Exhibit H

Expert Report of Greg Karras

Communities for a Better Environment (CBE)
4 September 2013

Regarding the

Phillips 66 Company Propane Recovery Project
Draft Environmental Impact Report released in June 2013 by the
Contra Costa County Department of Conservation and Development
State Clearinghouse #2012072046
County File #LP12-2073

Contents

I, Greg Karras, declare and say:

1. I reside in unincorporated Marin County and am employed as a Senior Scientist for Communities for a Better Environment (CBE). My duties for CBE include technical research, analysis, and review of information regarding industrial health and safety investigation, pollution prevention engineering, pollutant releases into the environment, and potential effects of environmental pollutant accumulation and exposure.

Qualifications

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

3. Among other assignments, I served as an expert for CBE and other non-profit groups in efforts to prevent pollution from refineries, to assess environmental health and safety impacts at refineries, to investigate alternatives to fossil fuel energy, and to improve environmental monitoring of dioxins and mercury. I served as an expert for CBE in collaboration with the City and County of San Francisco and local groups in efforts to replace electric power plant technology with reliable, least-impact alternatives.

I served as an expert for CBE and other groups participating in environmental impact reviews of related refinery projects, including, among others, the Chevron Richmond refinery "Hydrogen Renewal Project" now subject to reanalysis pursuant to a California Court of Appeals Order,[1] and the "Contra Costa Pipeline Project" now pending before the County.[2] I serve as an expert for CBE in collaboration with labor, academic, and other community based and environmental groups in a project involving comprehensive investigation of environmental health and safety impacts of, and alternatives to, refining denser, more contaminated types of crude oils.

4. I authored a technical paper on the first publicly verified pollution prevention audit of a California petroleum refinery in 1989 and the first comprehensive analysis of refinery selenium discharge trends in 1994. I authored an alternative energy blueprint, published in 2001, that served as a basis for the Electricity Resource Plan adopted by the City and County of San Francisco in 2002. From 1992–1994 I authored a series of technical analyses and reports that supported the successful achievement of cost-effective pollution prevention measures at 110 industrial facilities in Santa Clara County. I authored the first comprehensive, peer-reviewed dioxin pollution prevention inventory for the San Francisco Bay, which was published by the American Chemical Society and Oxford University Press in 2001. In 2005 and 2007 I co-authored two technical reports that documented air quality impacts from flaring by San Francisco Bay Area refineries, and identified feasible measures to prevent these impacts.

5. My recent publications include the first peer reviewed estimate of combustion emissions from refining denser, more contaminated "lower quality" crude oils based on data from U.S. refineries in actual operation, which was published by the American Chemical Society in the journal *Environmental Science & Technology* in 2010, and a follow up study that extended this work with a focus on California and Bay Area refineries, which was peer reviewed and published by the Union of Concerned Scientists in 2011. Most recently, I presented invited testimony on *inherently safer systems* requirements for existing refineries that change crude feedstock at the U.S. Chemical Safety Board's public hearing on the Chevron Richmond refinery fire that was held on 19 April 2012. My curriculum vitae and list of publications are attached hereto.

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[1] <u>See</u> *CBE v. City of Richmond* 184 Cal_App.4th.

[2] <u>See</u> Contra Costa Pipeline Project file, County File #LP072009, SCH #2007062007.

Scope of Review

6. In my role at CBE I have reviewed the proposed project called the Phillips 66 Company Propane Recovery Project (project) and the June 2013 Draft Environmental Impact Report (DEIR) released by Contra Costa County for public review of the proposed project. My review of the project and DEIR reported herein is focused on catastrophic incident, flaring, air emission, cooling system, and climate impacts that could result from the project. My opinions on these matters and the basis for these opinions are stated in this report.

Project Description

7. According to the DEIR, the project would install, at the Phillips 66 San Francisco Refinery (SFR) Rodeo facility, process equipment that would enable the refinery to treat, recover, store, and ship for sale 8,000 barrels[3] of additional liquefied petroleum gases (LPG) daily, including 4,200 b/d of propane and 3,800 b/d of additional[4] butane. This equipment would include:

- a three-reactor hydrotreater installed to the coker and related fuel gas treatment;
- three 120–140 foot tall fractionator towers and two 70 foot tall absorber towers;
- 140 MMBtu[5] per hour of expanded steam boiler capacity to heat this processing;
- six pressurized propane storage tanks totaling 15,000 barrels capacity; and
- two additional rail spurs and a two-sided loading rack to load eight rail cars/day.[6]

8. Ancillary equipment such as additional process vessels, heat exchangers, pumps, and piping would be installed, and modifications to an existing once-through system would increase Bay water use to 40,000 gallons/minute to cool the new processing.[6]

9. Information that is needed to understand and evaluate the environmental implications of this project has, in many cases, been omitted from the DEIR, even though the same information that the DEIR omits is publicly available from other sources. Some forty of these critically important deficiencies in the DEIR's description of the project are discussed in paragraphs 10 through 47.

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[3] 1 barrel (b): 42 gallons; 0.159 cubic meter (m^3). Conversely, 1 m^3: 6.29 barrels; 264 gallons.
[4] The refinery already produces 5,500 b/d of butane for sale, based on the DEIR at 3-21.
[5] MMBtu: 1 million Btu (British thermal units); 1.00551 gigajoule (GJ).
[6] <u>See</u> DEIR at 3-21, Table 3-2, 3-27.

10. The DEIR does not disclose how long the project could be expected to operate. The omission is important because the time frame of the project must be identified to understand and evaluate potential impacts of project operation over that time.

11. There is no good reason why the time over which the project may reasonably be expected to operate should be kept secret in the DEIR. An operating life estimate must have been made to support critical equipment design specifications, such as vessel wall thickness and materials of construction to resist corrosion, and schedules for major maintenance "turnarounds." Phillips 66 also would have used this estimate in financial analysis before committing to the project. Publicly reported data show similar refinery processes have operated for 30–50 years or more.[7] Another EIR for a proposed project at the Richmond refinery suggested it is "reasonable to use past history as a guideline" and to expect similar "equipment to be operated for several decades."[8] Moreover, an EIR for a related project at this refinery disclosed and analyzed a 40 year project duration.[9]

12. Impacts of the project that would emerge later and are obscured by this omission include those from its effects on a concurrent feedstock switch. California refiners' long-stable and dominant sources of crude oil are dwindling, driving an historic refinery crude switch. See Chart 1. Foreign crude was only 6% of total California refinery crude feed in 1990; in 2012 it was 51%.[10] By 2020, roughly three-quarters of the crude refined statewide likely will *not* be from currently producing sources in California or Alaska.[11] Because it relies on dwindling California oil supplies via pipeline for most of its crude feed,[12] the SFR almost certainly will be among those California refineries that switch crudes dramatically during the project's operating life. Indeed, the refinery's 1995 wharf project forecast this outcome,[9] and its recent related project to allow 67% more crude delivered via its wharf[13] would begin to implement the switch. Among other problems, omitting the operating life of the project obscures the project's implications for the choice of new crudes, and the impacts of that feedstock choice.

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[7] See BAAQMD, 2009; and BAAQMD, 2011.

[8] See City of Richmond, 2008. SCH #2005072117, FEIR Response to Comments, page 3.16a-1.

[9] FEIR SCH #91053082 (State Lands, 1995). See section 4 at pages S-1 (stating a 40-year project duration) and S-4 ("it is assumed that sources of San Joaquin" and "Alaskan crude, will decline" and "[m]ore reliance will be placed on crude imports from foreign sources").

[10] Cal. Energy Commission (http://energyalmanac.ca.gov/petroleum/statistics/crude_oil_receipts).

[11] See Baker & O'Brien, 2007; and Croft, 2009.

[12] Based on *Oil & Gas Journal* capacity and 11.2–18.7 MMb/y wharf limit.

[13] Based on 11.2 vs 18.7 MMb/yr (DEIR at 5-4); see also ERM & BAAQMD, 2012.

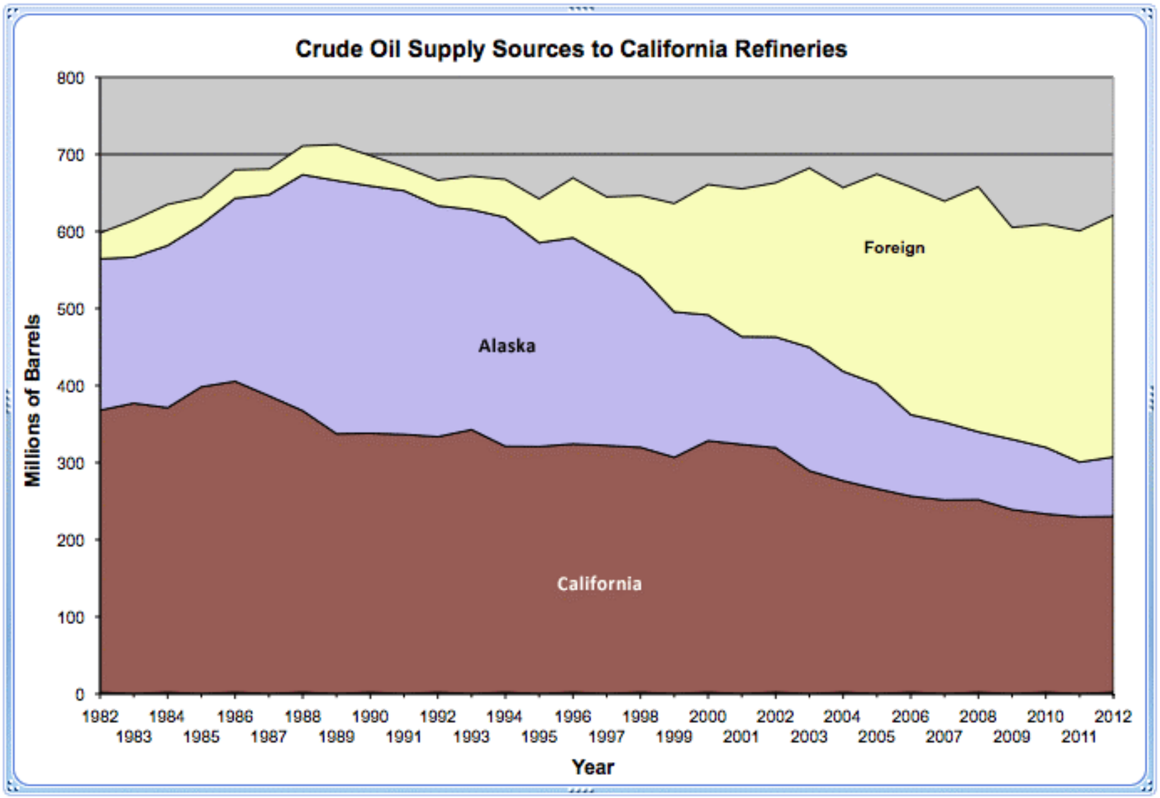

Chart 1. Crude oil supply sources to California refineries, 1982–2012
California Energy Commission (http://energyalmanac.ca.gov/petroleum/statistics/crude_oil_receipts).

13. The DEIR does not report the crude oil quantity processed by the refinery. Its crude throughput (≈120,000 b/d[14]) must be known to understand and evaluate the scale of environmental impacts resulting from project effects on crude processing.

14. The DEIR does not disclose the changes in crude oil use that could result from the project. Data summarized in Table 1 suggests that meeting project objectives would increase the refinery's total LPG production for export sales to 11.2% of its total crude feed volume, 230–570% of the butane yield from initial distillation of its total crude feed, and 450–1,200% of the propane yield from distilling that crude.[15] This change in

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[14] San Francisco Refinery (SFR) crude capacity in b/cd; volume that can be processed during 24 hours after making allowances for types and grades of inputs and products, environmental constraints and scheduled downtime (*Oil & Gas Journal*, 2012). This value is close to those the company reported to air and water officials (see Phillips, 2012b; SFR NPDES permit orders).

[15] See data in Table 1. LPG production from DEIR at 3-21. Total post-project butane export is included because project equipment would replace existing processing for production of butane that is now exported and would not change existing crude distillation equipment to change LPG yield from crude distillation. See also EIA Refinery Yield: Monthly average U.S. refinery LPG yield ranged from 1.8–5.7% on crude volume during January 1993–May 2013.

processing would affect refinery production and create environmental impacts in several ways the DEIR does not describe:

- The location of emissions from LPG combustion would change. LPG now used as refinery fuel that is self-produced from crude would be removed from refinery fuel gas and sold for uses involving combustion at a different location.
- Fuel gas heat content would decline, as more LPG is removed from fuel gas and replaced with natural gas, which has a lower heat content. This could affect combustion sources, fuel gas balance, and flare gas recovery refinery wide. Effects from this fuel gas quality problem are different from, and could occur regardless of, the fuel gas quality improvement from sulfur removal that the DEIR describes.
- The refinery would become more reliant on severe processing of the denser oils in the crude stream in order to create enough byproduct gases from "cracking" these oils to fill the LPG gap between its crude distillation yield and LPG production objectives. This would be necessary to meet project export objectives because the refinery could not otherwise create enough propane and butane, and further would be driven by the enlarged revenue and profit streams from meeting those objectives.

Table 1. Post-project LPG production greatly exceeds refinery crude distillation yield

	Initial crude distillation yield[a]		Post-project LPG production[b]	
	% vol. on crude	barrels/day[c]	barrels/day	% of crude feed[c]
Propane	0.30–0.78	360–936	4,200	3.50
Butanes	1.35–3.31	1,620–3,970	9,300	7.75

(a) Median and 95th Percentile yields from 205 publicly reported crude oil assays (see Crude Assays).
(b) Total post-project production for export sales based on capacity reported (DEIR at 3-21).
(c) Calculated based on reported crude capacity of 120,000 b/cd from *Oil & Gas Journal* (2012).

15. The DEIR does not disclose the change in crude feed quality that could result from the project. The configuration of this project and refinery requires coking for the additional LPG-rich byproduct gases to meet the project's production and profit goals. Installing a catalytic cracker[16] or repurposing a hydrocracker would entail capital or lost motor vehicle fuels production costs that make those options conflict with maximizing LPG export profits. The U200 delayed coker is the primary source of LPG-rich gases that cannot be treated adequately by DGA (amine) processing; the project would "[i]nstall to U200" hydrotreating to provide this treatment; and the new hydrotreater's proposed purpose in this project is to allow LPG to be recovered from coker gases.[17]

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[16] The Phillips 66 SFR does not include a catalytic cracking process. See BAAQMD, 2013.
[17] Phillips, 2012b at 4; DEIR at 3-5, 3-12, 3-16, 3-21, 3-23/24/25, 6-4/5; Phillips, 2012a at 5.

Delayed coking is severe thermal cracking (415–515 ºC at 15–90 psi for ≈24 hours) that is used to crack the densest oil streams processed, such as the residue from vacuum distillation of atmospheric distillation bottoms and bitumen.[18] Thus, the project would commit the refinery to continued coking of the highest-density part of the crude resource.

16. Importantly, denser coker feeds produce more gases and more LPG. Coking converts dense components of crude into oil streams that can be processed further to make light liquid fuels.[18] Named for its petroleum coke byproduct, it also creates byproduct gases with 1–4 carbon atoms (C4–), including butanes (C4) and propane (C3), which are burned as refinery fuel or, especially in the case of C3 and C4, sold as LPG.[19] Along with temperature, pressure, and reaction time, key process variables include feedstock properties and product targets.[20] Data summarized in Table 2 suggest that even at full coker capacity,[21] producing 8,000 b/d of LPG from refinery coker gases could require running the densest vacuum residues. Though it shows estimates only for a few possible feeds, Table 2 illustrates how, by adding an LPG export objective to its coker output, the project will drive the refinery to coking higher density feeds.

Table 2. Denser feeds increase C4– (including LPG) yield from delayed coking

Vacuum resid feed			
cut point (ºC)	+482	+538	+538
density (kg/m^3)	952–981	1,013	1,044
sulfur content (% wt.)	0.50–0.60	3.40	5.30
C4– (including LPG) yield			
C4– yield (% vol.)	10–11	15	17
C4– yield at 47 kbpd coker capacity **(b/d)**	4,700–5,310	6,880	7,930

C4–: hydrocarbons with 4 carbons or less; LPG (butanes and propane) and lighter gases.
Data from tables 7.1-2 and 7.1-6 in Meyers, 1986. C4– overestimates LPG yield. Yield converted from mass to volume assuming all C4– is LPG with 539 kg/m^3 density, and 967 kg/m^3 density coke.

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[18] See Meyers, 1986; Speight, 1991. Heavy or aliphatics-rich synthetic crude oils (SCOs) derived from partially pre-processing tar sands bitumen or crude residua may be included in these coker feeds, and refiners have sometimes labeled such SCOs as "gas oils," but calling them gas oil in this context is misleading. The DEIR does not disclose the project's reliance on low-quality oils.
[19] Delayed coking byproducts also include mercaptans and olefins (Meyers, 1986), which the new hydrotreater would remove from coker gases (Phillips, 2012a). Mercaptans are highly odorous: the coker thus may be linked to the refinery's notorious odor problems. These coking byproduct contaminants appear to be the reason for the new hydtrotreater but are not named in the DEIR.
[20] See Meyers (1986) at 7-69. The DEIR does not disclose this project link to coker operation.
[21] 47,000 b/cd (*Oil & Gas Journal,* 2012).

17. Thus, the project's new commitment to coking denser oils in order to meet its LPG export sales objective would lock the refinery into a crude slate at least as dense as, and likely denser than, its current slate. It likely would be denser because making more LPG would drive the refinery toward coking higher-density vacuum resid and bitumen and also toward increasing coker feed rates.[22] This would make denser vacuum resids, bitumen, or both a larger share of the crude slate, driving the density of the crude slate up.[23] Worse, it would do so during a period when the refinery almost certainly must switch—and in fact is beginning to switch—to new sources for its crude supply, as discussed in paragraphs 11 and 12. The project would thereby lock the refinery into a new crude slate of lower quality than it need otherwise choose. The DEIR does not disclose this effect of the project.

18. Contamination of refinery feedstock would increase as a result of the project. Sulfur and other toxic trace elements concentrate in the densest components[24] of crude that the imperative to produce more coker LPG would make a larger portion of the refinery's crude slate. Imports likely to dominate the new slate in order to fill SFR coking capacity—39% of its total feed volume[25]—with vacuum resid feeds as dense as the high-LPG feed shown in Table 2 could boost sulfur content substantially. See Table 3. Regional trends also support this expectation. See Chart 2. Indeed, sulfur in the new slate could reach ≈3–4.5% wt. The DEIR omits crude quality data,[22] but the crude feed is not nearly that high in sulfur now.[26] Available information suggests that the current average Rodeo feedstock is ≈915–918 kg/m^3 in density and ≈1–1.5 wt. % sulfur.[27] The crude slate resulting from the project likely would be denser and far more contaminated.

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[22] A separate environmental review of increased throughput rates reports some of the crude feed data that the DEIR should and could have reported, and reveals the company's plans to increase throughput rates for at least some of its upstream processing (see SMF EIR 2012 Excerpts). The DEIR does not mention or disclose this other proposed project or environmental review.

[23] The density of a crude oil is proportional to the volume of higher molecular weight, higher boiling point, larger hydrocarbons in that crude oil. See Karras, 2010; Speight, 1991.

[24] Sulfur, as well as nickel and vanadium, among other toxic elements, concentrates in the vacuum residua component of crude and bitumen. See Speight, 1991; Karras, 2010.

[25] SFR's 47,000 b/d of coking is 39% of its 120,000 b/d crude capacity (*Oil & Gas J.* data).

[26] Compare UCS (2011), ERM & BAAQMD (2012), *Oil & Gas Journal,* SMF EIR (2012) and EIA Imports Analysis: the Alaskan, imported, and San Joaquin (weighted average pipeline component) streams that comprise about three-quarters of Rodeo's slate have a combined average sulfur content of ≈1 wt. %: an average of 3% sulfur in this *current* slate is not plausible.

[27] UCS, 2011; ERM & BAAQMD, 2012; SMF EIR 2012.

Table 3. Selected data for crude oils with dense (≥ 1,040 kg/m^3) vacuum residue yield comprising ≈30–39% of the whole crude oil's total volume.

	DOE avg.[a] for these crude oils	Eocene[b] Crude (Mid-East)	Crude oils containing bitumen from tar sands[c]			
			Access Western	Christina Dilbit Bld.	Surmont Heavy Bld	WCS*
Whole crude						
density (kg/m^3)	918	945	922	923	936	929
sulfur (wt. %)	2.98	4.57	3.94	3.80	2.99	3.51
TAN (mg KOH/g)	——	0.20	1.70	1.55	1.39	0.94
nickel (ppm wt.)	——	21	72	68	51	58
vanadium (ppm)	——	59	194	179	140	141
Vacuum residue						
volume (% crude)	34	34	36	36	29	37
density (kg/m^3)	1,060	1,070	1,062	1,059	1,061	1,054
sulfur (wt. %)	6.04	7.35	6.49	6.21	6.07	5.56
Vacuum Gas Oil & Residue combined						
volume (% crude)	53	68	61	60	56	63

*WCS: Western Canadian Select. (a) Data from the U.S. Dept. of Energy, Crude Oil Analysis Database: shown is the average of all data for crude oils with residue yields that are 30–39% of crude volume, and also denser than 1,040 kg/m^3 (n = 15). (b) Data from publicly reported assays of traded oils (Chevron, 2013). (c) Data from Canadian Crude Quality Monitoring Program. See Crude Assays; DOE COA 2013, attached).

