, 2008, Tables A.2, A.3, and A.4.

coker required to break them down into lighter products. These factors require increases in steam and heat input, both of which generate combustion emissions -- NO_x, SO_x, CO, VOCs, PM10, and PM2.5.

Further, if the crude includes a synthetic crude, SCO, for example, the material has been previously hydrotreated. Thus, the remaining contaminants (e.g., sulfur, nitrogen), while present in small amounts, are much more difficult to remove (due to their chemical form, buried in complex aromatics), requiring higher temperatures, more catalyst, and more hydrogen.[64]

The higher amounts of asphaltenes and resins generate more heavy feedstocks that require more severe processing than lighter feedstocks. The coker, for example, makes more coker distillate and gas oil that must be hydrotreated, compared to conventional heavy crudes. Similarly, the Crude Unit makes more atmospheric and vacuum gas oils that must be hydrotreated.[65] This increases emissions from these units, including fugitive VOC emissions from equipment leaks and combustion emissions from burning more fuel.

b. Hydrogen Deficient

Tar sands crudes are hydrogen deficient compared to heavy and conventional crude oils and thus require substantial hydrogen addition during refining, beyond that required to remove contaminants (sulfur, nitrogen, metals). This again means more combustion emissions from burning more fuel.

c. Higher Concentrations of Catalyst Contaminants

Tar sands bitumens contain about 1.5 times more sulfur, nitrogen, oxygen, nickel and vanadium than typical heavy crudes.[66] Thus, much more hydrogen per barrel of feed and higher temperatures would be required to remove the larger amounts of these poisons. These impurities are removed by reacting hydrogen with the crude fractions over a fixed catalyst bed at elevated temperature. The oil feed is mixed with substantial quantities of hydrogen either before or after it is preheated, generally to 500 F to 800 F. The amount of hydrogen required for a particular application depends on the hydrogen content of the feed and products and the amount of the contaminants to be removed. Hydrogen consumption is typically about 70 scf/bbl of feed per percent sulfur, about 320 scf/bbl feed per percent nitrogen, and 180 scf/bbl per percent oxygen removed.[67]

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[64] See, for example, Brierley et al. 2006, p. 8 ("The sulfur and nitrogen species left in the kerosene and diesel cuts are the most refractory, difficult-to-treat species that could not be removed in the upgrader's relatively high-pressure hydrotreaters."); Turini et al. 2011 p. 4.

[65] See, for example, Turini et al. 2011, p. 9.

[66] See, for example, USGS, 2007, Table 1.

[67] James H. Gary, Glenn E. Handwerk, and Mark J. Kaiser, Petroleum Refining: Technology and Economics, 5th Ed., CRC Press, 2007, p. 200 and A.M. Aitani, Processes to Enhance Refinery-Hydrogen Production, Int. J. Hydrogen Energy, v. 21, no. 4, pp. 267-271, 1996.

Canadian tar sands crudes generally have higher nitrogen content, 3,000 to >6,000 ppm[68] and specifically higher organic nitrogen content, particularly in the naphtha range, than other heavy crudes.[69] This nitrogen is mostly bound up in complex aromatic compounds that require a lot of hydrogen to remove. This affects emissions in five ways.

First, additional hydrotreating is required to remove them, which increases hydrogen and energy input. Second, they deactivate the cracking catalysts, which requires more energy and hence more emissions to achieve the same end result. Third, they increase the nitrogen content of the fuel gas fired in combustion sources, which increases NO_x emissions from all fired sources that use refinery fuel gas. Fourth, nitrogen in tar sands crudes is present in higher molecular weight compounds than in other heavy crudes and thus requires more hydrogen and energy to remove. Fifth, some of this nitrogen will be converted to ammonia and other chemically bound nitrogen compounds, such as pyridines and pyrroles. These become part of the fuel gas and could increase NO_x from fired sources. They further may be routed to the flares, where they would increase NO_x.

These types of chemical differences between the current crude slate and the new crude slate facilitated by the Crude by Rail Project were not addressed at all in the IS/MND. While the Refinery may currently be operating with its BAAQMD permits, and the subject increase would not exceed any existing permit limits, the existing permit limits is the wrong baseline for CEQA impact analyses.

However, some of these increased utility impacts were addressed in the VIP FEIR as of 2002. The VIP FEIR admitted that then-proposed changes in the crude slate would cause: (1) an increase in electricity demand of 23 MW; (2) an increase in natural gas consumption of 9.6 MMscf/day (VIP DEIR, pp. 2-3); (3) an increase in the firing rate of heaters and boilers of 400 MMBtu/hr (VIP DEIR, p. 3-47); (4) an increase in the hydrogen capacity of 30 MMscf/day (VIP DEIR, p. 3-39); and an increase in coker capacity of 5,000 BPD (VIP DEIR, p. 3-30). Mitigations were proposed in the VIP FEIR for these significant increases in utility demands. However, this decades old analysis has not been re-evaluated to determine if the current proposed change in crude slate would result in increased impacts within the framework of the VIP or if the changed regulatory framework requires more aggressive mitigation.