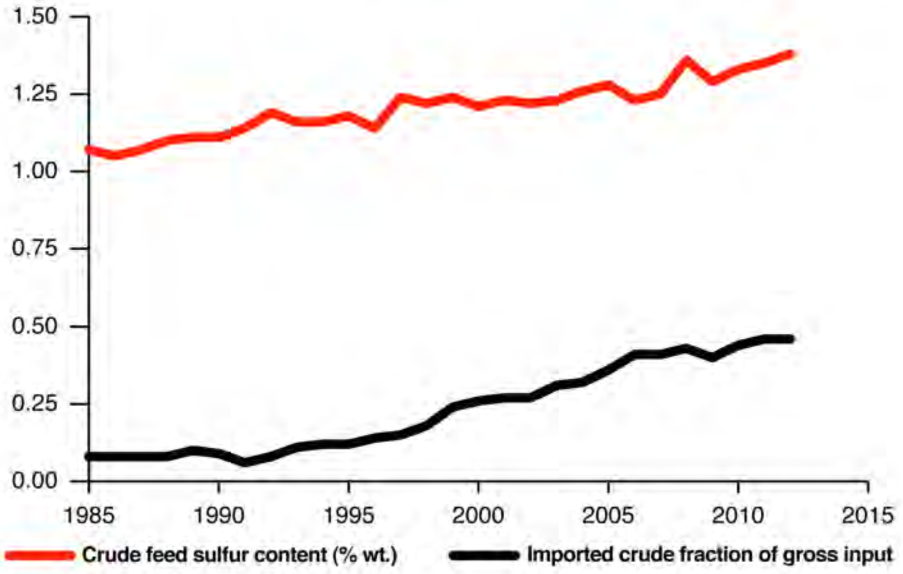

Chart 2. Sulfur and imports content of West Coast refinery crude feeds, 1985–2012
PADD 5 data from the U.S. Energy Information Administration (www.eia.gov/petroleum/data.cfm).

19. This new, dense crude slate likely will include more oil derived from "tar sands" bitumen. The project would commit the refinery to coker feed-rich crude over a period when the worldwide portion of high-density crude supplied by "heavy oil" and bitumen is likely to grow dramatically.[28] Bitumen has already come to dominate crude production in Canada,[29] the largest source of U.S. crude imports.[30] Moreover, crude can account for up to 90% of a refinery's operating costs,[31] and tar sands bitumen is price-discounted (due in part to delivery constraints),[32] so Phillips 66 is incented to run it, especially since the company's affiliates produce two of the bitumen blends shown in Table 3.[33] Indeed, recent major projects expanded the Rodeo facility's capacity to run more of these oils.[34] It now has vacuum distillation capacity to process a crude slate with atmospheric residua yield as high as 73% of the barrel, and coking capacity to process a slate with vacuum residua yield as high as 39% of the barrel,[35] which is more than enough to run the bitumen blends shown in Table 3.

20. Exactly what new crude blends to run is typically analyzed intensively based on many dozens of factors, but it is clear that the refinery will seek to run near capacity[36] and will continue to match blends of oils[37] to its processing capacities. Processing analysis for a blend of Western Canadian Select (WCS) and Alaskan North Slope (ANS) crude oils that the refinery could run is summarized as a hypothetical example in Table 4. In this simplified example, the refinery sells 12,000 b/d of the naphtha it distills from 120,000 b/d of WCS to other refiners, purchases 11,200 b/d of ANS gas oil, and runs its

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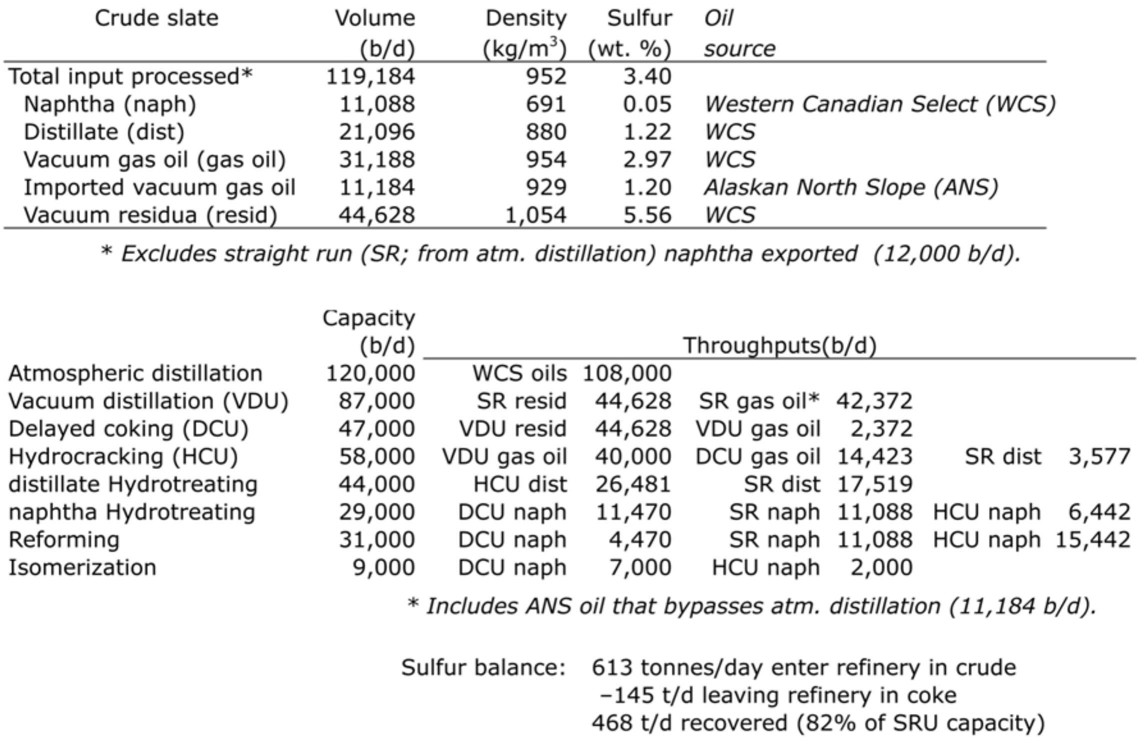
[28] <u>See</u> Meyer et al., 2007. *Heavy oil and natural bitumen resources in geologic basins of the world.* U.S. Geological Survey Open-File Report 2007–1084; <u>see</u> also Kerr, 2009.
[29] ERCB st 98–2009. *Alberta's Energy Reserves 2008 and Supply/Demand Outlook 2009–2018.* Energy Resources Conservation Board, Calgary. <u>See</u> pp. 2–6; <u>see</u> also *Oil & Gas Journal,* 2007.
[30] EIA, 2013. (http://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_epc0_im0_mbbl_a.htm).
[31] *Interim Investigation Report, Chevron Richmond Refinery Fire.* U.S. Chemical Safety and Hazard Investigation Board. Adopted 19 April 2013. (CSB, 2013.) <u>See</u> page 33.
[32] <u>See</u> Fox, 2013; and Goodman, 2013. (NRDC expert reports on Valero Crude by Rail Project.)
[33] <u>See</u> Canadian Crude Monitoring Program (www.crudemonitor.ca): Christina Dilbit Blend ("produced at the jointly owned Cenovus Energy Inc. and ConocoPhillips Christina Lake SAGD facility"); and Surmont Heavy Blend (50% owned, and operated by, Conoco Phillips Canada).
[34] <u>See</u> Strategic Modernization SCH #2002122017; Clean Fuels Expansion SCH #200509028; Marine Terminal Offload Project (ERM & BAAQMD, 2012); and DEIR at 3-19/20, 5-4/5-7.
[35] Based on process vs. crude capacities reported as of 1/1/13 by *Oil & Gas Journal* (2012).
[36] U.S. refineries ran at 90% of capacity on average since 1990 (www.eia.gov/petroleum/data).
[37] In addition to California and Alaska, the SFR processed oils from Canada and 20 other countries during 2004–2012 (EIA Imports Analysis).

Table 4. Example SFR refinery crude slate blending tar sands and conventional oils.



Crude slate	Volume (b/d)	Density (kg/m^3)	Sulfur (wt. %)	*Oil source*
Total input processed*	119,184	952	3.40	
Naphtha (naph)	11,088	691	0.05	*Western Canadian Select (WCS)*
Distillate (dist)	21,096	880	1.22	*WCS*
Vacuum gas oil (gas oil)	31,188	954	2.97	*WCS*
Imported vacuum gas oil	11,184	929	1.20	*Alaskan North Slope (ANS)*
Vacuum residua (resid)	44,628	1,054	5.56	*WCS*

** Excludes straight run (SR; from atm. distillation) naphtha exported (12,000 b/d).*

	Capacity (b/d)	Throughputs(b/d)					
Atmospheric distillation	120,000	WCS oils	108,000				
Vacuum distillation (VDU)	87,000	SR resid	44,628	SR gas oil*	42,372		
Delayed coking (DCU)	47,000	VDU resid	44,628	VDU gas oil	2,372		
Hydrocracking (HCU)	58,000	VDU gas oil	40,000	DCU gas oil	14,423	SR dist	3,577
distillate Hydrotreating	44,000	HCU dist	26,481	SR dist	17,519		
naphtha Hydrotreating	29,000	DCU naph	11,470	SR naph	11,088	HCU naph	6,442
Reforming	31,000	DCU naph	4,470	SR naph	11,088	HCU naph	15,442
Isomerization	9,000	DCU naph	7,000	HCU naph	2,000		

** Includes ANS oil that bypasses atm. distillation (11,184 b/d).*

Sulfur balance: 613 tonnes/day enter refinery in crude
−145 t/d leaving refinery in coke
468 t/d recovered (82% of SRU capacity)

Crude quality data from Canadian Crude Quality Monitoring Program (www.crudemonitor.ca) and publicly reported assays for ANS crude (*Oil & Gas Journal;* ExxonMobil and BP web sites). Refinery process capacities as of 1 January 2013 from *Oil & Gas Journal* (2012). Delayed coking yield based on typical yield reported for dense (1,044 kg/m^3) vacuum residua feed (see Tables 7.1-2 and 7.1-6 in Myers, 1986) and typical North American petroleum coke density (see Table S5 in Karras, 2010). Internal refinery hydrocarbon flow volumes may vary with varying volume expansion/loss effects in conversion processing. Capacities shown include the company's Santa Maria operations, which are integrated with the Rodeo operations via transfers of intermediate products, facilitating import/export logistics for refinery input blending.

vacuum distillation, coking, hydroprocessing, reforming and isomerization units at full capacity on the resultant WCS/ANS blend. This hypothetical example assumes WCS delivery, and represents but one of perhaps thousands of blends that the company might analyze closely for feedstock performance and cost containment. Nevertheless, this example shows that a new tar sands-derived crude slate could be very dense (≈952 kg/m^3) and high in sulfur (≈3.4 wt. %).

21. Crucially, logistical costs of bringing tar sands oil into the refinery—while rail loading, pipeline, and pipeline-to-boat capacities remain bottlenecked[38]—emerge as a

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[38] See Fox, 2013; and Goodman, 2013. (NRDC expert reports on Valero Crude by Rail Project.)

barrier to processing much more tar sands oil at the San Francisco Refinery. By linking a major new profit stream from LPG sales to price-discounted coker feeds such as bitumen, while expanding total rail and wharf loading capacity, the project could breach this transport cost barrier, and increase tar sands crude inputs to the refinery.

22. A Phillips 66 web page presents a map depicting crude transport routes from the tar sands region of Canada to its SFR by rail, pipeline, and ship, and quotes Chairman and CEO Greg Garland among the following excerpted statements:

> "Advantaged crude sells at a discount relative to crude oils tied to the global benchmark … [and] include[s] heavy crude from Canada …
>
> 'We are looking at pipe, rail, truck, barge and ship—just about any way we can get advantaged crude to the front end of the refineries,' said Garland. …
>
> The next challenge for the company is identifying strategies to get more advantaged crude oil to its California refineries [which can run a wide range of crudes]."[39]

Separately, Garland disclosed that the company's "opportunity to improve performance in California is really around getting advantage crudes to the front end of the California refineries, its rail, its ship, it's *working on optimization of the cost structure and the export capabilities of those refineries.*"[40] (Emphasis added.) These disclosures support the evidence discussed in paragraphs 12–21 and shed some light on how expanding rail capacity, production capacity, and LPG sales revenue in a way that is locked into low-quality crude feeds could "optimize the cost structure" for getting cheap tar sands oil to the refinery. The DEIR omits these disclosures.

23. Among other problems, denser and more contaminated crude feeds can greatly increase refinery energy intensity, air emissions, toxic pollutant releases, flaring, and catastrophic incident risk. The DEIR does not disclose or describe these impacts.

24. Changes in the fuel burned to heat, pressurize, and power refinery process equipment that would result from the project are not described adequately in the DEIR. It acknowledges a substantial shift in fuels to be burned but does not report the chemical composition of the current mixture of gasses burned or the changed mixture to be

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[39] See: http://www.phillips66.com/EN/newsroom/feature-stories/Pages/AdvantagedCrude.aspx.

[40] Thomson Reuters DECEMBER 13, 2012 / 01:30PM GMT, PSX – Phillips 66 First Annual Analyst Meeting. (www.streetevents.com).

burned. Some of this fuel gas composition data is available,[41] but it is not included in, or analyzed by, the DEIR. The mixture of chemicals burned must be identified and analyzed to support complete and reliable estimates of project air emissions.

25. Similarly, as the project causes the refinery to burn more fuel for energy it lowers the fuel's heat content, changing combustion conditions when it is burned. The DEIR provides no information about changes in the equipment that would burn this changed fuel refinery wide. For example, it is troubling that the company first asserted the lower heat content of refinery fuel gas "will require alterations to the burners of 19 heaters to operate efficiently," but now asserts that "no changes to any burners are required at this time," without providing design capacity data for its burners requested by air officials.[42] The DEIR does not mention this issue or correspondence, but this type of data on combustion equipment that could be affected by project fuel changes must be reported and analyzed to support a complete and reliable analysis of project impacts on flaring.

26. The DEIR does not disclose a part of the project that would enable emission increases that could cancel out its claimed SO_2 emissions reduction. Phillips 66 seeks "emission reduction credits" that could be banked and then used later, allowing the refinery to increase emissions by the credited amounts. In its application for air permits submitted for this project eight months ago, the company references the SO_2 emission reduction associated with the project that also is asserted in the DEIR, and then states:

> "Phillips 66 requests 174.7 tons per year of SO_2 emission reduction credits (ERCs) for this reduction. Of this amount, 7.61 tpy will be used to offset project SO_2 increases so that there will be no net increase in SO_2 emissions from the project (see Table 3-1). The remaining 167.1 tpy of SO_2 (174 tpy minus 7.61 tpy) will be banked as ERCs."[43]

This part of the project, to increase emissions later, and this "no net increase" claim, contradict the DEIR's unqualified assertion that the project will result in reducing refinery wide SO_2 emissions "by at least 50%."[44] The DEIR does not propose any condition of approval requiring that the promised refinery wide emission reduction be

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[41] See project Air Permit Application attachments A-4 and A-7 (Air Permit App Atts A 4 & 7).

[42] See Phillips' letters of 30 April 2013 (page 1) and 28 June 2013 (page 14) responding to BAAQMD letters of 1 March and 21 May, 2013 advising that its air permit application for the project is incomplete, and presenting numerous data requests (Air Permit Correspondence).

[43] Air Permit Application at 17, Section 3.4 (Air Permit App Sections 1–3).

[44] DEIR at ES-2, 3-5, and 4.3-19.

permanent. It does not identify the now-apparent link, between undisclosed future activities, and this project that could allow those future activities to pollute. It does not evaluate what those activities entail, whether they are part of the project or related to it in other ways as well, why the future rebound in emissions seems necessary, how soon it might occur, or how long it might last. Omitting plans to enable emissions that the DEIR is at the same time asserting will be cut appears misleading. In any case, this part of the project conflicts with the project objective to reduce emissions that is stated in the DEIR.

27. Waste heat from burning fuel to operate the project would be transferred to San Francisco Bay by expanding "once-through cooling" (OTC) that sucks Bay water into the refinery and discharges it back to the Bay as thermal waste. The DEIR does not report how much more heat the project would dump into the Bay. Moreover, its analysis of Bay water use, which *should* indicate the extent of thermal and other impacts of the OTC expansion, underestimates the potential increase in OTC water and heat flows.

28. According to the DEIR, the OTC expansion to 57.6 million gallons/day (MGD) represents an increase of 12.2 MGD from a project baseline OTC flow of 45.4 MGD.[45] The DEIR asserts this 45.4 MGD baseline without any supporting documentation, but NPDES findings omitted from it show that average OTC flow never approached 45.4 MGD since at least 1985. See Chart 3. Further, the refinery was required to estimate impacts of related prior modifications on its OTC flow and estimated they would increase it to only ≈35.4 MGD.[46] Permit review analysis of post-modification continuous monitoring data to check on that estimate found OTC flow of ≈35.5 MGD in 2010, and by mid-2011 this monitoring showed a long-term average OTC flow of ≈38.3 MGD.[46] This evidence shows that the 45.4 MGD DEIR estimate inflates the project's OTC baseline. Based on the proposed OTC expansion to 40,000 gpm (57.6 MGD) and the most recent NPDES long-term average OTC flow (38.3 MGD), the project could use ≈19.3 MGD of Bay water. This more accurate OTC flow increment (19.3 MGD) exceeds the increment the DEIR calculated from its inflated baseline (12.2 MGD) substantially.

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[45] DEIR at 3-27; see also Phillips, 2012b at 23–24: The same 40,000 gpm post-project total and 8,500 gpm increase on a purported 31,500 gpm baseline is asserted without documentary support in both, but 40,000 gpm is the proposed OTC rate that would be implied by project approval.
[46] NPDES Permit R2-2011-0027 at F-53 and Finding II. B. 3; see also Table E-5.

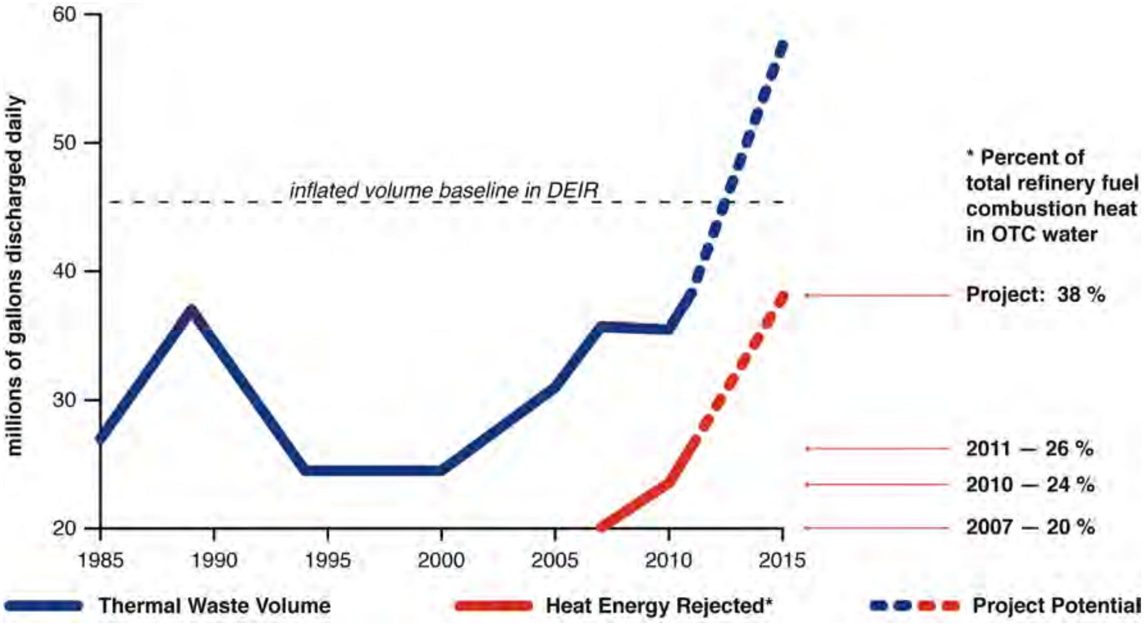

Chart 3. Rodeo facility combustion heat transfer to S.F. Bay. Thermal waste 1985–2011 volume data from NPDES orders R2-1985-029, 1989-002, 1994-129, 2000-015, 2005-0030 and R2-2011-0027; project potential volume from DEIR. Heat energy rejected is shown as a percentage of total refinery fuel energy (DEIR tables 4.6–1, 4.6–2) and is estimated based on volume entering OTC at 55 ºF (Reg. Monitoring Program, Davis Pt. Oct–June avg.) and exiting processing at 110 ºF before heat loss to the atmosphere and mixing in the retention system upstream of the outfall, and the specific heat of water (4.1868 J). Project potential heat percentage based on 2011 fuel use plus 140 MMBtu/hr for project steam.

29. Total heat rejected by OTC would grow, from ≈6.3–6.8 million gigajoules/year during 2007–2011 to ≈10.2 MM GJ/yr as a result of the project.[47] Waste heat rejected by the project flow increment (≈3.4–3.9 MM GJ/yr) would greatly exceed the total energy of additional fuel the DEIR states the refinery could burn for the project (1.23 MM GJ/yr).[48] Consequently, refinery wide reliance on OTC to reject waste heat would grow, from ≈20–26% of all fuel energy burned in the facility during 2007–2011, to ≈38% of post-project refinery energy use.[49] See Chart 3. The DEIR does not identify or explain the discrepancy between the fuel it says the project would burn and the heat its expanded OTC could carry, and it does not disclose this increased refinery wide reliance on OTC.

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[47] 1 gigajoule (GJ): 1 billion joules; 0.994 MMBtu. Waste heat rejected estimated as summarized in the caption of Chart 3. Note that the DEIR does not report the temperature of water exiting processing before entering the retention basin and mixing with other flows around the splitter; it states only that heat loss in those upstream steps will keep the OTC discharge at E-002 ≤ 110 °F.

[48] Based on 140 MMBtu/hr expanded steam boiler capacity (see DEIR at 3-20; 3-21) at 100% utilization. Note that even the DEIR's underestimated OTC flow (≈2.16 MM GJ/yr) would reject more heat than this expanded boiler firing would add: the DEIR does not identify the discrepancy.

[49] Based on annual fuel use in DEIR at 4.6-2, and project adding 140 MMBtu/hr to 2011 fuel use.

30. This increased reliance on OTC to carry heat from as-yet unidentified sources is consistent with an undisclosed increase in firing rates to process denser, higher sulfur crude feeds—which are known to increase refinery energy intensity.[50] It is consistent, also, with a shift from existing cooling towers to OTC—which might yield savings on cooling tower makeup water and chemicals.[51] Confirming or quantifying either or both possibilities may require cooling system design information that the DEIR does not provide. Regardless of its specific uses in cooling the refinery, however, the project's expansion of OTC would conflict with ongoing efforts to phase out and replace OTC.

31. In 2010 California adopted the Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling.[52] Among other things, this policy required power plant cooling systems to reflect the best technology available, encouraged them to use recycled water instead of estuarine water, and required most plants to cease OTC for units "not directly engaged in power-generating activities or critical system maintenance" by October 2011.[52] Importantly, oil refining is not addressed specifically by this policy at least in part because most California refineries replaced OTC with "closed loop" cooling towers long ago. In fact, the Rodeo facility is the only one of the five refineries lining the Bay that still uses this antiquated cooling technology[53]—and it has been since the Richmond refinery phased out and replaced OTC in the 1980s. The DEIR does not discuss this crucial context.

32. Work that could lead to phasing out and replacing OTC at the refinery has been ordered by the California Regional Water Quality Control Board. The Board ordered the refinery to prepare an engineering evaluation of replacing OTC, including a "conceptual design for a closed loop cooling tower system, including estimated costs (capital and operation) and construction timetable."[54] Phillips' 2012 response reported locations where two cooling towers could be built to replace OTC, conceptual designs for them, and estimated capital ($50 MM) and operating ($5.5 MM/yr) costs.[51] For context, this estimate suggests that the annualized cost over ten years represents only 0.2–0.3 % of the refinery's annual cost for $75/b–$115/b crude. The DEIR does not include or discuss this state order to evaluate replacing OTC or this refinery report indicating it can be done.

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[50] See Karras, 2010; Bredeson et al., 2010; Brandt, 2012; Abella and Bergerson, 2012.

[51] See *Cooling Tower Replacement Feasibility Evaluation* (Phillips Cooling Tower).

[52] As adopted by the State Water Resources Control Board on 1 October 2010 (SWRCB, 2010).

[53] Chevron R2-2011-0049; Shell R2-2012-0052; Tesoro R2-2010-0084; Valero R2-2009-0079.

[54] NPDES Permit R2-2011-0027 at Provision VI.C.2.f.

33. Evidence discussed in paragraphs 27–32 indicates that, by building onto and expanding the existing OTC system at the refinery, the project would foreclose an opportunity to replace OTC in the near term, and would instead continue and expand the use of this antiquated cooling technology. It would thereby result in the continuation of adverse impacts on aquatic life in San Francisco Bay that could otherwise be eliminated, in addition to the impacts from project increases in OTC flows. However, the DEIR seeks to evaluate only impacts from its (under)estimate of the increased OTC flow rate, further underestimating the project's potential impacts on the Bay.

34. Once-through cooling harms aquatic ecosystems by injuring or killing biota and degrading their habitats via entrainment,[55] impingement,[56] and thermal pollution.[57] In operation at design temperature, the severity of system- and site-specific impacts is generally proportional to OTC flow. Clearly adverse impacts have been documented from entrainment and at shoreline thermal discharge sites in San Francisco Bay,[58] but monitoring studies have yet to measure the full ecological impact of site-specific OTC applications. This is in part because of practical limitations in scientific tools. For example, reviews of a series of Bay OTC impact studies[59] found:

- Sampling techniques can be too aggressive for some species that become mutilated and unidentifiable or too passive to capture and account accurately for other species.
- Perceptions about the cost of comprehensive sampling lead to excluding many species or life stages—such as phytoplankton, invertebrates, eggs, and species present in very low abundance—and to attempts to measure "surrogate" species instead.
- Similarly, multi-year sampling is seldom done, but interannual variability changes the occurrence and abundance of many species affected by OTC in estuaries like the Bay.
- Sampling and data management designs must anticipate seasonal and spatial variation in the abundance of various species and life stages, but the site-specific timing of such changes is difficult to predict in many cases and may be impossible to predict for some poorly studied species.

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[55] The organism enters into the cooling system with water drawn through the intake screens.
[56] The organism is held against the intake screen by the force of the water flowing into the plant.
[57] Habitat is degraded or lost to various species when the ambient water temperature rises locally.
[58] For example, Mirant Corp. expected aquatic plant and invertebrate species to rebound if its Potrero power plant's thermal discharge was removed from a shoreline outfall (*Construction and Thermal Impacts First Quarter Larval Fish Assessment, 2001-2002*), and entrainment in the 226 MGD Potrero OTC flow was shown to kill an estimated 241–321 million larval fish annually (CBE, 2006). Impacts from the project's 57.6 MGD flow may be different from those of that different OTC system in another part of the Bay, and lesser or greater proportionate to its flow.
[59] See CBE, 2006.

- Taxonomic identification, especially in samples with small numbers of nonabundant or mutilated organisms among large numbers of another species, requires judgment.
- Rates of survival to reproductive age for larvae or juveniles affected by entrainment are generally not measured directly, and are instead inferred from generalized life history data that may be inaccurate or incomplete for certain species or populations.
- Indirect impacts, such as those from loss of forage (food supply) for another species, may be significant, but are difficult to measure and generally are not measured.
- Undersampled species may disproportionately affect the ecological system studied.
- Measurement limitations—such as those mentioned here as well as sampling losses and other anomalies—must be tracked and interpreted in analysis of the data.

Thus, OTC impact studies involve many judgments that are ultimately subjective and yet may determine whether impacts are detected. Compounding the problem in another way, these studies are typically sponsored by plant operators who prefer to avoid replacing OTC. For these reasons, the best practice standard for environmental review of OTC impact monitoring studies includes some form of independent peer review during study design, study implementation, and interpretation of study results. The DEIR does not identify any of these limitations in biological monitoring studies of OTC.

35. No description of the biological effects of OTC *expansion* is provided in the DEIR. Its full discussion of biological effects from the OTC system itself—except for admitting that endangered species are at increased risk of adverse impact—is one long sentence about an old study of intake impacts:

> “The Refinery documented the effectiveness of the wedgewire screens in 2006, estimating that their configuration virtually eliminated impingement of adult and juvenile fishes and significantly reduced entrainment of larval fishes; the location of the intake structure provides effective sweeping flow velocities that, combined with low through-screen velocities at maximum pumping rates, minimize the entrainment of larval fishes.”[60]

The DEIR thus does not discuss the extent to which this study: measured all potentially impacted species; used sampling techniques that were effective for all species targeted; identified all targeted species in each sample accurately; monitored or accounted for the great interannual variability of the estuarine impact zone; captured seasonal and spatial variability in OTC impacts; measured long-term survival of entrained or impinged biota and indirect impacts such as forage reduction on other species; measured effects on non-abundant species present, or made proper judgments about these issues in data analysis.

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[60] DEIR at 4.4-27. A thermal impact study is not yet done: <u>see</u> Phillips thermal ext 1, 2.

The DEIR does not actually say whether this study collected *any* biological samples. Moreover, this study of 2006 OTC flow conditions does not represent the project's potential for much greater long-term future OTC flow conditions. See Chart 3. The DEIR obscures this important fact by its false assumption that only its underestimated flow increment (12.2 MGD), rather than the full post-project OTC flow (57.6 MGD), should be assessed for potential impacts. The project would increase OTC flow more than the DEIR's inflated baseline discloses *and* would cause the full expanded OTC flow to continue when it otherwise could be eliminated, as discussed in paragraphs 27–33. Accordingly, this 2006 study, and the DEIR itself, does not describe the biological implications of the expanded OTC flow that would result from the project.

36. Instead of describing these environmental implications of the project, the DEIR asserts that any impacts from the OTC expansion will be less than significant because of NPDES permit limits.[61] This assertion is contradicted by facts that the DEIR does not disclose, but in a vain attempt to support it, the DEIR makes a series of erroneous statements that describe the project and its setting inaccurately. In a paragraph referring to an allowable "maximum discharge temperature of 110 ºF" the DEIR asserts:

> "By using sufficient cooling water to ensure that maximum temperatures remain in compliance with the NPDES permit, no significant impacts on special-status fishes would occur."[62]

This statement is clearly erroneous because a large enough volume of 80–110 ºF thermal waste would injure or kill fish that are adapted to 55 ºF water,[63] but it also is misleading. This statement only makes sense if the heat in the 57.6 MGD discharge diffuses rapidly. The statement thus invites the inference that the Rodeo OTC discharges via a deepwater diffuser—a technology so universally required that a proper environmental review would surely note the anomaly if that was not the case—but that is not the case. The antiquated OTC discharges from a shoreline outfall. See Map 1 discharge point 003. Consequently, the thermal waste receives little or no initial dilution, greatly exacerbating its localized impact, and NPDES permit limits allow that, but the DEIR does not disclose these facts.

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[61] DEIR at 4.4-27 and 4.4-28; see also DEIR at 4.10-24. It is acknowledged that deferring to future actions by others to address impacts has serious policy and legal implications that require analysis beyond the scope of this report.

[62] DEIR at 4.4-28.

[63] This water temperature (≈55 ºF) is typical in the ambient water of San Pablo Bay near the OTC outfall. See Regional Monitoring Program, Oct–Jun average for Davis Point (Site BD40).

Map 1. Rodeo facility outline, discharge points, and intake points. Attachment B to NPDES Permit, Order R2-2011-0027. The left-most circle containing a cross denotes discharge point E-003.

37. Compounding its error, the DEIR further explains its reliance on NPDES limits by asserting that "the NPDES permit establishes maximum once-through volumes."[64] This statement is untrue. The permit limits several pollutants in the OTC thermal waste discharge at outfall E-003 but flow volume is *not* limited by this permit.[65] The 56% increase in OTC flow during 2000–2011, a period when two permit orders document concerns over OTC impacts that remain unresolved,[65] demonstrates the fallacy of the DEIR's flow limit assertion poignantly. See Chart 3. The DEIR's misplaced focus on permit limits also obscures the permit's ongoing effort to develop closed loop cooling to replace OTC and eliminate its impacts—a crucial effort that the project would foreclose.

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[64] DEIR at 4.4–23; see also 4.4-27.

[65] All NPDES permit limits on the OTC (E-003), for °F, TOC, Cl, Cu, Ni, Zn, and dioxins, are given in tables 8–11 of NPDES Permit Order R2-2011-0027, and flow volume is *not* among them. Provisions VI.C.2 d–f of this Order, and provisions D.9 and D.10 of Order R2-2005-0030 document ongoing, unresolved concerns regarding impacts of the OTC during this period.

38. Remarkably, the DEIR admits that the project's expansion of once-through cooling has the potential to adversely impact threatened or endangered fish species without specifying which ones. It states: "[S]pecial-status fish species identified in Table 4.4-1 that may be present along the Refinery shoreline on a seasonal or year-round basis … are potentially at risk of being entrained in intake pipes, and this risk could increase due to the increased volume of once-through water that would be required under the Project. … . These fishes [also] could be subjected to an increased risk of injury, death, or habitat reduction at effluent discharge locations"[66] The DEIR defines "special-status fish species" to include, among others, the Southern DPS–Green Sturgeon, the Central California Coast and Central Valley DPS–Steelhead, the Central Valley Spring-run Chinook Salmon, and the Winter-run Chinook Salmon—all federally listed threatened or endangered species.[67] The severity or importance of this potential impact may depend in part upon which of the endangered or threatened species face this project risk, but the DEIR does not provide that information, or at least does not do so in an easily understandable form.

39. LPG taken from cracking byproduct gases and treated in the refinery would be stored in new propane and existing butane tanks before loading to railcars via two new rail spurs and a new two-sided loading rack, according to the DEIR project description.[68] The DEIR acknowledges that although this occurs very rarely, the potential exists for a catastrophic failure of an LPG storage vessel such as a "boiling liquid expanding vapor explosion."[69] However, the DEIR describes it as occurring too rarely to warrant analysis of mitigation, and describes cooling the LPG storage tanks instead of pressurizing them (which would eliminate this catastrophic risk) as "infeasible" because of the added costs for electricity and a new flare.[69] Impacts of such an incident could be catastrophic and irreversible. The DEIR does not include or describe the documented Process Hazard Analysis or Inherently Safer Systems Evaluation required by the County Industrial Safety Ordinance (ISO) for the project, and thus does not disclose that those requirements contradict its analysis.

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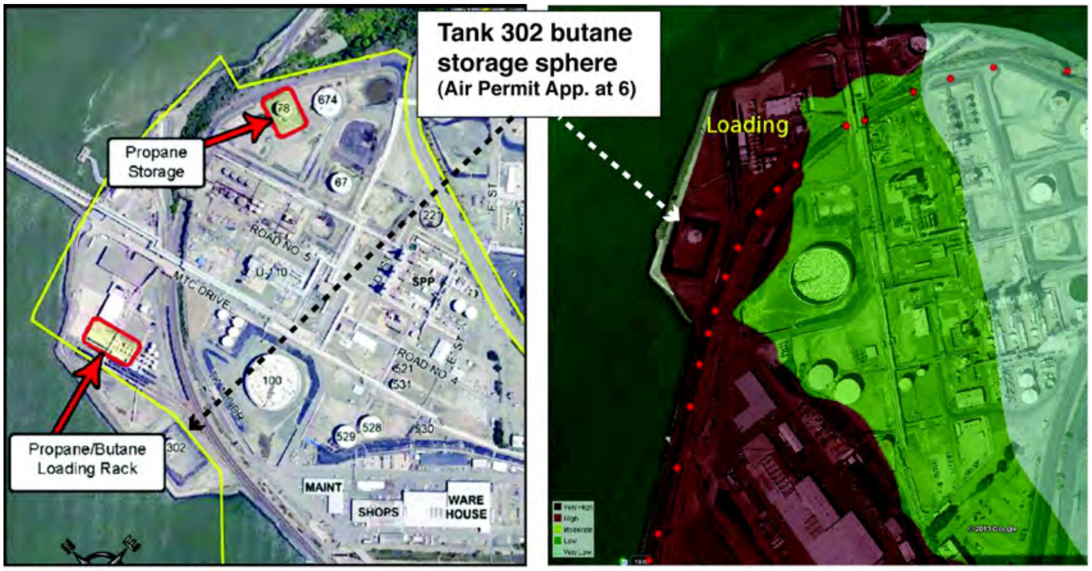
[66] DEIR at 4.4-27. The quote continues, with a qualifier regarding the thermal impact reading *"if those temperatures exceed permitted discharge limits."* However, the DEIR wrongly assumes the increased volume of hot shoreline discharge that receives little or no dilution is controlled by permit volume limits and will not impact the fish, as discussed in paragraphs 36 and 37.

[67] DEIR at 4.4-9 and 4.4-10 (Table 4.4-1).

[68] DEIR at 3-6, 3-17, 3-21 and 3-25.

[69] DEIR at 49-2, 4.9-18, 4.9-19 through 4.9-22, 6-5.

40. Process hazard analysis (PHA) requires, among other things, rigorous determination of the site-specific likelihood of particular hazardous consequences.[70] "Conducting a comprehensive hazard review to determine risks and identify ways to eliminate or reduce risks is an important step in implementing an inherently safer process."[70] For example, a comprehensive PHA for the project's new propane and additional butane storage would identify and analyze the increased probability of catastrophic failure caused by soil liquefaction in an earthquake—a serious site-specific risk in the seismically active East Bay. At least one of the tanks that would store project LPG is sited on a shoreline plot[71] at high risk for soil liquefaction. <u>See</u> Map 2. This would increase the probability of catastrophic failure involving LPG storage over time. The DEIR, however, estimates this probability based on generalized industry-wide estimates of its frequency.[72] Because it does not describe or evaluate the site-specific conditions, the DEIR underestimates the probability of a catastrophic event.



A. Detail from DEIR Figure 3-3. **B. Seismic shaking / liquifaction hazard overlay**

Map 2. Project-related LPG storage near loading, and earthquake liquefaction hazard
Note the two plate's different orientation to North. Plate B from Ed Tannenbaum and Danielle Fugere. Burgundy shading in the area near the shoreline (Plate B) indicates very high liquefaction hazard.

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[70] CSB, 2013 at 40; <u>see</u> also CSB at 32.
[71] Project butane would increase this and other tanks' throughput. DEIR at 3-21/26, 4.5-7, 4.9-1.
[72] DEIR at 4.9-18; <u>see</u> also AICE, 1989 at 205.

41. County Hazardous Materials Program staff have informed Phillips 66 that they expect "revised siting studies with placing new equipment and associated impacts to existing processes including locations that house personnel (e.g., control rooms, admin buildings)" for the project.[73] These studies would detail what comparing maps 1 and 2 shows: Project-related LPG storage is located relatively close to a concentration of other vessels containing flammable hydrocarbons, the administration building, parking lots, and thus numerous plant personnel. However, the DEIR describes only "moderate" consequences of a catastrophic LPG storage incident, and explains that this is "primarily due to the large distances to the *off-site receptors* (730 to 1340 m.)."[74] *(Emphasis added.)* Its incomplete description of the project's setting causes the DEIR to ignore workers and underestimate the magnitude of this catastrophic risk.

42. Cooled instead of pressurized liquefied gas storage could eliminate the risk of catastrophic LPG storage vessel explosion. Because it is practicable and safer than the proposed pressurized storage for this identified catastrophic hazard, cooled storage could be defined as an inherently safer system with respect to this hazard. In contrast to the DEIR's failure to analyze this mitigation, the ISO *requires* documented inherently safer systems analysis for new processes and facilities.[75] The U.S. Chemical Safety Board recommends that inherently safer technology should be implemented to drive risk as low as reasonably practicable (ALARP), and notes that: "It is simpler, less expensive, and more effective to introduce inherently safer features during the design process … rather than after the process is already operating."[75] Furthermore, in contrast to the DEIR's description of cooled storage as "infeasible" due to the costs of additional electric power and a new flare, the ISO seeks to implement inherently safer solutions "to the greatest extent feasible."[75] There is no cost exemption for affordable cooled storage. The DEIR's description of catastrophic hazards is in error, and its failure to describe inherently safer systems requirements for the project obscures this error.

43. CHMP staff also expect documented human factors evaluations of processes and procedures for the project.[73] These could include, among other things, evaluation of "safety culture" problems that may incent company management to defer safety measures

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[73] 11 July 2013 letter from Michael Dossey to Jim Ferris, Phillips 66 (CCHMP–Phillips). The DEIR does not include these process-specific studies or evaluations or discuss their results.

[74] DEIR at 4.9-21.

[75] ISO § 450–8.016(d)(3); see also CSB, 2013 at 40, 45–47, and 55. The DEIR does not include or discuss the Chemical Safety Board's findings, or even its recommendations to the County.

as a shortsighted way to cut costs.[76] But the DEIR does not include or report on this human factors evaluation, and although it is relevant, the DEIR does not discuss this safety culture issue. Chevron management deferred at least six worker requests to inspect or replace a piping circuit over ten years, before that severely corroded pipe ruptured catastrophically in the 6 August 2012 Richmond refinery fire.[77] In another example of poor safety culture, the BP Texas City refinery explosion in March 2005 killed 15 people and injured 180 after BP management—in part to boost profits by avoiding short term costs—deferred replacement of a blowdown stack with a flare.[78] Similarly, the DEIR assumes a bias in favor of avoiding the cost of a flare in its inappropriate failure to analyze identified mitigation for a catastrophic hazard presented by the project.

44. Chemical spills, fires, and explosions at U.S. oil refineries killed at least 30 and injured at least 15,211 workers and nearby residents since 1999.[79] At least 49 upset "emergency" incidents occurred at Bay Area refineries since March 2010.[80] At least 30 such incidents occurred at California refineries in a recent five-month span.[81] The DEIR does not describe or discuss this important context for review of project hazards.

45. Exporting 8,000 b/d of additional LPG from the refinery for sale instead of burning that propane and butane in its fuel gas would change the location of emissions from LPG created by refinery processes. Although selling this LPG for purposes that obviously include burning it is the primary objective the DEIR states for the project, the DEIR does not identify or describe the resultant off-site impacts or provide information about specific end uses of this LPG.[82] Those potential emissions are substantial: the

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[76] Chevron Safety Audit Oversight Committee, 2013. Audit Scope of Work.
[77] CSB, 2013: see esp. 36–42.
[78] Chemical Safety Board incident investigation (CSB, 2005). See esp. page 253: In one instance BP managers decided on in-kind replacement of the hazardous design in part to "maintain profits" by avoiding new source standards that likely would have required connecting to a flare.
[79] U.S. Chemical Safety Board incident investigation reports (www.csb.gov). Injuries include hospital visits associated with the 2012 Chevron Richmond refinery fire.
[80] Flare causal analyses submitted to Bay Area AQMD pursuant to Rule 12-12, §406.
[81] Labor Occupational Health Program, U.C. Berkeley, 2013 (LOHP).
[82] BAAQMD asked for the end uses of this LPG but like the DEIR, the company did not report them (see Air permit correspondence). Because of this nonreporting only a "potential to pollute" estimate is possible, but it is reasonably foreseeable that virtually all project LPG exports could be burned. Combustion activities (residential, C4 gasoline addition, industrial and recreational) are the primary end use of LPG sold nationally, and markets are highly regional; LPG use for petrochemical feedstock is highly concentrated in the Gulf Coast. Shipping costs to sell Rodeo LPG in the Gulf Coast would make it less competitive than Gulf Coast LPG supplies.

DEIR estimates that the LPG the project would remove from refinery fuel gas would emit greenhouse gases (GHG) at a rate of 759,244 tonnes/yr.[83] But instead of identifying, describing, or accounting for the resultant off-site impacts, the DEIR subtracts this amount from its project GHG emission estimate. The DEIR thereby assigns offsite LPG emissions a value of zero—even though it accounts for project emissions from outside the refinery gate for transport, and electricity generation—erroneously calculating a net decrease in GHG emissions (–325,978 tonnes/yr) when the correct net emissions, by its own estimate, total 433,266 tonnes/yr (–325,978 + 759,244).[83] Thus, project emissions could exceed the 10,000 tonnes/yr threshold of significance for GHG emissions used by the DEIR substantially. The DEIR does not identify a potential impact that would be significant, in part because it does not describe LPG environmental implications of achieving the project's main stated goal outside the refinery gate.

46. Byproduct coke production would increase along with cracked LPG gases for the project, but the DEIR does not say how much, or whether this additional petroleum coke will be exported, burned in the refinery, or both. Increased coking of denser feeds might increase coke production by thousands of barrels/day, and coke burns much dirtier than the gases the DEIR assumes the refinery will burn.[84] Burning the extra coke created by the project in place of other refinery fuel could increase refinery emissions substantially.