E. Does the VIP FEIR Mitigate The Impacts Of Refining Tar Sands Crudes?

The Valero Improvement Project is designed to process increased amounts of heavy sour crudes such as Canadian tar sands crudes. It identified some of the impacts of this proposed switch in crudes, including an increase in the amount of electricity that

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[68] Murray R. Gray, Tutorial on Upgrading of Oil Sands Bitumen, University of Alberta, Available at: http://www.ualberta.ca/~gray/Links%20&%20Docs/Web%20Upgrading%20Tutorial.pdf.

[69] See, for example, James G. Speight, Synthetic Fuels Handbook: Properties, Process, and Performance, McGraw-Hill, 2008, Appendix A.

would be used (23 MW), an increase in the amount of natural gas that would be burned, and an increase in the amount of hydrogen that would be required. All of these increases in utilities also increase emissions and were mitigated to various degrees in the VIP FEIR as of a 1999 to 2001 baseline. However, this is not the correct baseline to evaluate the Crude by Rail Project. These increases in utilities, concomitant emission increases, and proposed VIP mitigations must be evaluated relative to the physical baseline at the time of the Crude by Rail Project environmental review, or 2009 to 2011.

1. The Impacts from VIP and Crude by Rail Project Must Be Considered Together

The VIP environmental analysis was performed over 10 years ago. Much has changed in the last 10 years, from the suite of tar sands products available in the market, to the transportation options (ship was considered feasible 10 years ago, today, rail is required), to the timing of implementation of the VIP, to the regulatory framework. Thus, a new, full, thorough analysis is required in conjunction to the proposed Crude by Rail Project. The impacts of importing unidentified crudes by rail cannot be reasonably evaluated without keying off of this prior analysis. Some examples follow.

The VIP FEIR, for example, assumes that the use of a higher percentage of sour crudes would mitigate increases in VOC emissions from increasing crude throughput. VIP RTC, p. IV-61. The reported increase in fugitive VOC emissions over the 3-year baseline 1999-2001 was only 3 ton/yr, which at the time was less than the CEQA significance threshold. VIP DEIR, Table 4.2; VIP Addendum, Table 2. However, this assumed heavier crudes would be refined under the VIP than were refined in the 1999-2001 baseline, which offset most of the increase in fugitive VOC emissions from a 25% increase in crude throughput under the VIP. These VOC emissions include large amounts of hazardous air pollutants, such as benzene, toluene and xylenes, that result in significant health impacts, including cancer.

However, the proposed Crude by Rail project asserts that the imported crudes could include up to 70,000 BPD of light, low density crudes. These crudes have a much higher vapor pressure than the crude slate contemplated in the VIP FEIR and would significantly increase VOC emissions from tanks, pumps, compressors, valves, and connectors throughout the Refinery compared to the scenario analyzed in the VIP FEIR. Further, the FEIR explicitly assumes that the imported heavy sour crudes would mitigate increases in VOC emissions. This assumption did not consider the fact that diluents are now widely used to blend with the crudes. Or that light shale crudes may be imported, which would not offset VOC increases. These diluents or shale crudes consist of light hydrocarbons, including large amounts of benzene, toluene and xylene, which would increase VOC emissions from tanks, pumps, compressors, valves, and connectors throughout the Refinery.

The BAAQMD CEQA significance threshold for VOCs is 15 ton/yr. Assuming 70,000 BPD of the crude throughput or 42% of the total, is light sweet crude, as now asserted in the Crude by Rail project, the VOC emissions would increase to more than 104 ton/yr (73x1.42=104) or by 31 ton/yr (104-73=31). This exceeds the BAAQMD

CEQA significance threshold by a factor of two and is a very significant unmitigated impact, triggering an EIR.

Actual increases could be much higher under any of the currently understood plausible scenarios, importing light sweet crude under the Crude by Rail Project, or importing diluent-blended DilBit under the VIP project. These increases in VOCs from importing a light sweet crude or a diluent blended tar sands crude would greatly exceed the 15 ton/yr VOC threshold as demonstrated above. Alternatively, assuming just the 25% increase in throughput under the VIP, based on light sweet crudes, the fugitive VOC emissions would increase from 73 ton/yr in the 1999 to 2001 baseline to 91.25 ton/yr (73x1.25 = 91.25), or by 18.25 ton/yr (91.25-73=18.25). Thus, fugitive VOC emissions are a significant undisclosed impact of the Crude by Rail Project, requiring an EIR. These increases were not considered in either the VIP FEIR or the IS/MND and are a significant unmitigated impact of the Project.