47. The DEIR does not explain that the company's Rodeo Facility (RF) and Santa Maria Facility (SMF) are two parts of one integrated refinery. The SMF and RF are linked by a pipeline sending crude and intermediate oils between them,[85] their processes are integrated to a capacity that neither can achieve alone,[86] and Phillips 66 reports them as a single processing entity to industry and government monitors[86] that is called the "San Francisco Refinery."[85] Omitting all of this, the DEIR also fails to explain the extent to which this project, and the concurrent SMF expansion to increase production and pipeline shipments to Rodeo,[85] are two parts of a single, larger, project that remains undisclosed.

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[83] See DEIR at 4.8-18, Table 4.8-3

[84] Denser feeds might increase coke yield on coker feed volume by ≈10% (see tables 7.1-2, 7.1-6 in Meyers, 1986), not counting the effect of increasing coker feed volume. As compared with CO_2 emissions of ≈67.7 kg/GJ fuel gas and ≈56.0 kg/GJ natural gas, burning petroleum coke emits CO_2 at a rate of ≈108 kg/GJ. See Karras, 2010 at Table S1.

[85] SMF EIR 2012 Excerpts (attached). See esp. pages 2-1 (describing SMF–Rodeo integration), 2-11 (processes, and intermediates sent to Rodeo), 2-25 (project would increase deliveries of oils to Rodeo via pipeline), and 2-26 (project potential for 408,255 tons/yr increase in coke produced).

[86] See *Oil & Gas Journal*, 2012; and EIA Ref. Cap. 2013. See also orders R2-2011-0027 and R3-2007-0002. Comparing the references shows "Rodeo" capacities reported to EIA include SMF.

Project Impacts on the Environment

48. Project emissions would exceed a climate significance threshold, as the DEIR's emission estimates show, when its failure to account for emissions from burning project LPG is corrected. See paragraph 45. A check on its estimates, accounting for the 8,000 b/d of LPG (464,243 m^3/yr) sold and replaced by natural gas for refinery fuel, confirms that project GHG emissions would exceed the significance threshold established in the DEIR by more than 40 times. See Table 5. These observations make sense because oil refining emits more GHG than any other industry in California,[87] and the project would increase fossil fuel combustion associated with the refinery's activities substantially.[88] Among other potential measures to lessen or avoid this impact, the County could consider requiring that refinery use of electricity from the grid be purchased from renewable, rather than fossil-fueled, generation sources.

Table 5. GHG emissions from project LPG and natural gas to replace it in fuel gas

	DEIR estimate (CO_2e)[a]		CBE estimate (CO_2)[b]	
	LPG	natural gas	LPG	natural gas
volume (m^3/yr)	464,243	310,000,000	464,243	313,000,000
energy (GJ/yr)	11,230,541	11,230,541	11,900,000	11,900,000
emissions (tonnes/yr)	759,244	592,761	782,000	666,000
change in off-site LPG emissions		759,244		782,000
change from replacing LPG in fuel gas		-166,483		-116,000
net of other project emissions identified[a]		-159,495		-159,495
Total project emissions identified in DEIR		**433,266**		**506,505**
Threshold of significance from DEIR		10,000		10,000

LPG volume shown as liquid, from DEIR Table 3-2. (a) DEIR data from Table 4.8-3, except energy estimate from page 4.8-16 and natural gas volume estimate from Table 3-2. Other project emissions: boiler, mobile source and indirect emissions minus shutdown credit. (b) Based on natural gas energy equivalent to project LPG volume and heat contents (25.62, 0.038 GJ/m^3) and CO_2 emission factors (65.76, 55.98 kg/GJ) for LPG and natural gas, respectively, from Table S1 in Karras, 2010.

49. Stored under pressure, project gases could explode. Because predicting when this catastrophic and irreversible consequence might occur is ultimately speculative, and a safer design that might eliminate this hazard could be precluded after the project is built, the project as proposed would create an *inherent hazard*.[89] The project's failure to

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[87] See CARB, 2013.
[88] Project LPG sales burned elsewhere and replaced with natural gas onsite would represent ≈44% of all fuel energy burned in the refinery in 2011, based on DEIR data (see pages 4.6-2, 4.8-16).
[89] See: CSB, 2013 at 40–48, 55.

demonstrate the use of inherently safer systems (ISS)—including cooled instead of pressurized storage, which would eliminate this catastrophic explosion hazard—through a process hazard analysis (PHA)[90] would conflict with the Industrial Safety Ordinance. Therefore, project gas storage under pressure would result in a hazard impact. The DEIR failed to identify the significance of this impact because its analysis ignored hazardous siting conditions and PHA and ISS requirements, and rejected analysis of an inherently safer measure that could avoid a catastrophic hazard based on cost, contrary to safety best practice and the Industrial Safety Ordinance. See paragraphs 39–44.

50. Pressurized gas storage explosion hazard resulting from the project can be mitigated but the DEIR did not complete its analysis of this mitigation opportunity. The County could consider developing an appropriate permit condition requiring cooled storage of propane and butane stored as a result of the project. Developing an appropriate permit condition would require reporting and evaluation of the PHA and documented ISS analyses that were not reported or addressed in the DEIR.

51. Expansion of the existing once-through cooling system would conflict with state plans and policies to phase out and replace this antiquated technology and foreclose an opportunity to replace the system in the near term via ongoing work to implement those plans and policies. Increased impingement, entrainment and thermal waste impacts that would result from the project would adversely impact aquatic biota and have the potential to injure or kill members of the remaining populations of threatened or endangered fish species that depend upon aquatic habitats in the vicinity of the refinery. Therefore, the project would adversely impact the biological resources of the San Francisco Bay-Delta ecosystem in conflict with state plans and policies.

52. The DEIR failed to identify the state plans, policies, and ongoing work the project would conflict with and foreclose by expanding the once-through cooling system. Due to these errors and its assumption of an erroneous project baseline it targeted only a fraction of the intake and discharge flow that would result from the project for its impact analysis. The DEIR reported no biological analysis of actual system effects that includes data representative of the expanded system. Its conclusions ultimately relied on a description of flow, heat, and discharge limitations that is demonstrably incorrect. As a result, it did

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[90] No documented PHA or ISS is included in the DEIR, and County safety staff still sought these analyses, *including for cooled storage*, as of 11 July 2013. CHMP-Phillips071113; DEIR at 6-5.

not identify the significance of this impact. See paragraphs 27–38. The County could consider, among other measures to lessen or avoid this impact, requiring replacement of the antiquated once-through cooling system with closed loop cooling towers.

53. Sulfur dioxide (SO_2) emissions could increase, instead of decreasing as the DEIR claims, and this impact could be significant, but the DEIR did not analyze, or include information needed to analyze, this potential impact. The project outlined *in concept* might cut emissions substantially, but the DEIR's claim that refinery wide SO_2 emissions will be cut by 50% is wrong for several reasons. The project application for "emission reduction credits" to *increase* SO_2 emissions by 174.7 tons/yr that Phillips asserts will be used to achieve "no net increase" in project emissions would foreclose an emissions cut. See paragraph 26. Further, if the actual emissions cut from treating and replacing fuel gas is less than 174.7 tons/yr, emissions could increase. The extent of this potential increase cannot be quantified because data to support the emission credits—such as fuel gas hydrotreating specifications, and pre- and post-project fuel gas balances showing the composition and flows of gases among process units—is not included in the DEIR.

54. Importantly, this undisclosed change in the project that would foreclose the promised SO_2 emissions reduction conflicts with the DEIR's stated project objective to reduce emissions. The County could consider developing a land use permit condition that ensures the 50% reduction in refinery wide SO_2 emissions identified in the DEIR will be real, measurable and permanent. Developing an effective condition could be expected to require, among other things, analysis of the fuel gas composition and petroleum coke disposition data that is not disclosed in the DEIR (see paragraphs 24 and 46).

55. Flaring could be caused by fuel gas quality upsets resulting from the project because it lowers the heat content of gases burned throughout the refinery without upgrading equipment designed to burn gases with higher heat content. Fuel gas quality upsets, including those involving low heat-content gases, have caused significant flare episodes at the refinery repeatedly.[91] The company's shifting statements about whether existing burners should be or will be upgraded underscore the potential for increased frequency and magnitude of this type of flaring.[92] Flaring from fuel gas *quality* upsets can occur independently from that caused by fuel gas *quantity* upsets, and the DEIR did

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[91] Flare Causal Analysis excerpts; see also CBE, 2007. *Flaring Prevention Measures.*
[92] See paragraph 25; Air Permit Correspondence; see also paragraph 14.

not analyze or mitigate this fuel gas quality issue. Moreover, flaring episodes impact air quality and health via acute exposures around each episode,[93] so that fuel gas quality flaring from the project could cause significant impacts even if the project reduces flaring from fuel gas quantity problems. To support a complete and reliable analysis of impacts on flaring, specifications for the changed fuel gas quality and for all of the combustion equipment that could be affected by this change must be reported and analyzed.

56. Flaring likely would be caused by the crude switch resulting from the project. Three independent reviews following the refining of higher sulfur crude at Gulf Coast and Bay Area refineries found evidence for increased flaring and flare emission intensity from hydrocracker and hydrotreater upsets.[94] This potential impact would not be mitigated by project treatment of fuel gas because the emergency shutdowns of these high-pressure processes that initiate the flaring typically requires dumping their contents to flares, bypassing fuel gas treatment. Indeed, flaring is allowed in emergencies, despite known local air impacts,[95] as a last-resort emergency response safeguard *after* potentially catastrophic conditions begin to manifest. This flaring indicates a process hazard.

57. The DEIR did not describe or evaluate upset flaring or any other impact of the denser, more contaminated crude slate that likely would result from the project. The denser hydrocarbons disproportionately present in denser crude oils have many more carbon atoms, and much lower hydrogen : carbon ratios, than the gasoline, diesel, or jet fuel made from these oils. These dense hydrocarbons also have greater concentrations of contaminants—such as sulfur, nitrogen, nickel, vanadium, selenium, and naphthenic acids, among others—that are toxic, corrosive, poison process catalysts, or decompose in refining processes to form toxic and corrosive compounds such as hydrogen sulfide (H_2S). Density and contaminant content broadly correlate among well mixed blends of whole crude oils from many different locations and geologies.[96] But complicating assessment and further increasing the hazard, this correlation breaks down in the case of

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[93] See CBE, 2005. *Flaring Hot Spots;* BAAQMD, 2006 at 6–8.

[94] Subra, 2008; Karras, 2008; Dolbear, 2008 (Dolbear AG Summary). The concise notes from Dolbear's review inform the need to check for unanticipated hazards from crude switching: "This work forced me to think through this system again, and I conclude that, at least in the refineries in question, increasing contaminant levels do result in stressing the system to lead to upsets".

[95] Compare BAAQMD, 2006 at 6–8 (documenting flaring impact on nearby community) with BAAQMD Flare Control Rule 12-12 §101 (nothing in rule should be construed to compromise safety) and §301 (standard allows flaring in emergency to avoid potentially worse consequences).

[96] See Speight, 1991; Karras, 2010.

some individual crude oils that the project could lock the refinery into processing. In particular, partially pre-processed oils[97] and bitumen[98] derived from tar sands can be highly contaminated relative to their density.

58. Lower quality crude is an inherently more hazardous feedstock. Making engine fuels from its denser, hydrogen-poor hydrocarbons requires processing proportionately more of each barrel using severe carbon rejection (e.g., coking) and hydrogen addition (e.g., hydrocracking) and making that hydrogen, increasing refinery energy use and fuel burning for that energy.[99] Its greater contaminant content results in greater amounts of various toxic chemicals passing through the refinery into the environment, potentially increasing fugitive emissions of benzene and other toxics,[98] and in some cases boosting per-barrel releases of toxic trace elements by up to an order of magnitude.[100] The larger volume of toxic, flammable, and corrosive materials undergoing severe processing at high temperature and pressure further increases the frequency of process malfunctions and upsets over time, and the magnitude of these incidents when they occur.

59. Switching to higher sulfur crude was a causal factor in the disastrous Richmond refinery fire on 6 August 2012. See Chart 4. Sulfur corrosion of the pipe section that ruptured catastrophically in the incident (gray shading), sulfur in the gas oil running through this pipe (black line), and sulfur in the refinery crude feed supplying that gas oil (red line) are shown in this chart. The percent change from baselines is shown.[101] As sulfur increased in the crude, it increased in the gas oil distilled from that crude and running through the pipe, and sulfidic corrosion began to thin the wall of this pipe more than four times faster than before that dramatic sulfur increase. See Chart 4. This example of an ultimately disastrous feedstock substitution hazard applies to the SFR and the even more inherently hazardous crude feed that likely would result from the project.

60. Sulfur attacks metal equipment in contact with oil streams at temperatures above ≈230 ºC, causing thinning that leads to catastrophic ruptures, so that "sulfidic" corrosion "continues to be a significant cause of … incidents associated with large property losses

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[97] See Karras, 2010.
[98] See Fox, 2013.
[99] See Karras, 2010; UCS, 2011; Bredeson et al., 2010; Brandt, 2012; Abella and Bergerson 2012.
[100] See CBE, 1994; and Wilhelm et al., 2007.
[101] For example, sulfur increased by more than 50% in crude based on crude sulfur content > 1.5 wt. % (Aug 2011–Jul 2012 avg.) versus a baseline < 1 wt. % (1996 avg.). See Karras, 2013.

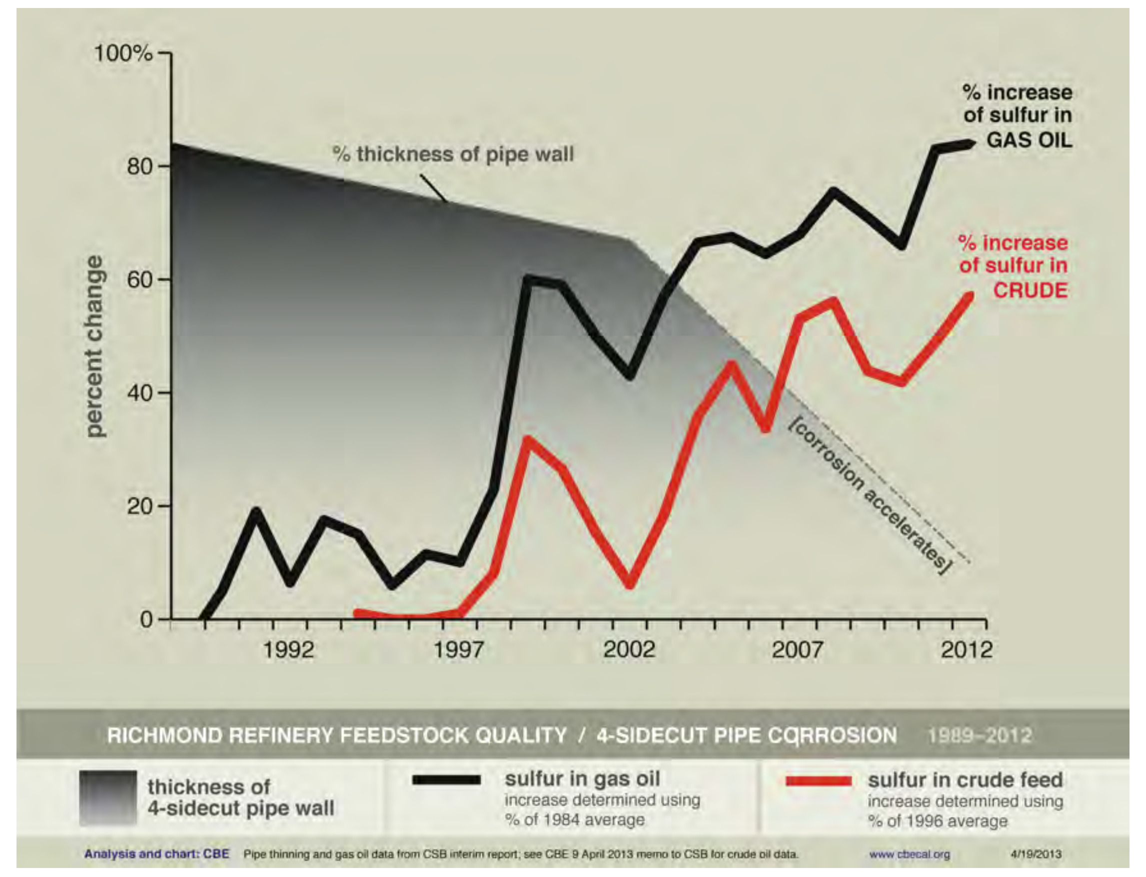

Chart 5. Richmond refinery feedstock quality / 4-Sidecut pipe corrosion, 1989–2012.
From testimony presented in the 19 April 2-13 U.S. Chemical Safety Board public hearing at Richmond, CA.

and injuries."[102] Sulfidic corrosion can occur anywhere in refineries where sulfur-bearing oils are processed this hot.[102] "Process variables that affect [sulfidic] corrosion rates include the total sulfur content of the oil, the sulfur species present, flow conditions, and the temperature of the system."[103] Higher sulfur crude feeds can accelerate sulfidic corrosion dramatically.[104] See Chart 4. All steels are attacked, but carbon steel, and carbon steel that has low silicon content, are particularly vulnerable.[104] U.S. refineries built before 1985 are especially vulnerable because they likely include low-silicon carbon steel equipment components.[104] Newer equipment can be similarly vulnerable because, perhaps in the rush to build and restart production, it may be made from inappropriately

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[102] API, 2009 at vii. See also pages 3–8, and 16; and CSB, 2013 at 29–30.
[103] CSB, 2013 at 16.
[104] See CSB, 2013 at 16–45; see esp. 33–36. see also API, 2009.

corrosion-vulnerable alloys mistakenly installed, and then operated because of this error.[105] Sulfidic corrosion is difficult to monitor: it may accelerate in a few small, vulnerable, yet critical components of refinery piping systems many miles long, requiring monitoring of 100% of the components, but that is costly and may not be performed.[106] Actions taken to cut energy costs have in some cases inadvertently exacerbated sulfidic corrosion.[107] Further, in addition to introducing another hazard, corrosion resulting from naphthenic acids (TAN) in the crude can exacerbate sulfidic corrosion.[108] Ignoring or failing to recognize the nature of this hazard is part of the problem—impacts of a new and different feedstock are at best difficult to predict, and past operating history is *not* a guide to the future hazard when a refinery switches to a new and high-sulfur crude.[109] The proposed project at SFR presents these aspects of this hazard.

61. Sulfur is likely to reach ≈3–4 wt. % in the new crude slate that would result from the project. See paragraphs 12–22. This could cause more aggressive sulfidic corrosion than the increase to ≈1.55 % sulfur that caused the catastrophic pipe failure in 2012 at Richmond. The new crude slate is also likely to include more high TAN tar sands oils that could further exacerbate sulfidic corrosion and create a new corrosion hazard.[110] The Rodeo facility was built before 1985: carbon steel equipment that is especially vulnerable to sulfidic corrosion is likely present in the plant. The project as proposed documents no positive materials identification program that is addressing this vulnerability. Nor does it document any management of change, process hazard, or inherently safer systems analysis of this hazard, in conflict with the ISO and industry standards.[111] The project, as proposed, would create a catastrophic hazard resulting from switching to a new crude and rely, in essence, on past operating history to address this hazard. That is unsafe.

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[105] Incorrect alloys for corrosion resistance may have been installed mistakenly in up to 3% of piping components and 10% of items such as drain plugs at some refineries (API, 2009 at 16).
[106] See CSB, 2013 at 16–45; see esp. 33–36. see also API, 2009.
[107] See API, 2009 at 8; CSB, 2013 at 33.
[108] Total acid number (TAN), measured in mg KOH/g oil, reflects organic acids in crude oils that refiners call "naphthenic" acids. "[I]t is important to note that naphthenic acids can dissolve the iron sulfide scale [that might otherwise slow sulfidic corrosion] or at the very least render it less protective. ... [and it] is often difficult to isolate the individual effects of naphthenic acids and sulfur compounds [but] naphthenic acid never lowers sulfidation corrosion." API, 2009 at 4.
[109] CSB, 2013 at 35; API, 2009 at 5, 7, 8 and 16.
[110] TAN ranges from ≈0.9– 1.7 mg KOH/g in tar sands oils that are likely to be refined as a result of the project (see Table 3): 0.5 mg KOH/g is considered high for this acid (see Sheridan, 2006).
[111] County safety staff noted these PHA and ISS requirements (CHMP–Phillips071113); failure to analyze corrosion impacts of crude changes also violates industry standards (CSB, 2013 at 36).

62. Chart 5 shows data describing the scale of emissions from burning more fuel for the extra energy to refine denser, more contaminated crude slates. GHG emissions are plotted against crude slate density. Each white circle represents an annual average observed in one of the four largest U.S. Petroleum Administration Defense districts (PADDs) from 1999–2008; each orange diamond an observed California-wide annual average from 2004–2009; and the black square represents the Shell Martinez refinery annual average observed in 2008. The diagonal rise among the 47 observations from left to right in the chart indicates denser crude slates increase refinery emissions. Observed average emissions nearly double, from ≈260–500 kg/m^3 crude refined, as crude density increases from 860–932 kg/m^3. The SFR crude slate density increment that could result from the project (+37 kg/m^3; paragraphs 12–22) is shown by the width of the yellow band in the chart; the right-hand edge of this band shows the density of the WCS/ANS blend that the refinery could run as a result of the project (952 kg/m^3; see Table 4). This crude slate approaches the density of "heavy oil" as defined by the USGS (957 kg/m^3),[112] and is considerably denser than the Martinez refinery observation (932 kg/m^3), which appears near the middle of the yellow band shown in the chart.

63. Analysis that separated crude quality effects on emissions from those of other factors demonstrated that crude density (shown in Chart 5) and sulfur content (not shown) can explain 85–96% of observed variability in emissions among refining regions and years, allowing the prediction of average emissions from crude slates.[113] Predictions based on the U.S. observations suggest that an industry-wide switch to refining "heavy oil" (shown) and bitumen (not shown) could double or triple current U.S. refining emissions.[114] More recent work using different methods estimates emission increments that are generally consistent with these predictions.[115] Also, the U.S. data and methods used in these predictions were found to predict the observed emissions from the Martinez refinery within ≈7% and the long-term 2004–2009 average California industry emissions within ≈1%.[116] Based on these same data and methods, the project increase in SFR crude

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[112] Heavy oil average density (957 kg/m^3) and sulfur content (2.9 wt. %) from Meyers et al., 2007.
[113] Karras, 2010; UCS, 2011.
[114] Karras, 2010.
[115] See Abella and Bergerson, 2012 (bitumen and dilbit vs. light conventional oils in Figure 1).
[116] UCS, 2011. See pages 9, 12 and 13, and Table 1-1. Four other refinery-specific predictions were tested as well (not shown in chart). When uncertainties caused by the lack of facility products reporting were considered, observed emissions from 4 of the 5 plants were predicted successfully, and emissions were underpredicted in 1 test. These predictions were tested by withholding the California energy and emission observations from the predictive model.

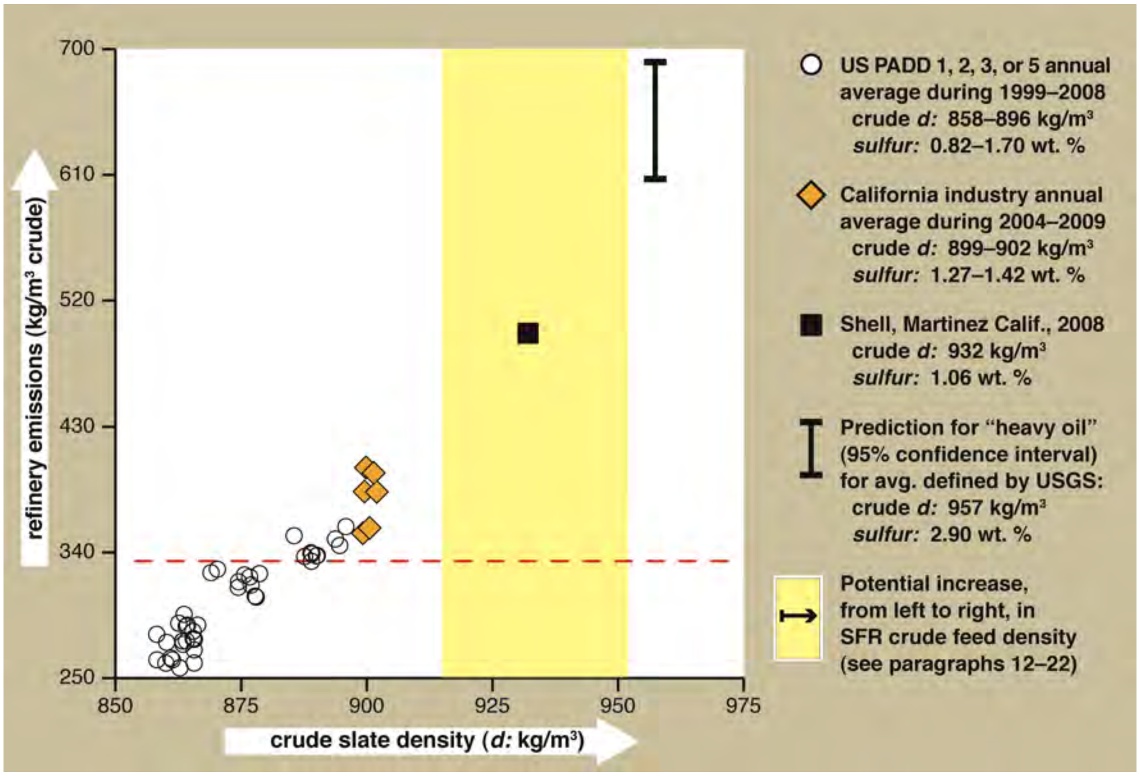

Chart 5. Refinery GHG emission intensity vs. crude feed density. CO_2 emissions increase from ≈260–500 kg per m^3 crude feed as crude density increases from 860–932 kg/m^3. Density (shown) and sulfur (not shown) explain 85–96% of these changes in emissions among refining regions and years. Emissions of ≈610–690 kg/m^3 are predicted from refining the average "heavy oil" (*d,* 957 kg/m^3; *S,* 2.9%). Plant-specific emissions also vary with other properties of oil feeds, products, process configurations and fuels burned, however, the WCS/ANS crude feed shown in Table 4 (*d,* 952 kg/m^3; *S,* 3.4%) is nearly as dense as this heavy oil and denser than a dozen feeds with observed emissions greater than current SFR emissions reported (334 kg/m^3 2009–2011; shown on the vertical scale by the dashed red line). The potential increase in SFR crude feed density (≈915–952 kg/m^3) is shown on the horizontal scale by the width of the yellow band. Each 90 kg/m^3 increment shown on the vertical scale represents emitting 627,000 tonnes/yr at SFR's 120,000 b/d capacity. Data from Karras (2010) and UCS (2011) except SFR emissions (CARB, 2013 for Rodeo and Santa Maria refining and Rodeo Air Liquide H_2 at *Oil & Gas Journal,* 2012 crude capacity).

slate density from 915–952 kg/m^3 and sulfur from 1.5–3.4% could increase the average refinery's energy intensity by ≈2.75 GJ/m^3 crude refined.[117] Assuming the refinery fuels reported in the DEIR,[118] and this average energy increment, SFR emissions of CO_2 would increase by ≈135 kg/m^3, or ≈940,000 tonnes/year. (Each 90 kg/m^3 increment on the vertical scale in Chart 5 represents emission of 627,000 tonnes/yr at SFR's 120,000 b/d capacity.) This ≈940,000 tonnes/yr value indicates the scale of potential impact rather than its precise quantification, as discussed directly below.

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[117] Based on baseline and potential central predictions; confidence of increase > 95%.

[118] Based on fuel mix emission intensity ≈64.23 kg/GJ before and ≈59.45 kg/GJ after project fuel switch, from data in DEIR chapters 4.6 and 4.5; emission factors in UCS (2011) Table 2-1.

64. Plant-specific GHG emissions can vary from industry-average increments with differences in fuels burned, product slates, process configuration, and other properties of oils refined.[119] The DEIR's fuel mix assumption is an example of this variability. The relatively less-dirty current refinery fuel mix it reports[120] appears consistent with SFR's current emission estimate that appears somewhat low in Chart 5 (see dashed red line).[121] However, the DEIR's assumption that *only* natural gas will replace the LPG taken from refinery fuel ignores the potential for burning more petroleum coke in the refinery. See paragraph 46. The 940,000 tonnes/yr figure above could underestimate refinery emissions if any of this LPG is replaced by burning the project's extra coke.

65. Anomalous product slates must be considered, in general, because a refinery that makes much less (or much more) of its crude feed into light liquid fuels,[122] requires less (or more) energy for the severe carbon rejection and hydrogen addition processing needed to make these fuels from crude. This refinery, however, reports light liquid fuels production totaling more than 80% of its feedstock volume,[123] and project LPG would boost its light liquids product ratio still higher. The SFR products slate should be quantified and analyzed based on more data than the DEIR reported, but it is unlikely to decrease refinery GHG emissions relative to the industry average products slate.

66. SFR's process configuration could run the denser and more contaminated crude slate that likely would result from the project (see Table 4), but whether it would use more, or less, energy than the average refinery to do so is a more nuanced question. SFR has no catalytic cracker. Although it has very substantial carbon rejection (coking) capacity, this nevertheless makes it more reliant on severe hydrogen addition (hydro-

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[119] Karras, 2010; Bredeson et al., 2010; UCS, 2011; Abella and Bergerson, 2012.

[120] See DEIR at 4.6-1, 4.6-2.

[121] This current SFR fuel mix emission estimate (≈64.23 kg/GJ; see note 118) is significantly less than the U.S. industry average (≈73.77 kg/GJ; see Karras, 2010 Table S1), but the SFR emissions reported by the company might be underestimated as well. SFR's emission reports received at least one "adverse" verification finding (CARB, 2013) and its Rodeo facility estimate appears slightly lower than that suggested by DEIR fuels data and UCS (2011) emission factors. These reported emissions (2009–2011 avg. including the Air Liquide Rodeo H_2 plant and Santa Maria facility based on CARB, 2013; kg/m^3 crude based on capacity from *Oil & Gas Journal*, 2012) are shown in Chart 5 because this is the emissions report available. Remarkably, the DEIR did not report *any* GHG emission estimate for the SFR refinery or even the Rodeo facility as a whole—a stark example of its failure to analyze this impact.

[122] Light liquid fuels: gasoline; diesel, jet fuel and similar distillates; LPG.

[123] See Phillips, 2012b at Table 1; EIR SCH #2005092028 at Table 3-4; EIR SCH #2002122017 at Table 4.5-2.

cracking, and associated H_2 production), and less reliant on carbon rejection processing, than a refinery with equivalent coking capacity *and* catalytic cracking. Several studies report that refinery configuration can affect energy intensity, emission intensity, or both—but they do not report specific evidence that substituting hydrocracking for catalytic cracking in a coking-based refinery reduces GHG emissions.[124] Instead, they cite hydrogen addition as a key factor increasing refinery energy intensity.[124] Further, the SFR process intensity exceeds reported averages in major U.S. PADDs by 22–78%.[125] Analysis across the U.S. PADDs did find a shift to a slightly less-dirty refinery fuel mix as refiners shifted from catalytic cracking to hydrocracking,[126] but this effect is accounted for already by plant-specific fuels data (see paragraphs 63–64). More detailed data on the SFR process configuration should be gathered and analyzed to better quantify potential emissions.[127] However, beyond the fuel mix (already addressed), there is little evidence that the SFR configuration will uniquely limit emission impacts from a denser and dirtier crude slate, and no evidence that denser crude can be converted to lighter products without energy—and resultant fuel combustion emission—costs.

67. Other properties of crude oils that affect processing may not be predicted reliably by density and sulfur in a poorly mixed crude slate. Many such properties are analyzed and reported (see Crude Assays). This data could have been included in the DEIR. For example, Abella and Bergerson's public domain estimation method calls for distillation, hydrogen content, and carbon residue data along with crude density and sulfur.[127] The project's coking dependence indirectly provides the key part of this distillation data (see paragraphs 14–20). However, hydrogen is a critical energy and emission driver.[124] Tar sands-derived oils tend to be H_2-poor, and refining them has, in some cases, increased energy use and emissions beyond those predicted by density and sulfur.[128] The project's likely use of these oils may emit more than the industry-average prediction suggests.

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[124] See Bredeson et al., 2010; Abella and Bergerson, 2012; Karras, 2010; UCS, 2011.

[125] Process intensity (*PI*): the ratio by volume of vacuum distillation capacity, conversion capacity (catalytic, thermal, and hydrocracking), and crude stream (gas oil and residua) hydrotreating capacity to atmospheric crude distillation capacity. SFR *PI* (1.60) based on data from *Oil & Gas Journal* (2012); U.S. *PI* (0.9–1.31) for PADDs 1, 2, 3, and 5 in 1999-2008 from Karras, 2010.

[126] Karras, 2010.

[127] The County could quantify potential emissions from the crude switch using non-confidential information and readily available analysis tools. Karras (2010) and Abella and Bergerson (2012) each present methods that are designed to be used with publicly verifiable data. Each method appears to have strengths and weaknesses relative to the other, and ideally, both should be used.

[128] See Abella and Bergerson, 2012; Fox, 2013; Karras, 2010.

68. Evidence discussed in paragraphs 62–67 shows that the crude switch likely to result from the project would increase GHG emissions substantially, and could increase them on the order of ≈1,000,000 tonnes/yr, but the actual increment might be half, or twice, that amount, and the DEIR failed to report data that could narrow this uncertainty. If even half (≈500,000 tonnes/yr) or only one-quarter (≈250,000 tonnes/yr) of this emission potential is realized, the emission increment would exceed the 10,000 tonnes/yr threshold of significance for GHG emissions asserted by the DEIR substantially.

69. Emissions of toxic and smog-forming combustion products could increase along with CO_2 as the project crude switch increases refinery energy intensity, requiring the SFR to burn more fuel per barrel of oil processed.[129] Emission of particulate matter air pollution (PM) is of specific concern. Fine particulate matter ($PM_{2.5}$) is associated with ≈14,000–24,000 premature deaths each year statewide, and $PM_{2.5}$ exceeds air quality standards in the project area, as the DEIR acknowledges.[130] Refinery emissions dominate PM exposures locally, and a statewide analysis of PM as a "GHG co-pollutant" found elevated, localized, and disparate health risks associated with refinery PM emissions.[131] The DEIR does not analyze PM emissions from the project crude switch or propose any additional abatement to address them. However, based on the emission factor Phillips reported for 100% natural gas boiler firing,[132] and the energy increment discussed above (≈2.75 GJ/m^3), the project crude switch could increase SFR emissions of $PM_{2.5}$ by an amount much greater than the significance threshold given in the DEIR.[133]

70. Cumulative impacts of the project with other projects that create long-term commitments to future emissions have the potential to result in failure to achieve the cut in emissions that will be necessary before 2050 to avert extreme climate disruption.[134] Indeed, substantial evidence indicates that stabilizing climate at a societally sustainable greenhouse impact level will require leaving approximately half of current fossil energy reserves underground.[134] Among other important implications of this evidence, it argues

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[129] See Karras, 2010; Pastor et al., 2010.
[130] DEIR at 4.3-4, 4.3-5, 4.3-6.
[131] Pastor et al., 2010.
[132] See Air Permit Application at 10, 11 (0.0075 lb $PM_{2.5}$ per MMBtu, which is 3.42 grams/GJ).
[133] Potential emission increment is ≈9.4 g/m^3 crude refined (2.75 GJ/m^3 • 3.42 g/GJ as $PM_{2.5}$) or ≈65.4 tonnes/yr at SFR's 120,000 b/d (6.96 million m^3/yr) capacity. Even one fourth of this increment (≈16 tonnes/yr) exceeds the DEIR's $PM_{2.5}$ significance threshold (10 tons/yr). Other refinery fuel mix scenarios also result in $PM_{2.5}$ estimates exceeding this threshold.
[134] See Davis et al., 2010; Hoffert, 2010; Meinshausen et al., 2009; Allen et al., 2009.

for limiting impacts by choosing to use the least hazardous and least polluting portion of the remaining petroleum resource in the interim.

71. The County could consider a measure that results in using SFR hydrocracking to meet the project's LPG objective without relying on coking a low-quality crude slate. Hydrocracking can be operated to "swing" between product slates, allowing diesel or gasoline or LPG to be its main output, and unlike coking, hydrocracking treats (cleans) its products.[135] Making project LPG from SFR's existing hydrocracking while retaining the project's coker fuel gas hydrotreating is technically feasible and could meet all project objectives stated in the DEIR while avoiding impacts of its potential crude switch. However, increasing LPG output from SFR hydrocracking will limit its gasoline or diesel output,[135] while coker-based LPG production will not—and the proposed project would thereby further boost profits from total light liquids production. In fact, this is one of the reasons the project as proposed would lock the refinery into a denser, more contaminated crude slate. To support this feasible measure, the County could find that boosting profits in a way that makes the project unable to achieve its stated objectives to reduce emissions or to reduce the likelihood of flaring events is not a stated objective of the project.

72. The County also could consider other measures that may lessen impacts from the project's crude switch. However, many different measures may need to be developed to address the myriad potential impacts from refining denser, more contaminated crude. In addition, the relative efficacy of such measures to lessen these impacts cannot, in many cases, be known until the data and analysis that the DEIR could and should have provided to better estimate the scale or severity of these impacts is available for review.

73. On 13 June 2013 the Refinery Action Collaborative, a labor-community collaborative focused on addressing safety and health concerns shared by refinery workers and residents in the Bay Area, submitted to BAAQMD a "recommendation to ensure prevention of feedstock-related emissions increase" that reads in relevant part:

> To prevent new harm from feedstock-related emission increases, each refinery would be required to monitor and report its oil feedstock, and any proposed equipment change related to enabling a change in feedstock quantity or quality. Any proposed change in equipment related to enabling the refining of more oil, lower quality oil, or both, or any actual worsening of oil quality or increase in total oil throughput or both, would trigger a requirement to demonstrate that:

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[135] See Robinson and Dolbear, 2007.

- the change in oil quantity, quality, or both (of the blend, of "slate" of oils refined) will not increase incident emission risk;[††]
- the change in oil quantity, quality, or both will not increase routine emissions of any pollutant; *and*
- the change in oil quantity, quality, or both will not use up any emission reduction measure that is needed to reduce the refinery's ongoing emission of any pollutant that currently causes or contributes to air quality or environmental health harm.

Refiners would bear the burden of making each of these demonstrations. The Air District would bear the burden of ensuring transparent reporting and third-party verification through an independent community/worker oversight board that selects and oversees experts. Refiners would bear the burden of funding this independent verification (the independent oversight board and the experts it selects).

Non reporting consequences: Non reporting must not be allowed to defeat prevention. Equipment changes enabling the refining of more oil, lower quality oil, or both that are not reported before installation (1) cannot be considered in a feasibility analysis as a reason for failure to return to baseline emissions, (2) trigger all required demonstrations retroactively, and (3) require refiner-financed Air District monitoring in place of self-monitoring.

[††] *We anticipate that this would be demonstrated through a Process Hazard Analysis or similar documented, verifiable analysis.*[136]

74. The foregoing recommendation[136] is the first specific blueprint for action to evaluate and prevent environmental health and safety impacts from refining lower quality oil that was developed jointly by refinery worker- and community-based organizations. This jointly-developed proposal could thus be considered a critically important step toward solving this problem as presented by the subject project, as well as many other refinery projects regionally and nationwide. Although the BAAQMD is considering this recommendation in the context of a proposed regional air quality rule that could address emissions from refining lower quality oil specifically, at present no such requirement is in place. Importantly, the recommendation describes in significant detail a comprehensive approach to data reporting, evaluation, catastrophic hazard prevention, and emission impact prevention problems presented by this project's potential crude switch. See paragraphs 12–23, 56–72. The County could consider this recommended approach as it completes its analysis, public review process, and decisions regarding the project.

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[136] Refinery Action Collaborative, June 2013. Members include the Asian Pacific Environmental Network; BlueGreen Alliance; Communities for a Better Environment; Labor Occupational Health Program at U.C. Berkeley; the Natural Resources Defense Council; United Steelworkers International Union; United Steelworkers Local 5, and United Steelworkers Local 326.

Conclusions

75. Catastrophic failure hazard associated with pressurized storage of propane and butane that would be produced and stored without adequate safeguards as a result of the project should be considered a significant potential impact. The DEIR presented an incomplete analysis of this impact, did not identify it as significant, and rejected the consideration required by safety policy of a feasible measure to avoid this impact.

76. Catastrophic failure hazard associated with greater amounts of corrosive, toxic, and flammable materials under high heat and pressure that would be caused by the processing of lower quality oil without adequate safeguards as a result of the project should be considered a significant potential impact. The DEIR did not analyze or identify this impact, and did not consider any measure to lessen or avoid it, although a measure to avoid this impact appears feasible.

77. Acute exposures to air pollutants emitted by flaring to control upsets caused by the processing of lower quality oil resulting from the project should be considered a significant potential impact. The DEIR did not analyze or identify this impact, and did not consider any measure to lessen or avoid it, although a measure that could avoid this impact appears feasible.

78. Acute exposures to air pollutants emitted by flaring associated with feeding fuel gases that have lower heat content to equipment designed to burn fuel gases that have higher heat content as a result of the project *may* be considered a significant potential impact—when data the DEIR did not include are reported and reviewed. The DEIR did not analyze or identify this impact, and did not consider any measure to lessen or avoid it, although such measures are feasible.

79. Exposures to localized air pollution from continuous emissions of fine particulate matter caused by increased fuel combustion associated with the processing of lower quality oil as a result of the project should be considered a significant potential impact. The DEIR did not analyze or identify this impact, and did not consider any measure to lessen or avoid it, although a measure that could avoid this impact appears feasible.

80. Sulfur dioxide (SO_2) emissions could increase, instead of decreasing as the DEIR claims, if “emission reduction credits” resulting from the project are overestimated, and this *may* be considered a significant potential impact—when data the DEIR did not

include are reported and reviewed. The DEIR did not disclose these credits for a future emissions increase that could overwhelm the claimed emissions reduction from another part of the project. It did not analyze that emissions reduction claim against these credits to check on whether the credits are overestimated and could thus result in a net emissions increase. It did not consider any measure to lessen or avoid this potential impact, although a measure that could avoid this impact appears feasible.

81. Destruction of aquatic life and San Francisco Bay-Delta habitat caused by the expansion and continued operation of an outdated once-through cooling system as a result of the project should be considered a significant potential impact. The DEIR did not disclose state efforts that could replace the cooling system—thereby avoiding this impact—or that the project would conflict with and foreclose those efforts. The DEIR presented an incomplete, erroneous, and misleading discussion of this impact, did not identify it as significant, and did not consider any measure to lessen or avoid this impact.

82. Greenhouse gas emissions caused by burning propane and butane that would be produced and sent out of the refinery for this purpose as a result of the project should be considered a significant potential impact. The DEIR presented an erroneous analysis of these emissions, did not identify this impact, and did not consider any measure to lessen or avoid it, although such measures appear feasible.

83. Greenhouse gas emissions caused by increased refinery fuel combustion associated with the processing of lower quality oil resulting from the project should be considered a significant potential impact. The DEIR did not analyze or identify this impact, and did not consider any measure to lessen or avoid it, although a measure that could avoid this impact appears feasible.

84. The June 2013 DEIR did not include the information necessary to understand and evaluate the environmental implications of the project. It did not describe the duration, setting, geographic or processing scope, feedstock, operation, or potential environmental effects of the project accurately or, in many cases, did not describe them at all. These informational deficiencies are so profound, and the revisions needed to cure them so extensive, that full independent review of a comprehensively revised draft would be necessary before public decisions could be based with confidence on this project’s environmental review.

85. I have given my opinions on these matters based on my knowledge, experience and expertise and the data, information and analysis discussed in this report.

I declare under penalty of perjury that the foregoing is true of my own knowledge, except as to those matters stated on information and belief, and as to those matters, I believe them to be true.