2. The Impacts from the VIP Project and the Crude By Rail Project Are Cumulatively Considerable

The VIP Project is still being constructed. The last portion of this project, the new Hydrogen Plant, will be under construction at the same time that the new rail terminal is being constructed. The Initial Study estimated that the daily average construction exhaust emissions from building the rail terminal would be 51.9 lb/day. IS, Table 3-1. The CEQA significance threshold is 54 lb/day.[70] The VIP FEIR did not calculate construction emissions, as this was not required at the time, an example of the change in regulatory framework. However, based on my experience calculating construction emissions for many projects, the NOx emissions from constructing the Hydrogen Plant would exceed 2.1 lb/day and thus NOx emissions from simultaneously constructing the Hydrogen Plant and the Crude by Rail project would be cumulatively significant.

3. The Regulatory Framework Has Changed

Ten years have passed since the environmental analysis was done for the VIP and the FEIR was certified. As the VIP FEIR was certified in 2003, and amended in 2007, the regulatory and informational framework within which the Project would be developed today has changed dramatically, rendering the 2002 analysis obsolete.

Since the VIP FEIR was certified in 2003, new scientific evidence about the potential adverse impacts of air pollutants has become available, and in response, new guidance has been published and several federal and state ambient air quality standards have been revised. These include:

[70] Staff-Recommended CEQA Threshold of Significance, Available at: http://www.baaqmd.gov/~/media/Files/Planning%20and%20Research/CEQA/Staff-Recommended%20and%20Existing%20CEQA%20Thresholds%20Table%2010-07-09.ashx?la=en.

- The 8-hour CA ozone standard was approved by the Air Resources Board on April 28, 2005 and became effective on May 17, 2006.
- The EPA lowered the 24-hour PM2.5 standard from 65 $\mu g/m^3$ to 35 $\mu g/m^3$ in 2006. EPA designated the Bay Area as nonattainment of the PM2.5 standard on October 8, 2009.
- On June 2, 2010, the U.S. EPA established a new 1-hour SO_2 standard, effective August 23, 2010.
- The EPA promulgated a new 1-hour NO_2 standard of 0.1 ppm, effective January 22, 2010.
- The EPA issued the greenhouse gas tailoring rule in May 2010, which requires controls of GHG emissions not contemplated in the VIP FEIR.
- The California Air Resources Board has identified lead and vinyl chloride as 'toxic air contaminants' with no threshold level of exposure below which there are no adverse health effects determined.
- The EPA issued a final rule for a national lead standard, rolling 3-month average, on October 15, 2008.

Emissions must be reduced to assure that these new regulatory levels are not exceeded. Lead, for example, can be present in very high concentrations in fugitive dusts from coke storage, handling, and export, especially when heavy sour crudes are being processed. There is a long history of nuisance coke dust issues at this Refinery that impact residents. See, e.g., VIP DEIR, p. 4.2-14. The VIP would increase coke production and thus fugitive coke dust emissions with elevated lead levels. The proposed Crude by Rail Project also could increase coke production, depending upon the specific "North American-sourced crude" that it imports.[71] This possibility cannot be eliminated based on the record. The California Air Resources Board has concluded there is no safe threshold level of exposure for lead. Any amount poses significant health risks. Thus, the increase in coke fugitive emissions admitted in the VIP EIR and facilitated by the Crude by Rail Project are a significant public health impact under today's regulatory framework.

The VIP DEIR assumed health impacts from coke dust exposure would be mitigated by complying with the then-current PM10 and PM2.5 regulations. VIP DEIR, p. 4.8-14. However, these have been significantly lowered and an ambient air quality standard for lead has been promulgated. There has been no demonstration that the increase in lead-laden coke dust, that could reasonably be expect to result from the Crude to Rail Project, could comply with these new standards or that such compliance would mitigate lead health impacts, given the CARB's zero threshold finding.

[71] The VIP DEIR did not disclose the actual coke increase, but did acknowledge that it would increase coke exports over the dock by 12 ships per year and by rail of 5 rail cars per day. VIP DEIR, p. 3-52. The capacity of a coke ship and coke rail cars was not disclosed.

Similarly, very high concentrations of NO_2 are present in the exhaust emissions from diesel train engines that would be used at the newly proposed rail terminal. Based on my work at other rail loading terminals, these NO_2 emissions are routinely high enough to exceed the new 1-hour NO_2 standard. While annual NO_2 emissions may be offset of reducing ship imports, the ambient impacts would occur at different locations and times, exceeding the new 1-hour NO_2 standard. This was not considered in the IS/MND and is a significant impact that requires that an EIR be prepared. These emissions can and must be mitigated, for example by using an electronic positioning system,[72] rather than the locomotive engine, to move the cars through the unloading facility.

III. ACCIDENTAL RELEASES WILL INCREASE

The Benicia Refinery was built before current American Petroleum Institute (API) standards were developed to control corrosion and before piping manufacturers began producing carbon steel in compliance with current metallurgical codes. While some of Benicia's metallurgy was updated as part of the VIP, metallurgy used throughout much of the Refinery is likely not adequate to handle the unique chemical composition of tar sands crudes without significant upgrades. There is no assurance that required metallurgical upgrades would occur as they are very expensive and not required by any regulatory framework. Experience with changes in crude slate at the nearby Chevron Refinery in Richmond suggest required metallurgical upgrades are ignored, leading to catastrophic accidents.[73] The IS/MND is silent on corrosion issues and metallurgical conditions of the Refinery.

Both DilBit and SynBit crudes have high Total Acid Numbers (TAN), which indicates high organic acid content, typically naphthenic acids. These acids are known to cause corrosion at high temperatures, such as occur in many refining units, e.g., in the feed to cokers. As a rule-of-thumb, crude oils with a TAN number greater than 0.5 mgKOH/g[74] are considered to be potentially corrosive and indicates a level of concern. A TAN number greater than 1.0 mgKOH/g is considered to be very high. Canadian tar sands crudes are high TAN crudes. The DilBits, for example, range from 0.98 to 2.42 mgKOH/g.[75]

Sulfidation corrosion from elevated concentrations of sulfur compounds in some of the heavier distillation cuts is also a major concern, especially in the vacuum

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[72] See, for example, Oregon Department of Environmental Quality, Standard Air Contaminant Discharge Permit, Coyote Island Terminal, LLC, July 24, 20120, p. 3, Condition 1.1.a (an electric powered positioning system for maneuvering railcars through the Railcar Unloading Building).

[73] U.S. Chemical Safety and Hazard Investigation Board, Interim Investigation Report, Chevron Richmond Refinery Fire, Chevron Richmond Refinery, Richmond, California, August 6, 2012, Draft for Public Release, April 15, 2013, Available at; http://www.csb.gov/chevron-refinery-fire/.

[74] The Total Acid Number measures the composition of acids in a crude. The TAN value is measured as the number of milligrams (mg) of potassium hydroxide (KOH) needed to neutralize the acids in one gram of oil.

[75] www.crudemonitor.ca.

distillation column, coker, and hydrotreater units. The specific suite of sulfur compounds may lead to increased corrosion. The IS/MND did not disclose either the specific suite of sulfur compounds or the TAN for the proposed crude imports.

A crude slate change could result in corrosion from, for example, the particular suite of sulfur compounds or naphthenic acid content, that leads to significant accidental releases, even if the crude slate is within the current design slate basis, due to compositional differences.

This recently occurred at the nearby Chevron Richmond Refinery. This refinery gradually changed crude slates, while staying within its established crude unit design basis for total weight percent sulfur of the blended feed to the crude unit. This is the scenario the IS/MND and VIP FEIR assume will mitigate all crude slate issues. However, the sulfur composition at Chevron Richmond significantly changed over time.[76] This change increased corrosion rates in the 4-sidecut line, which led to a catastrophic pipe failure in the #4 Crude Unit on August 6, 2012. This release sent 15,000 people from the surrounding area for medical treatment due to the release and created huge black clouds of pollution billowing across the Bay.

These types of accidents can be reasonably expected to result from incorporating tar sands crudes into the Benicia slate, even if the range of sulfur and gravity of the crudes remains the same, unless significant upgrades in metallurgy occur, as these crudes have a significant concentration of sulfur in the heavy components of the crude coupled with high TAN and high solids, which aggravate corrosion. The gas oil and vacuum resid piping, for example, may not be able to withstand naphthenic acid or sulfidation corrosion from tar sands crudes, leading to catastrophic releases.[77] Catastrophic releases of air pollution from these types of accidents were not considered in the IS/MND.

Refinery emissions released in upsets and malfunctions can, in some cases, be greater than total operational emissions recorded in formal inventories. For example, a recent investigation of 18 Texas oil refineries between 2003 and 2008 found that "upset events" were frequent, with some single upset events producing more toxic air pollution than what was reported to the federal Toxics Release Inventory database for the entire year.[78]

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[76] US Chemical Safety and Hazard Investigation Board, 2013, p.34 ("While Chevron stayed under its established crude unit design basis for total wt. % sulfur of the blended feed to the crude unit, the sulfur composition significantly increased over time. This increase in sulfur composition likely increased corrosion rates in the 4-sidecut line.").

[77] See, for example, Turini and others, 2011.

[78] J. Ozymy and M.L. Jarrell, Upset over Air Pollution: Analyzing Upset Event Emissions at Petroleum Refineries, Review of Policy Research, v. 28, no. 4, 2011.