Executed this _____ day of September 2013 at Oakland, California

____
Greg Karras

Attachments List

Descriptor	***Attachment***
Abella and Bergerson, 2012	Abella and Bergerson, 2012. Model to investigate energy and greenhouse gas emission implications of refining petroleum: impacts of crude quality and refinery configuration. *Env. Sci. Technol.* DOI: 10.1021/es30186821.
AICE, 1989 (excerpts)	American Institute of Chemical Engineers, Center for Chemical Process Safety, 1989. Guidelines for process equipment reliability data, with data tables. (Excerpts: pp. 183, 205).
Air Permit App.	ERM, 2013. Rodeo Propane Recovery Project BAAQMD Authority to Construct and Significant Revision to Major Facility Review Permit Application, Rodeo Refinery. February 2013.
Air Permit App. Atts 4 and 7	ERM, 2013 (Permit Application). Attachment A-4. Fugitive component TAC emissions; and Attachment A-7. Daily U233 fuel gas data.
Air Permit Correspondence	Correspondence regarding incomplete permit application for the project including: 30 April 2013 letter to Brian Lusher, Bay Area Air Quality Management District, from Don Bristol, Phillips 66 San Francisco Refinery (4/30/13 Phillips letter); 6/28/13 Phillips letter; 3/1/13 Phillips letter; 1 March 2013 letter to Brent Eastep, Phillips 66 Rodeo Refinery, from Brian Lusher, Bay Area Air Quality Management District (3/1/13 BAAQMD letter); 3/21/13 BAAQMD letter; 7/18/13 BAAQMD letter.
Allen et al., 2009	Allen et al., 2009. Warming caused by cumulative carbon emissions towards the trillionth tonne. *Nature* 458: 1163–1166.
API, 2009	American Petroleum Institute, 2009. Guidelines for avoiding sulfidation (sulfidic) corrosion failures in oil refineries. API Recommended Practice 939–C, First Edition.
BAAQMD, 2006	Staff Report, Proposed Amendments to Regulation 12, Miscellaneous Standards of Performance, Rule 12, Flares at Petroleum Refineries. Bay Area Air Quality Management District. 3 March 2006.
BAAQMD, 2009	Bay Area Air Quality Management District 18 September 2009 response to request for facility information by CBE (listing of Chevron Richmond Refinery dates of first operation by equipment source number; includes summary table by CBE).
BAAQMD, 2011	Major Facility Review Permit, Chevron Products Company, Facility #A0010. Bay Area Air Quality Management District. 11

	August 2011.
BAAQMD, 2013	Major Facility Review Permit, Phillips 66–San Francisco Refinery, Facility #A0016. Bay Area Air Quality Management District. 4 March 2013.
Brandt, 2012	Brandt, 2012. Variability and uncertainty in life cycle assessment models for greenhouse gas emissions from Canadian oil sands production. *Env. Sci. Technol.* 46: 1253–1261.
Bredeson et al., 2010	Bredeson et al., 2010. Factors driving refinery CO_2 intensity, with allocation into products. *Int. J. Life Cycle Assess.* 15: 817–826.
CARB, 2013	Mandatory GHG Reporting Data. Emissions reported for calendar years 2009, 2010, 2011. California Air Resources Board. (Dnldd 28 August 2013: https://ghgreport.arb.ca.gov/eats/carb).
CBE, 1994	CBE, 1994. Dirty crude: The first oil industry-wide analysis of selenium discharge trends impacting San Francisco Bay. CBE Report No. 94–1. March 1994.
CBE, 2006	CBE, 2006. Analysis of Potrero Unit 3 entrainment impact evidence. March 2006.
CCHMP–Phillips 071113	Letter to Jim Ferris, Phillips 66 San Francisco Refinery, from Michael Dossey, Contra Costa Health Services Hazardous Materials Program. 11 July 2013.
Chevron R2-2011-0049	NPDES Permit No. CA0005134. Chevron Richmond Refinery. Issued in 2011.
City of Richmond, 2008	Chevron Energy and Hydrogen Renewal Project Final Environmental Impact Report SCH #2005072117 Volume 3–Responses to Comments. January 2008.
Crude Assays	Compilation of publicly reported crude oil assay reports.
CSB, 2005	CSB, 2005. Investigation Report: Refinery Explosion and Fire (15 Killed, 180 Injured); BP Texas City, Texas, March 23, 2005. Report No. 2005–04-I-TX. U.S. Chemical Safety and Hazard Investigation Board. March 2007.
CSB, 2013	CSB, 2005. Interim Investigation Report: Chevron Richmond Refinery Fire; Chevron Richmond Refinery, Richmond, California, August 6, 2012. U.S. Chemical Safety and Hazard Investigation Board. April 2013.
CV and Publications	Curriculum vitae and publications list
Davis et al., 2010	Davis et al., 2009. Future CO_2 emissions and climate change from existing energy infrastructure. *Science* 329: 1330–1333.

DOE COA 2013	DOE, 2013. Crude Oil Analysis Database. U.S. Department of Energy. Data table in Excel. (www.netl.doe.gov/technologies/oil-gas/Software/database.html). Downloaded 8 August 2013.
DOE, 2002.	DOE, 2002. Strategic Petroleum Reserve Crude Oil Assay Manual, 2nd Edition, Revision 2. U.S. Department of Energy. Revised November 2002.
Dolbear AG Summary	Email from Rose Fua, California Deputy Attorney General summarizing and quoting from a review by Dr. Geoff Dolbear regarding the Chevron Richmond refinery (other Bay Area data were reviewed as well). Forwarded to CBE 16 July 2008.
EIA Imports Analysis	Tables of data for foreign oils processed by the San Francisco Refinery reported by the U.S. Energy Information Administration (www.eia.gov/petroleum/imports/comanylevel/archive)
EIA Ref. Cap. 2013	U.S. Energy Information Administration, 2013. Refinery Capacity Data by Individual Refinery as of January 1, 2013 (www.eia.gov/petroleum/data). Downloaded 26 August 2013.
EIA Refinery Yield	U.S. Energy Information Administration, 2013. U.S. Refinery Yield. (www.eia.gov/dnav/pet/pet_pnp_pct_dc_nus_pct_m.htm)
ERCB st98–2009	ERCB, 2009. Alberta's Energy Reserves 2008 and Supply/Demand Outlook 2009–2018. Report ST98–2009. Energy Resources Conservation Board, Alberta, Canada. June 2009.
ERM & BAAQMD, 2012	CEQA Initial Study: Marine Terminal Offload Limit Revision Project, Phillips 66 Refinery, Rodeo, California, BAAQMD Permit Application 22904. Bay Area Air Quality Management District (prepared by ERM). December 2012.
Flare Causal Analysis excerpts	Phillips 66, various dates. Determination and Reporting of Cause reports pursuant to BAAQMD Rule 12-12 §406 for flaring initiating on 3/16/12, 4/25/12, 5/23/12, 5/31/12, 8/27/12.
Flaring Hot Spots	Karras and Hernandez, 2005. Flaring hot spots: Assessment of episodic air pollution associated with oil refinery flaring using sulfur as a tracer. A CBE Report. July 2005.
Flaring Prevention Measures	Karras et al., 2007. Flaring Prevention Measures. A CBE Report. April 2007.
Fox, 2013	Fox, 2013. Comments on Initial Study/Mitigated Negative Declaration for the Valero Crude by Rail Project, Benicia, California, Use Permit Application 12PLN–00063. July 2013.
Goodman, 2013	Goodman and Rowan, 2013. Comments of the Goodman Group, Ltd., on Initial Study/Mitigated Negative Declaration, Valero

	Crude by Rail Project, Benicia, California, Use Permit Application 12PLN-00063.
Hoffert, 2010	Hoffert, 2009. Farewell to fossil fuels? *Science* 329: 1292–1294.
Karras, 2008	Karras, 2008. Chevron Renewal Project, SCH #2005072117, City #1101974 Agenda Report, Consolidated EIR and Staff-recommended EIR and Conditional Use conditions and findings related to oil quality cap; expert report.
Karras, 2010	Karras, 2010. Combustion emissions from refining lower quality oil: What is the global warming potential? *Env. Sci. Technol.* 44(24): 9584–9589.
Karras, 2013	Testimony of Greg Karras, Senior Scientist, CBE, before the U.S. Chemical Safety and Hazard Investigation Board (CSB), 19 April 2013, Memorial Auditorium, Richmond, CA.
LOHP, 2013	Wilson, 2013. Refinery Safety in California: Labor, community and fire agency views. Summary report prepared for the Office of Governor Jerry Brown, Interagency Task Force on Refinery Safety, by the Labor Occupational Health Program at U.C. Berkeley. Revised 4 June 2013.
Meinshausen et al., 2009	Greenhouse-gas emission targets for limiting global warming to 2 ºC. *Nature* 458: 1158–1162.
Meyer et al., 2007	Meyer, 2007. Heavy oil and natural bitumen resources in geological basins of the world: U.S. Geological Survey Open-File Report 2007-1084.
Meyers, 1986	Handbook of petroleum refining processes. Meyers, Robert A., ed. ISBN 0-07-041763-6. McGraw-Hill. 1986.
NPDES Permit R2-1985-029	NPDES Permit No. CA0005053. Union Oil Co. San Francisco Refinery, Rodeo. Issued in 1985.
NPDES Permit R2-1989-002	NPDES Permit No. CA0005053. Union Oil Co. San Francisco Refinery, Rodeo. Issued in 1989.
NPDES Permit R2-2000-015	NPDES Permit No. CA0005053. Tosco Corp. San Francisco Refinery at Rodeo. Issued in 2000.
NPDES Permit R2-2005-0030	NPDES Permit No. CA0005053. ConocoPhillips Corp. San Francisco Refinery at Rodeo. Issued 2005.
NPDES Permit R2-2011-0027	NPDES Permit No. CA0005053. ConocoPhillips Corp. San Francisco Refinery at Rodeo. Issued in 2011.
NPDES Permit R3-2007-0002	NPDES Permit No. CA0000051. ConocoPhillips Corp. Santa Maria Refinery. Issued in 2007.

Oil & Gas Journal, 2012	Koottungal, 2012. 2012 Worldwide Refining Survey. *Oil & Gas Journal.* 3 December 2012 (All figures are as of January 1, 2013).
Pastor et al., 2010	Pastor et al., 2020. *Minding the climate gap: What's at stake if California's climate law isn't done right and right away.* USC Program for Environmental and Regional Equity: Los Angeles, CA. http://college.usc.edu/pere/publications.
Phillips Cooling Tower	*Cooling Tower Replacement Feasibility Evaluation, Order R2-2011-0027; Provision VI.C.2.f., Phillips 66 San Francisco Refinery at Rodeo.* Submitted by Don Bristol, Superintendent, Environmental Services, Phillips 66 San Francisco Refinery, no 30 September 2013. (13-page report)
Phillips Intake Rpt.	*Waste Water Annual Report for 2012, Phillips 66, San Francisco Refinery.*
Phillips Thermal ext. 1	8 August 2012 letter from Don Bristol, Phillips 66 San Francisco Refinery, to Regional Water Quality Control Board, San Francisco Bay Region, regarding: *Phase 2 Thermal Plume Study Final Report, NPDES Order #R2-2011-0027, Provision VIC2d; Task 3 Request for Due Date Extension.*
Phillips Thermal ext. 2	4 September 2012 letter from Bruce Wolfe, Regional Water Quality Control Board, San Francisco Bay Region, to Don Bristol, Phillips 66 San Francisco Refinery, regarding: *Phase 2 Thermal Plume Study Final Report Compliance Date Extension.*
Phillips, 2012a	Phillips 66, 2012. *Propane Recovery Project Overview, August 13 2012, Phillips 66 San Francisco Refinery.* Submitted to BAAQMD. Provided by BAAQMD to CBE (slides presentation).
Phillips, 2012b	Phillips 66, 2012. *Rodeo Propane Recovery Project, Project Description.* August 2012. Submitted to BAAQMD. Provided by BAAQMD to CBE (32-page document).
Refinery Action Collaborative, June 2013	Letter to Jack Broadbent, Bay Area Air Quality Management District, from the Refinery Action Collaborative regarding: *Bay Area Air Quality Management District Proposed Regulation 12, Rule 15; March 2013 Preliminary Draft Petroleum Refining Emissions Tracking Rule.* 13 June 2013.
Regional Monitoring Program	Regional Monitoring Program (RMP) Results. San Francisco Estuary Institute. Data tables report generated by the RMP Web Query (www.sfei.org/mp/mp_data_access.html). Report generated 17 August 2013.
Robinson and Dolbear, 2007	Robinson and Dolbear, 2007. Commercial hydrotreating and hydrocracking. In *Hydroprocessing of heavy oils and residua;*

	Ancheyta, J., Speight, J.G., Eds.; CRC Press, Taylor & Francis Group: Boca Raton, FL. Vol. 117: 281-311.
Shell R2-2012-0052	NPDES Permit No. CA0005789. Shell Martinez Refinery. Issued in 2012.
Sheridan, 2006.	*California Crude Oil Production and Imports.* Staff Paper. CEC-600-2006-006. Margaret Sheridan, Fossil Fuels Office, California Energy Commission. April 2006.
SMF EIR 2012 Excerpts.	*Phillip 66 Santa Maria Refinery Throughput Increase Project Final Environmental Impact Report.* SCH #20081010111. Prepared for San Luis Obispo County Department of Building and Planning by Marine Research Specialists (MRS). October 2012. Excerpt includes cover page, table of contents, and project description (chapter 2.0).
Speight, 1991	Speight, 1991. *The chemistry and technology of petroleum,* 2nd ed.; Heinemann, H., Ed.; Marcel Dekker: New York, Chemical Industries, Vol. *44.*
State Lands, 1995.	*Final Environmental Impact Report for Consideration of a New Lease for the Operation of a Crude Oil and Petroleum Product Marine Terminal on State Tide and Submerged Lands at Unocal's San Francisco Refinery, Oleum, Contra Costa County.* SCH # 91053082. Prepared for State Lands Commission by Chambers Group, Inc. February 1995.
Subra, 2008	*Chevron Energy and Hydrogen Renewal Project.* Expert report prepared for the Asian Pacific Environmental Network by Wilma Subra, Subra Company, New Iberia, LA. May 2008.
SWRCB, 2010	*Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling.* California State Water Resources Control Board. October 2010.
Tesoro R2-2010-0084	NPDES Permit No. CA0004961. Tesoro Golden Eagle Refinery. Issued in 2010.
UCS, 2011	UCS, 2011. *Oil Refinery CO_2 Performance Measurement.* Union of Concerned Scientists: Berkeley, CA. Technical analysis prepared for UCS by G. Karras, Communities for a Better Environment. September 2011.
Valero R2-2009-0079	NPDES Permit No. CA0005550. Valero Benicia Refinery. Issued in 2009.
Wilhelm et al., 2007	Wilhelm et al., 2007. Mercury in crude oil processed in the United States (2004). *Env. Sci. Technol.* 41(13): 4509–4514.

Exhibit I

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U.S. CHEMICAL SAFETY AND HAZARD INVESTIGATION BOARD

INTERIM INVESTIGATION REPORT

CHEVRON RICHMOND REFINERY FIRE

CHEVRON RICHMOND REFINERY

RICHMOND, CALIFORNIA

AUGUST 6, 2012

KEY ISSUES

- INHERENTLY SAFER DESIGN
- DAMAGE MECHANISM HAZARD REVIEW
- EFFECTIVE ANALYSIS OF PROCESS SAFEGUARDS IN PROCESS HAZARD ANALYSIS

Summary

On August 6, 2012, the Chevron U.S.A. Inc. Refinery in Richmond, California, experienced a catastrophic pipe failure in the #4 Crude Unit. The pipe ruptured, releasing flammable, hydrocarbon process fluid which partially vaporized into a large vapor cloud that engulfed nineteen Chevron employees. All of the employees escaped, narrowly avoiding serious injury. The flammable portion of the vapor cloud ignited just over two minutes after the pipe ruptured. The ignition and subsequent continued burning of the hydrocarbon process fluid resulted in a large plume of unknown and unquantified particulates and vapor traveling across the Richmond, California, area. In the weeks following the incident, approximately 15,000 people from the surrounding area sought medical treatment due to the release. Testing commissioned by the U.S. Chemical Safety and Hazard Investigation Board (CSB) and the California Division of Occupational Safety and Health (Cal/OSHA) determined that the pipe failed due to thinning caused by sulfidation corrosion, a common damage mechanism in refineries. As a result of the incident, the Chevron Richmond Refinery crude unit remains out of commission over eight months later. In addition, Cal/OSHA issued the refinery 17 citations related to the incident and eight additional citations, with a total proposed fine of nearly one million dollars. In this interim report, the CSB is issuing recommendations to Chevron, the City of Richmond, Contra Costa County, Cal/OSHA, the State of California, and the U.S. Environmental Protection Agency, addressing the need for inherently safer design, rigorous and documented damage mechanism hazard reviews, and thorough analyses of process safeguards.

This interim investigation report contains detailed analyses of and makes recommendations to Chevron and regulatory bodies at the local, state, and federal level. The CSB believes the findings and recommendations presented in this report can be applied to refineries, chemical plants, and other industries nationwide to improve process safety.

The CSB plans to release a comprehensive Final Investigation Report later in 2013 that will include analyses and recommendations relating to technical and regulatory investigation findings which are not included in this interim report. The Final Investigation Report will cover topics including: the importance of having a competent, well-funded regulator and an adaptable regulatory regime; Chevron safety culture; process safety indicator data collection and reporting; emergency planning and response; stop work authority; and recommendations for improvement of petroleum industry standards and recommended practices. Some of these issues are previewed at the end of this interim report under *Additional Issues Currently Under Investigation*.

Table of Contents

Figures

Acronyms and Abbreviations

ALARP	As Low As Reasonably Practicable
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
BIN	Business Improvement Network
bpd	Barrels Per Day
BPTC	BP Texas City
CAA	Clean Air Act
Cal/OSHA	California Division of Occupational Safety and Health
CCPS	Center for Chemical Process Safety
CCR	California Code of Regulations
Chevron ETC	Chevron Energy Technology Company
CML	Condition Monitoring Locations
CSB	U.S. Chemical Safety and Hazard Investigation Board
CSHO	Compliance Safety and Health Officer
CWS	Community Warning System
EPA	Environmental Protection Agency
°F	degree Fahrenheit
HSE	Health and Safety Executive
ISO	Industrial Safety Ordinance
ISS	Inherently Safer Systems
IST	Inherently Safer Technology
KPI	Key Process Indicator

LEPC	Local Emergency Planning Committee
LOPA	Layers of Protection Analysis
MOC	Management of Change
NEP	National Emphasis Program
OEM	U.S. EPA Office of Emergency Management
OSHA	Occupational Safety and Health Administration
P&P	Policy and Procedures
PHA	Process Hazard Analysis
PMI	Positive Materials Identification
psig	Pounds Per Square Inch Gauge
PSM	Process Safety Management
RISO	City of Richmond Industrial Safety Ordinance
RLOP	Richmond Lube Oil Project
RMP	Risk Management Plan
SIP	Shelter-In-Place
TML	Thickness Monitoring Location
UK	United Kingdom
USW	United Steelworker International Union
wt. %	Weight Percent

Background and Findings

1. On August 6, 2012, the Chevron U.S.A. Inc. Refinery in Richmond, California (Chevron Richmond Refinery), experienced a catastrophic pipe rupture in the #4 Crude Unit (crude unit). The ruptured pipe released a flammable hydrocarbon process fluid which then partially vaporized into a large vapor cloud that engulfed nineteen Chevron U.S.A. Inc. (Chevron) employees. At 6:33 pm, approximately two minutes after the release, the flammable portion of the vapor cloud ignited.[i] Eighteen of the employees safely escaped from the cloud just before ignition; one employee, a firefighter, was inside a fire engine that caught fire when the vapor cloud ignited (Figure 1). Because he was wearing full body fire-fighting protective equipment, he was able to make his way to safety. Six Chevron employees suffered minor injuries during the incident and subsequent emergency response efforts.

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[i] Surveillance footage provided by Chevron. Chevron clarified to CSB that video time is approximately 5 minutes out of sync. The video can be found at http://www.csb.gov/videoroom/detail.aspx?VID=69 (accessed February 8, 2013).

Figure 1. The burned remains of the fire truck that was consumed by the fire. A firefighter was in the cab when the vapor cloud ignited. The fire truck was positioned approximately 65 feet from the leak location.

2. The ignition and subsequent continued burning of the hydrocarbon process fluid resulted in a large plume of unknown and unquantified particulates and vapor traveling across the Richmond, California, area (Figures 2 and 3). This resulted in a Community Warning System (CWS) Level 3 alert,[i] and a shelter-in-place[ii] (SIP) was issued at 6:38 pm[1] for the cities of Richmond, San Pablo, and North Richmond. It was lifted later that night at 11:12 pm after the fire was fully under control. In the weeks following the incident, nearby medical facilities received over 15,000 members of the public seeking treatment for ailments including breathing problems, chest pain, shortness of breath, sore throat, and headaches. Approximately 20 people were admitted to local hospitals as inpatients for treatment.

Figure 2. Vapor cloud (white) over Richmond area and smoke (black) from Chevron Richmond Refinery fire as seen from San Rafael in Marin County.[2]

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[i] A Community Warning System Level 3 alert indicates that a facility within Contra Costa County has had a release that has offsite impact and is categorized by any of the following:

1. Off-site impact that may cause eye, skin, nose and/or respiratory irritation to the general population.
2. Fire, explosion, heat, or smoke with an off-site impact. Example: On a process unit/storage tank where mutual aid is requested to mitigate the event and the fire will last longer than 15 minutes.
3. Hazardous material or fire incident where the incident commander or unified command, through consultation with the Contra Costa Health Services Hazardous Material Incident Response Team, requests that sirens should be sounded.

See http://cchealth.org/hazmat/pdf/incident_notification_policy.pdf (accessed April 9, 2013).

[ii] Contra Costa County considers a shelter-in-place to include going inside a home or nearest building, closing doors and windows, and turning off heating, ventilation, and air conditioning. *See* http://cchealth.org/emergencies/shelter-in-place.php (accessed February 6, 2013).

Figure 3. Initial vapor cloud formation (white cloud) and subsequent ignition (black smoke) as seen from a pier in San Francisco, California.

3. The incident occurred from the piping referred to as the “4-sidecut” stream, one of several process streams exiting the C-1100 Crude Unit Atmospheric Column (Figure 4).[i] A plot plan of the crude unit shows the leak location relative to C-1100 (Figure 5). As shown in Figure 6, light gas oil (the crude unit 4-sidecut process fluid) exits the atmospheric column via a 20-inch nozzle and is split into a 12-inch line and an 8-inch line. The August 6, 2012, pipe rupture (Figure 7) occurred on a 52-inch long component[ii] of the 4-sidecut 8-inch line (the 52-inch component). The line operated at a temperature of 640 degrees Fahrenheit (°F)[iii] and had an operating pressure of approximately 55 pounds per square inch gauge (psig) at the rupture location. At the

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[i] The atmospheric column separates crude oil feed into different streams through distillation. These streams are further processed in other units in the refinery.

[ii] The term “component” refers to a portion of piping between welds or flanges. It includes straight run piping and pipe fittings.

[iii] The auto-ignition temperature for this process, the temperature at which a material will combust in the presence of sufficient oxygen without an ignition source, was also 640 °F. This number is based on the Chevron Light Gas Oil Material Safety Data Sheet. Chemical testing of 4-sidecut samples following the incident indicated lower auto-ignition temperatures; however, these samples may not have been representative of typical 4-sidecut process fluid.

time of the incident, light gas oil was flowing through the 8-inch line at a rate of approximately 10,800 barrels per day (bpd).[i]

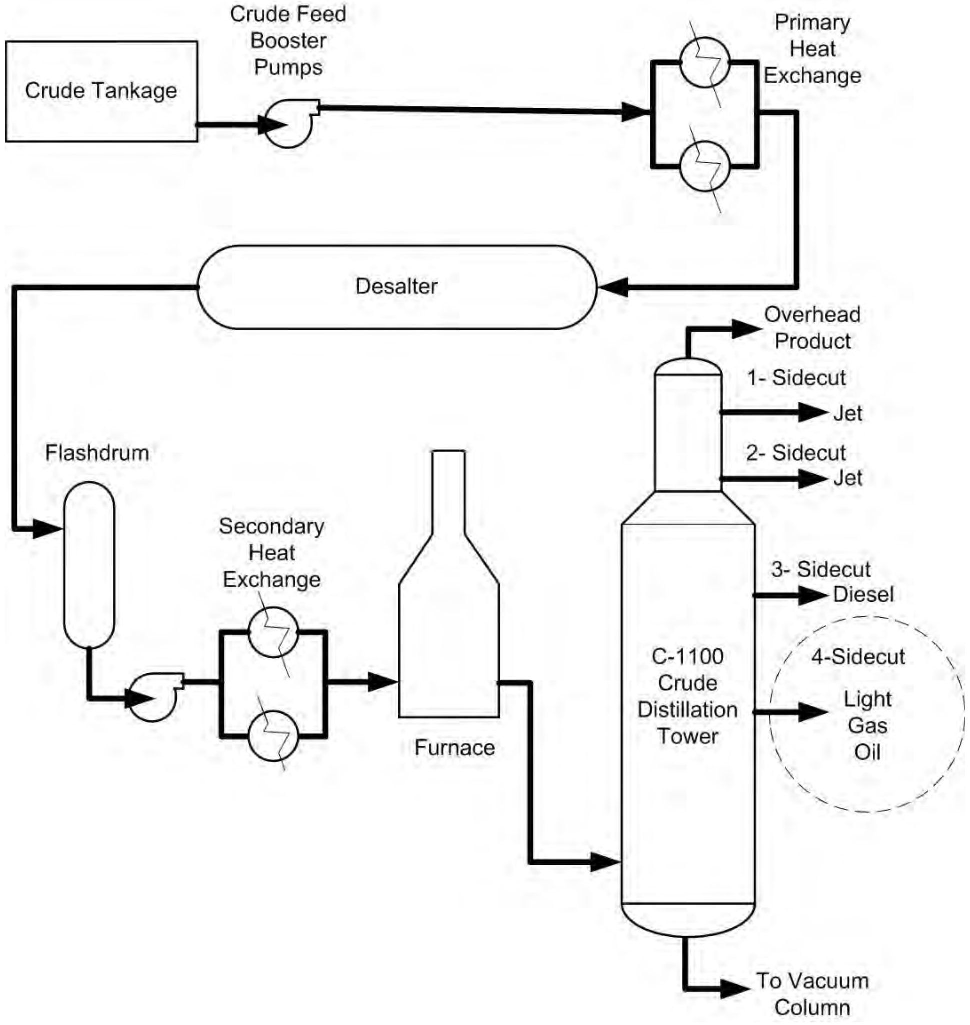

Figure 4. C-1100 Crude Unit Atmospheric Column and Upstream Process Equipment.

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[i] This is the equivalent of 315 gallons per minute (gpm). A barrel equals 42 gallons.

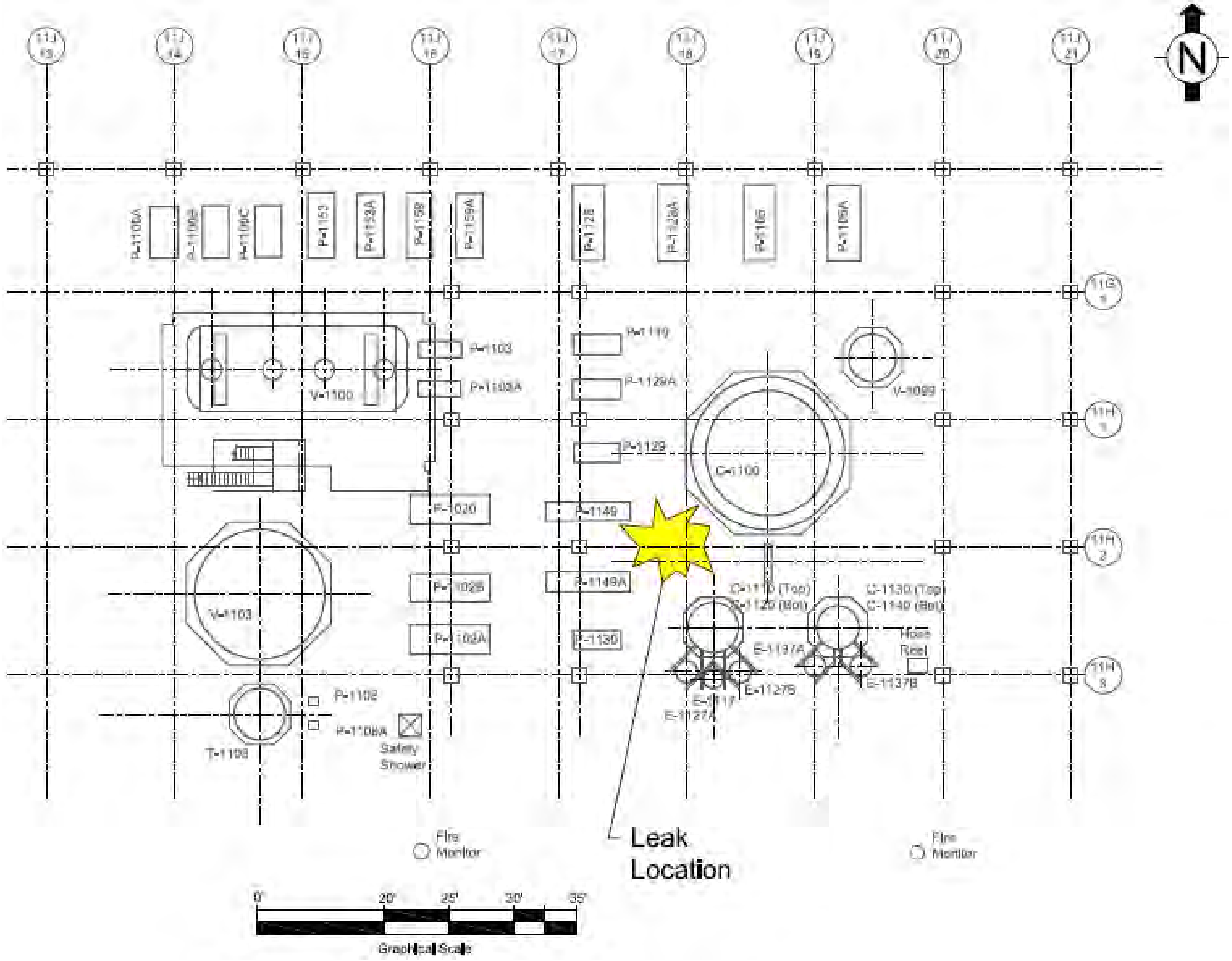

Figure 5. Overhead view of the equipment in the #4 Crude Unit showing the leak location, commonly referred to as a plot plan.

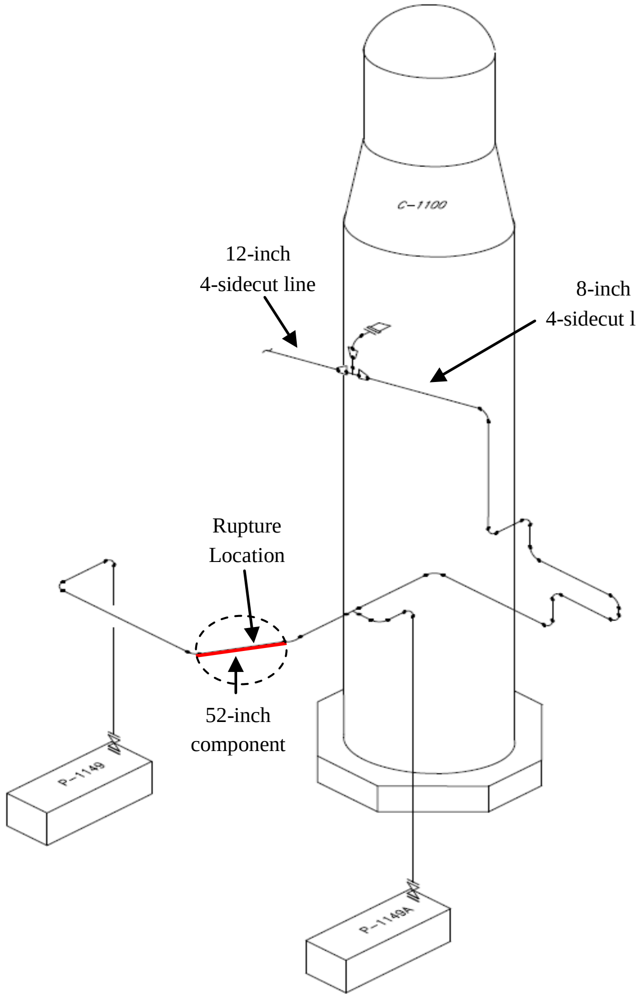

Figure 6. 4-sidecut line configuration and rupture location.

4. The CSB commissioned Anamet, Inc., a materials engineering and laboratory testing company, to conduct testing of the 4-sidecut pipe, including the failed 52-inch component. The testing concluded that the rupture was due to pipe wall thinning caused by sulfidation corrosion,[3] which is discussed below.

5. Anamet's metallurgical analysis found that the 52-inch component where the rupture occurred had experienced extreme thinning; the average wall thickness near the rupture location was approximately 40 percent thinner than a dime[i] (the thinnest American coin). Between 1976 and 2012, the 52-inch piping component had lost, on average, 90 percent of its original wall thickness in the area near the rupture. The piping had an initial nominal wall thickness of 0.322-inch[ii] when it was installed in 1976.

Figure 7. Photo of rupture on 4-sidecut 52-inch component.

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[i] The U.S. Mint reports that a dime has a thickness of 1.35 mm, or 0.053 inches. Information can be found at http://www.usmint.gov/about_the_mint/?action=coin_specifications (accessed February 14, 2013).

[ii] This portion of the 4-sidecut line was constructed of 8-inch Schedule 40 carbon steel piping.

Sulfidation Corrosion

6. Sulfidation corrosion is a damage mechanism[i] that is well understood in the refining industry. The sulfidation corrosion industry guidance document, American Petroleum Institute (API) Recommended Practice (RP) 939-C *Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries*[ii] notes:

> [Sulfidation] …is not a new phenomenon, but was first observed in the late 1800s in a pipe still (crude separation) unit, due to the naturally occurring sulfur compounds found in crude oil. When heated for separation, the various fractions in the crude were found to contain sulfur compounds that corroded the steel equipment.[4]

7. Sulfidation corrosion, also known as sulfidic corrosion,[5] is a damage mechanism that causes thinning in iron-containing materials, such as steel, due to the reaction between sulfur compounds and iron at temperatures ranging from 450 °F to 800 °F.[6] This damage mechanism causes pipe walls to gradually thin over time. Sulfidation corrosion is common in crude oil distillation[iii] where naturally occurring sulfur and sulfur compounds found in crude oil feed, such as hydrogen sulfide,[iv] are available to react with steel piping and equipment. Process variables that affect corrosion rates include the total sulfur content of the oil, the sulfur species present, flow conditions, and the temperature of the system. Virtually all crude oil feeds contain sulfur compounds and, as a result, sulfidation corrosion is a damage mechanism present at every refinery that processes crude oil. Sulfidation corrosion can cause thinning to the point of pipe failure when not properly monitored and controlled.

8. The reaction between sulfur and iron produces a layer of iron sulfide scale[v] on the inside surface of piping.[7] This reaction can be compared to that of oxygen and iron which also produces a scale, commonly known as rust. The type of scale formed by sulfidation corrosion is dependent upon the components contained in the steel. Certain scales formed are protective and actually reduce the reaction rate between sulfur compounds and iron, minimizing sulfidation corrosion

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[i] Piping damage mechanisms are any type of deterioration encountered in the refining and chemical process industry that can result in flaws/defects that can affect the integrity of piping (e.g. corrosion, cracking, erosion, dents, and other mechanical, physical or chemical impacts). *See* API 570. "Piping Inspection Code: In-Service Inspection, Rating, Repair, and Alteration of Piping Systems." 3rd ed., Section 3.1.1.5, November 2009.

[ii] API RP 939-C is one of several relevant American Petroleum Institute recommended practices and standards under evaluation by the CSB as part of this investigation. To the casual observer API RP 939-C appears to obligate the industry to take significant actions. However, the CSB concluded it was written to be permissive so that industry compliance with specific provisions would not be required. The complete findings from this evaluation will be included in the CSB's Final Report.

[iii] Distillation separates mixtures into broad categories of its components by heating the mixture in a distillation column where different products boil off and are recovered at different temperatures. *See* http://www.eia.gov/todayinenergy/detail.cfm?id=6970 (accessed April 4, 2013).

[iv] Hydrogen sulfide is the most aggressive sulfur compound that causes sulfidation corrosion.

[v] Scale is a nonmetallic layer on the surface of metals and is often a result of corrosion.

rates. For instance, sulfidation corrosion affecting steel alloys containing greater than two weight percent (wt. %) chromium produces a protective scale that inhibits the reaction between the iron and sulfur compounds, thereby reducing corrosion rates.[i] With increasing percentages of chromium, the reaction is further slowed, greatly diminishing corrosion rates.[8,ii] For example, stainless steel (an 18 wt. % chromium alloy) is nearly 15 times more resistant to sulfidation corrosion than 9-Chrome (a 9 wt. % chromium alloy).[9] Conversely, sulfidation corrosion rates are significantly higher in steels containing very little chromium. Carbon steel, the Chevron 4-sidecut line material of construction, was manufactured with a maximum concentration of 0.40 % chromium.[10] The scale formed on carbon steel is less protective and allows continued reaction between the sulfur compounds and iron.[11] Thus, carbon steel corrodes at a rate that is significantly faster than other materials of construction, such as high chromium steels.

9. In addition to its inherently faster rate of sulfidation corrosion when compared with higher chromium steels, carbon steel also experiences significant variation in corrosion rates due to variances in silicon content, a component used in the steel manufacturing process. Carbon steel piping containing silicon content less than 0.10 wt. % can corrode at accelerated rates,[12] up to sixteen times faster than carbon steel piping containing higher percentages of silicon as shown in Figure 8. This figure shows how carbon steel corrosion rates can greatly vary depending on silicon content.

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[i] At greater than two wt. % chromium, sulfur compounds react with the steel to form $FeCr_2S_4$ scale. This scale provides more protection than the FeS scale that forms on carbon steel piping. *See* Niccolls, E. H., J. M. Stankiewicz, J. E. McLaughlin, and K. Yamamoto. "High Temperature Sulfidation Corrosion in Refining." *17th International Corrosion Congress.* Las Vegas: NACE International, 2008.

[ii] It has also been found that chromium “poisons” the decomposition of sulfur compounds to hydrogen sulfide which also slows down the sulfidation corrosion rate. *See* Couper, A.S. “High Temperature Mercaptan Corrosion of Steels.” *19th Annual Conference of the National Association of Corrosion Engineers*. Pages 396t-401t, New York: March 1963.

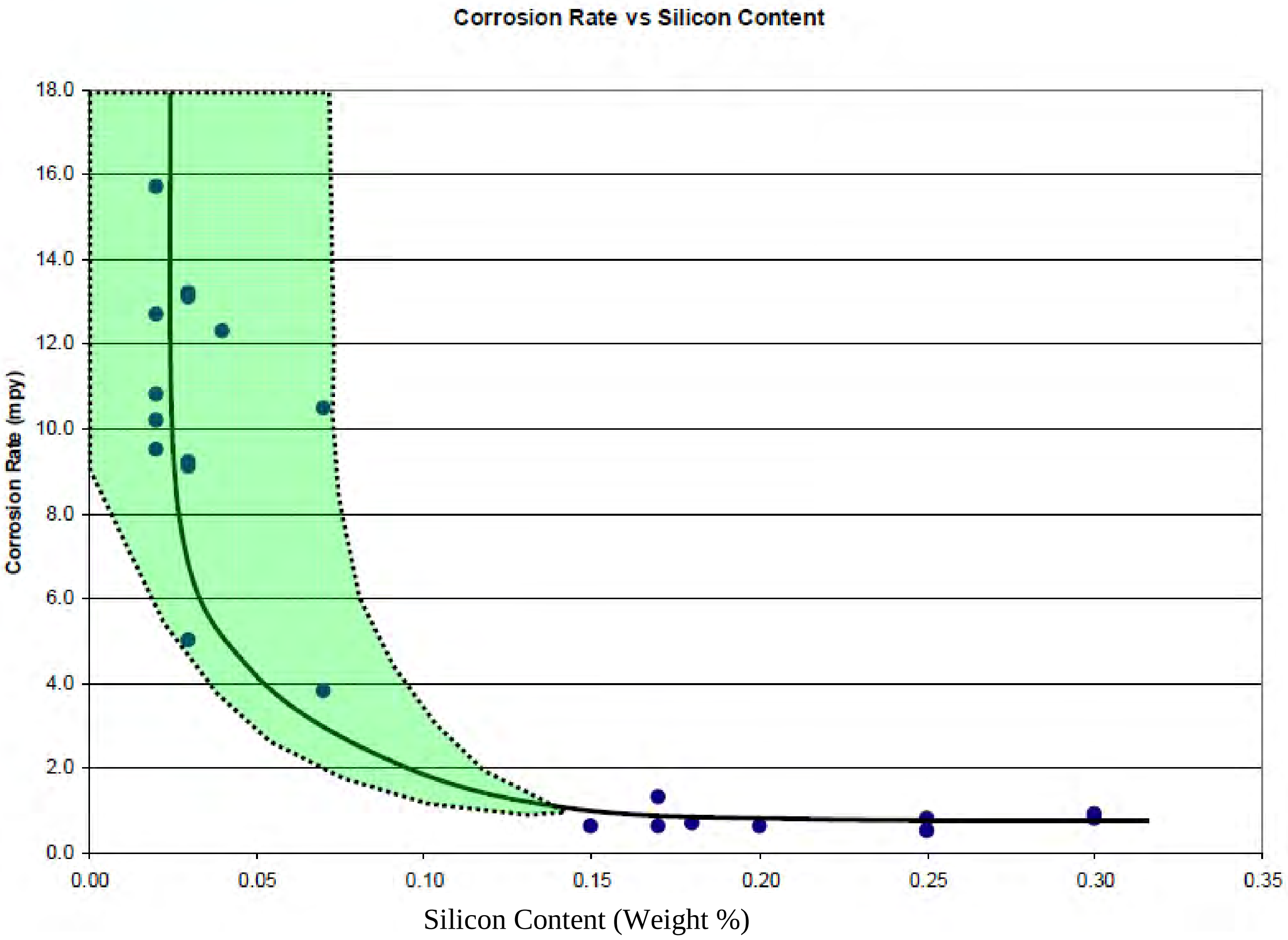

Figure 8. This graph shows how corrosion rates increase in carbon steel containing decreasing percentages of silicon. This information can be found in Annex C of API RP 939-C.[i]

10. The refining industry has been aware of increased rates of sulfidation corrosion in low-silicon carbon steel piping since as early as 1974,[13] nearly 40 years before the August 6, 2012, incident and two years before the Chevron crude unit was constructed. Prior to the incident, Chevron documented its understanding of the significant consequences of sulfidation corrosion. This is reflected in Chevron's *Corrosion Prevention and Metallurgy Manual*, which states:

> Sulfidation corrosion has caused severe fires and fatalities in the refining industry, primarily because it causes corrosion over a relatively large area, so failures tend to involve ruptures or large leaks rather than pinhole leaks. It can be insidious in that moderately high corrosion rates can go undetected for years before failure. Finally, process changes that increase the temperature or sulfur content can creep up over time and

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[i] The y-axis of this figure is in units of mils per year (mpy). A "mil" is 1/1000 inch.

multiply corrosion rates so that what was thought to be a low corrosion rate system becomes corrosive enough to fail before the increased corrosion rate is recognized.

11. Carbon steel piping is manufactured to meet certain specifications, including American Society for Testing and Materials (ASTM) A53B,[14] ASTM A106,[15] and API 5L.[16] ASTM A53B and API 5L do not contain minimum silicon content requirements for carbon steel piping,[17] while ASTM A106 requires the piping to be manufactured with a minimum silicon content of 0.10 wt. %. As a result, manufacturers have used different levels of silicon in the carbon steel pipe manufacturing process. Thus, depending on the manufacturing specification for carbon steel susceptible to sulfidation corrosion, corrosion rates could vary depending on the silicon content within the steel.

12. In the mid 1980s, pipe manufacturers began to simultaneously comply with all three manufacturing specifications (ASTM A53B, ASTM A106, and API 5L) when manufacturing carbon steel piping. The majority of carbon steel piping purchased following this time period likely has a minimum of 0.10 wt. % silicon content. However, piping purchased and installed prior to the mid-1980s could still contain low silicon components that are susceptible to high, variable sulfidation corrosion rates.

13. Over 95 percent of the 144 refineries in operation in the U.S., including the Chevron Richmond Refinery,[i] were built before 1985,[18] and thus before piping manufacturers began producing carbon steel in compliance with all three manufacturing specifications. Therefore, the original carbon steel piping in these refineries is likely to contain varying percentages of silicon content and may experience highly variable sulfidation corrosion rates.

14. The Chevron Richmond Refinery 4-sidecut piping circuit containing the 52-inch component that failed was constructed of ASTM A53B carbon steel, which had no minimum specification for silicon content. Post-incident testing of samples of the 4-sidecut piping from the Chevron Richmond Refinery identified silicon content ranging from 0.01 wt. % to 0.2 wt. %. Of twelve samples taken from the 8-inch and 12-inch 4-sidecut line, six had a silicon concentration of less than 0.10 wt. %. The 52-inch pipe component that ruptured on the day of the incident had a silicon content of only 0.01 wt. %. The elbow component directly upstream of the 52-inch component that failed had a silicon concentration of 0.16 wt. % and showed considerably less thinning (Figure 9).

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[i] The Chevron Richmond Refinery was constructed in 1902.

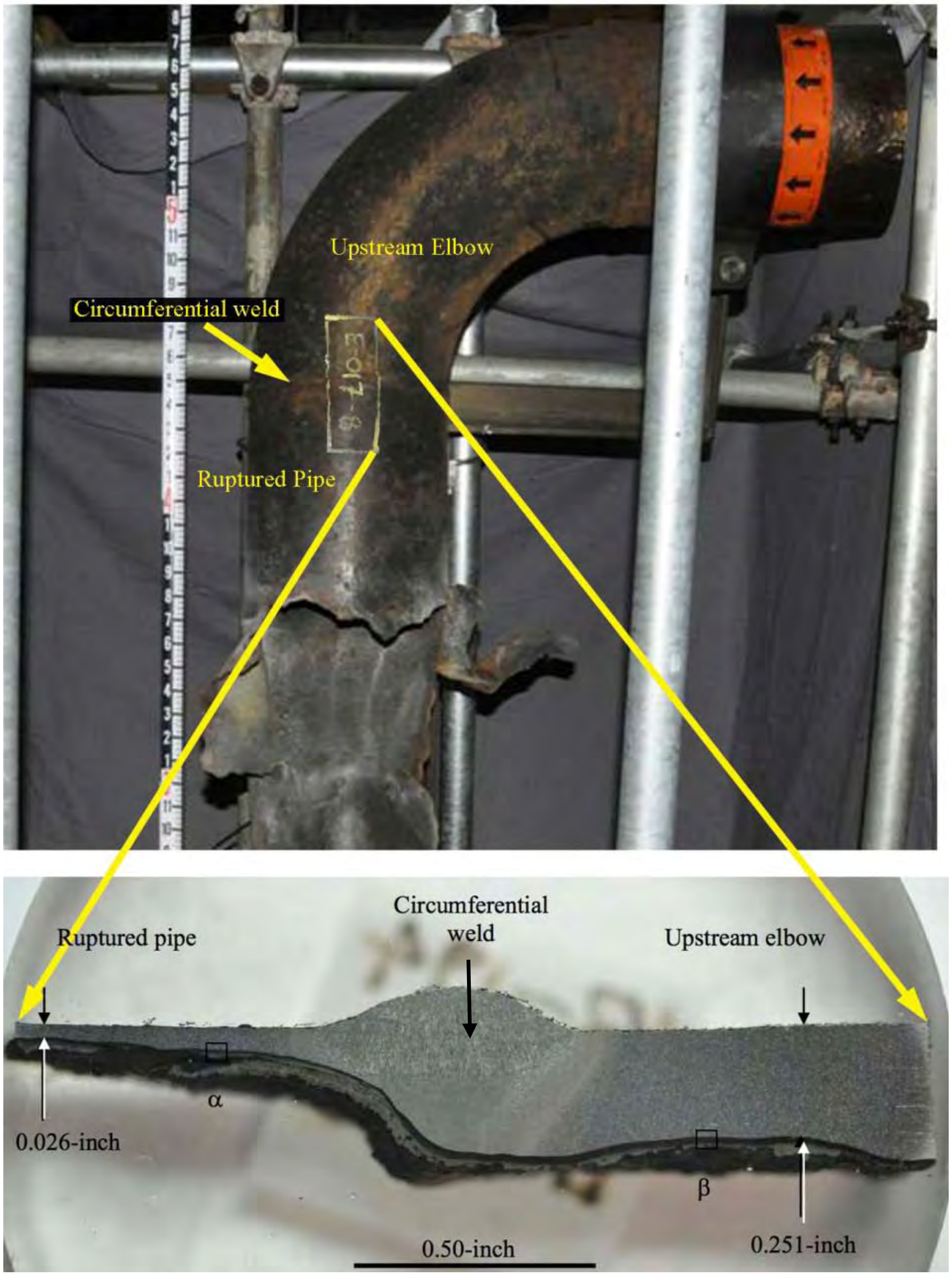

Figure 9. 4-sidecut piping sample (E-017-8) analyzed by Anamet Labs showing the relative thickness of low silicon piping on the left and the high silicon piping on the right. The ruptured pipe component (left) contained 0.01 % silicon and the upstream elbow component (right) contained 0.16 % silicon.[19] The initial nominal thickness of this piping was 0.322-inch.

Sulfidation Corrosion Inspection Techniques

15. As evidenced by the chemical analysis performed on the Chevron 4-sidecut piping post-incident, carbon steel piping components within a single circuit[i] can contain varying percentages of silicon, resulting in a large variation in sulfidation corrosion rates by component. Historically, sulfidation corrosion monitoring techniques required the measurement of pipe thickness at only a minimal number of permanent Condition Monitoring Locations (CMLs)[ii] along the piping. These CMLs are most frequently placed on elbows and fittings.[iii] However, due to details of the manufacturing process, carbon steel pipe fittings generally contain high percentages of silicon.[20] When measurements are only taken at high-silicon containing fittings, the measurements can fail to identify high corrosion rates within a pipe circuit caused by low-silicon components. At the Chevron Richmond Refinery, the 4-sidecut piping had a total of 24 CMLs[iv] on piping and fittings. The CSB found that there were no CMLs placed on the low silicon piping component that failed. Chevron identified accelerated corrosion in the 52-inch component in a 2002 inspection. However, no CML was added to ensure future monitoring, and the 52-inch component was not inspected again. Instead, the CSB found that Chevron relied on inspection data gained primarily from high silicon pipe-fitting components, such as elbow components. This inspection data did not reflect the corrosion rates of the lower-silicon components of the 4-sidecut piping. Relying on the limited inspection data from the CMLs on the high silicon components, Chevron management denied multiple recommendations to replace the 4-sidecut line. As illustrated by the Chevron incident, inspection techniques alone may not accurately identify the most aggressive corrosion rates throughout an entire circuit of carbon steel piping. Low-silicon components can remain uninspected and unidentified until failures such as the August 6, 2012, Chevron incident occur. As will be discussed below, upgrading metallurgy is a more effective means of managing sulfidation corrosion.

16. Determining silicon content in existing carbon steel piping and equipment in the field is a difficult undertaking. To properly characterize the silicon content in each component in a piping circuit, every component must be inspected. This is known as 100 percent component inspection. Two techniques are currently used to determine silicon content in existing carbon steel piping circuits with unknown chemical composition: performing chemical analysis and pipe wall thickness measurements of every component.

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[i] A piping circuit is a length of pipe and the fittings associated with a particular process service that operate at similar conditions. A circuit usually begins and ends at either a branch or a piece of process equipment such as a vessel or a pump. Reference to piping by circuits allows piping to be grouped conveniently by proximity and operating service. Piping circuits may also be referred to as piping runs.

[ii] A condition monitoring location (CML) is a designated area where periodic thickness examinations are conducted. Each CML represents as many as four inspection locations located circumferentially around the pipe. CMLs are also referred to as thickness monitoring locations (TMLs). CML was historically referred to as corrosion monitoring locations (CMLs) and that terminology is sometimes still used within the industry.

[iii] A fitting is a piping component usually associated with a change in direction or diameter.

[iv] Many of these CMLs were added during the 2011 turnaround.

17. Many field-portable instruments used for positive material identification cannot adequately identify silicon content.[21] If original manufacturing quality assurance data[i] are not available, as is generally the case with older plants, then chemical verification requires destructive testing. Metal shavings must be taken from each carbon steel piping component for chemical analysis in a laboratory.[22] This method requires that the insulation be removed for access to the piping so that each individual piping component can be sampled and verified.

18. Carbon steel components containing low concentrations of silicon can also potentially be identified by performing thickness measurements of every component within a carbon steel circuit.[23] This practice is only useful if the piping circuit has been exposed to sulfidation corrosion for a long enough time period so that variances in corrosion rate caused by differences in silicon content may be detected. Chemical analysis is therefore the most accurate technique to identify low-silicon carbon steel components. As with chemical analysis, the thickness measurement method requires that each individual piping component be identified by removing insulation (so every weld seam can be located), a time consuming and costly undertaking, or by using non-destructive examination techniques. Thickness measurements on high temperature piping typically can only be done accurately and safely during unit turnarounds.[ii] Although these various methods were available to detect the location of the field welds, Chevron had not used them to identify the 4-sidecut pipe segment locations.

19. API Recommended Practice 939-C *Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries* describes the challenges faced when attempting to thoroughly inspect carbon steel lines susceptible to sulfidation corrosion. The recommended practice states that older ASTM A53 piping, such as the Chevron piping that failed on August 6th, creates a "major inspection challenge"[24] and that "unless the refinery is fortunate enough to have located an inspection point on that particular [low silicon] section of pipe or fitting, it is very difficult to detect the thinning component."[25] It states that in some applications, carbon steel will appear to be adequate based on measured corrosion rates until failure occurs at some undocumented or unidentified low-silicon component.[26]

20. Unlike silicon concentration, the chromium concentration of steel can easily be verified in the field using portable positive material identification instruments. In addition, steel alloys containing at least 9 wt. % chromium are more resistant to sulfidation corrosion and do not run the risk of extreme variations in corrosion rates within components in the same piping circuit.[iii] This makes alloys with higher chromium content an inherently safer choice in high temperature

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[i] Manufacturing quality assurance data, also known as mill data, provides the chemical composition of the steel.

[ii] A "turnaround" is a scheduled shutdown of a process unit to perform maintenance, repairs, upgrades, and inspection of process equipment.

[iii] The protective scale, $FeCr_2S_4$, begins to be the dominant scale formed in steels containing a chromium content of five wt. %. The 5Cr steel alloy can be manufactured to contain anywhere from 4% to 6% chromium. Thus, "the sulfidation corrosion rate can vary dramatically in 5Cr steels even in the same operating environment." *See* Niccolls, E. H., J. M. Stankiewicz, J. E. McLaughlin, and K. Yamamoto. "High Temperature Sulfidation Corrosion in Refining." *17th International Corrosion Congress.* Las Vegas: NACE International, 2008.

sulfidation corrosion environments.[i] As shown in the Modified McConomy Curves[ii] from API RP 939-C (Figure 10), 9-Chrome[iii] corrodes 15 times faster than stainless steel,[iv] and carbon steel[v] corrodes 125 times faster than stainless steel.[27]

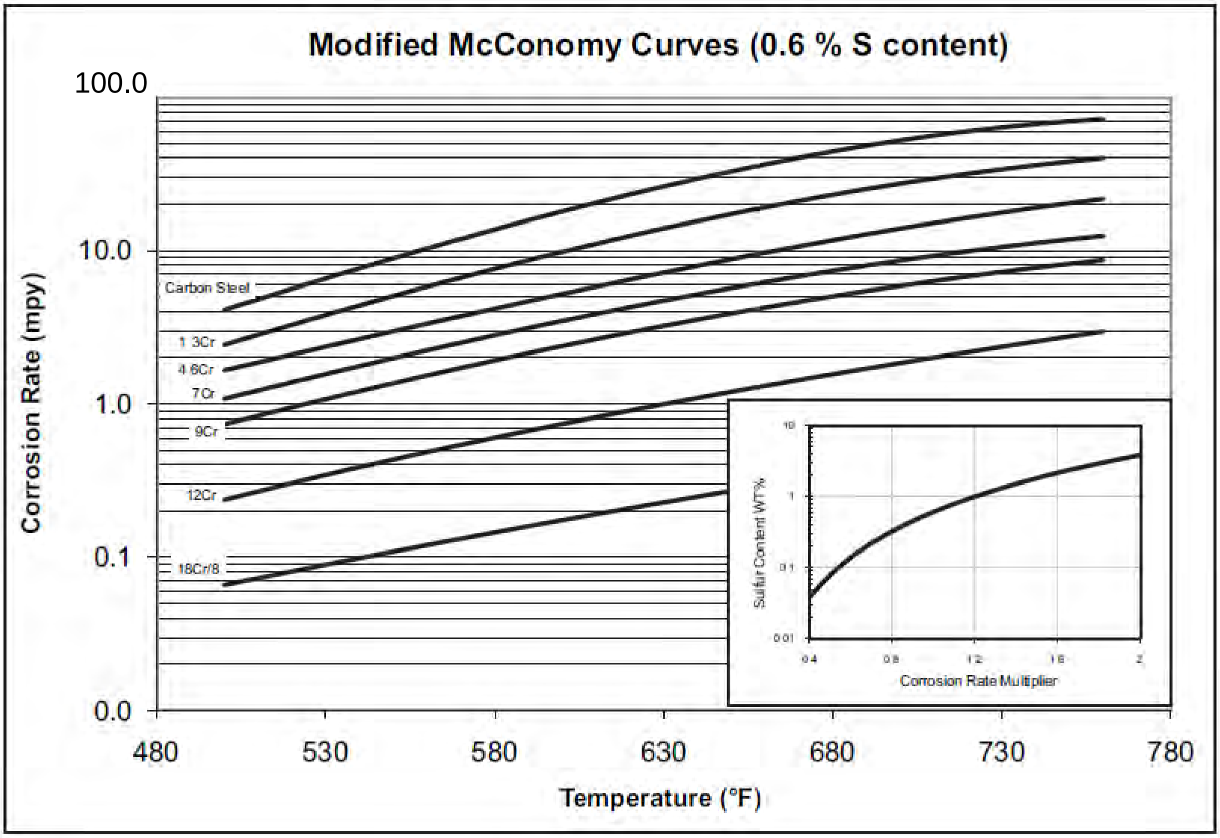

Figure 10. Modified McConomy Curves from API RP 939-C.

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[i] Steels with higher chromium content are inherently safer than carbon steel with respect to sulfidation corrosion. However, analysis is still required to ensure that the best material of construction is selected.

[ii] Modified McConomy Curves are the set of curves API RP 939-C uses to predict sulfidation corrosion rates versus temperature for several steel alloys.

[iii] 9-Chrome contains 9 wt. % chromium.

[iv] Stainless steel contains 18 wt. % chromium.

[v] ASTM A53B carbon steel contains a maximum of 0.40 wt. % chromium.

Chevron Sulfidation Corrosion Knowledge and Expertise

21. Figure 11 shows a timeline of Chevron's key sulfidation events. Chevron technical staff has considerable knowledge and expertise regarding sulfidation corrosion, specifically with respect to corrosion rate variations caused by differing silicon concentration in carbon steel piping. Chevron employees have authored industry papers on sulfidation corrosion and had significant influence in the development of the industry sulfidation corrosion recommended practice, API RP 939-C. This recommended practice, first published in 2009, was developed under Chevron leadership. At the approximate time of publication of API RP 939-C, Chevron Energy Technology Company (Chevron ETC)[i] created an internal document on the subject of sulfidation corrosion. Chevron ETC metallurgists released a formal report dated September 30, 2009 (nearly 3 years prior to the incident) to Chevron refinery-based reliability managers and chief inspectors entitled *Updated Inspection Strategies for Preventing Sulfidation Corrosion Failures in Chevron Refineries*.

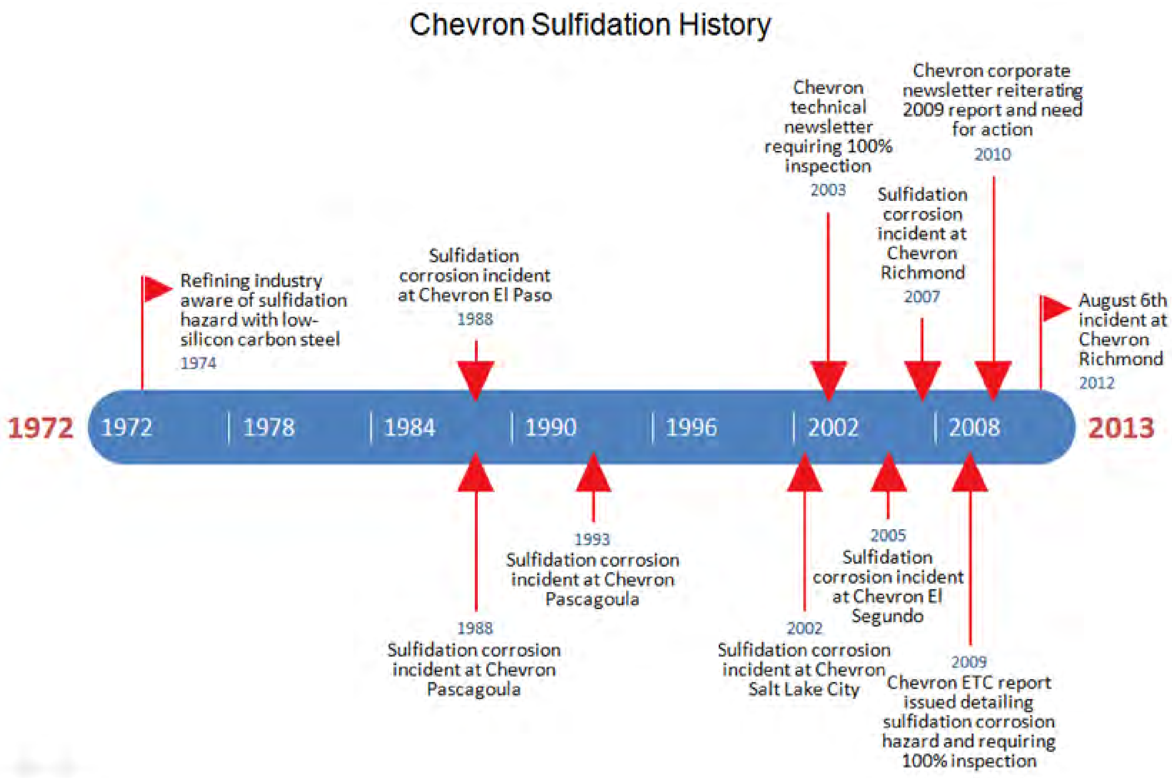

Figure 11. Chevron's key sulfidation events between 1974 and 2013.

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[i] The Chevron Energy Technology Company is a separate business unit within the Chevron Corporation that provides technology solutions and technical expertise for Chevron operations worldwide. *See* http://richmond.chevron.com/home/aboutchevronrichmond.aspx (accessed April 4, 2013)

22. Sulfidation experts acknowledged in the Chevron ETC report that, "Until now, Chevron has not directly addressed the risk of low Si[licon] carbon steel…"[i] and that the report lays out a program that "seeks to close these gaps, and to maximize the effectiveness of our inspection." The report clearly indicates that Chevron understood both the potential consequence and the high likelihood of a rupture or catastrophic failure from sulfidation corrosion and calls out Chevron's need for action:

> Sulfidation corrosion failures are not common in Chevron or in the industry but they are of great concern because of the comparatively high likelihood of blowout or catastrophic failure […] . This can happen because corrosion occurs at a relatively uniform rate over a broad area so a pipe can get progressively thinner until it actually bursts rather than leaking at a pit or local thin area. In addition the process fluid is often above its autoignition temperature. The combination of these factors means that sulfidation corrosion failures frequently result in large fires. […] [S]everal case histories of sulfidation corrosion failures that have occurred in Chevron or in the industry several of which are blowouts.

This Chevron ETC report specifically recommends that inspectors perform 100 percent component inspection on high temperature carbon steel piping susceptible to sulfidation corrosion. However, this 100 percent component inspection program was not implemented at the Richmond refinery prior to the August 6, 2012 incident. The Chevron ETC report defines a priority ranking system to help focus the inspection implementation efforts. The process conditions of the 4-sidecut stream placed it in the highest priority for inspection.

23. Chevron ETC technical experts issued a corporate newsletter in 2010 that again warned of the potential consequence of sulfidation failures. In this newsletter, the 100 percent component inspection recommendation from the 2009 report was reiterated for piping systems such as the crude unit 4-sidecut piping. The newsletter states:

> Sulfidation corrosion failures … are of great concern because of the comparatively high likelihood of "blowout" or catastrophic failure. This typically happens because corrosion occurs at a relatively uniform rate over a broad area, so a pipe can get progressively thinner until it actually bursts rather than leaking at a pit or local thin area. In addition, the process fluid is often above its autoignition temperature. The combination of these factors means that sulfidation corrosion failures frequently result in large fires. Chevron and the industry have experienced numerous failures from this mechanism and recent incidents have reinforced the need for revised inspection strategies and a robust PMI (Positive Materials Identification) program.

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[i] A 2003 corporate technical newsletter recommended 100 percent component inspection of carbon steel piping susceptible to sulfidation corrosion following a 2002 Chevron Salt Lake City sulfidation corrosion incident.

The Chevron ETC 100 percent component inspection recommendation for high risk piping systems, established in 2009, was not implemented at Richmond; therefore, the thin-walled low silicon 4-sidecut piping component remained in service until it catastrophically failed on August 6, 2012.

24. Chevron and Chevron ETC metallurgists, materials engineers, and piping inspectors had expertise regarding sulfidation corrosion. They educated personnel and advocated for identification and control of damage mechanisms, including sulfidation corrosion. However, they had limited practical influence to implement their recommendations. These individuals did not participate in the crude unit Process Hazard Analysis (PHA)[i] and did not affect decisions concerning control of sulfidation corrosion during the crude unit turnaround process.[ii]

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[i] A process hazard analysis is a hazard evaluation to identify, evaluate, and control the hazards involved in a process. Facilities that process a threshold quantity of hazardous materials, such as the Chevron Richmond refinery, are required to conduct a process hazard analysis per the California Code of Regulations Title 8 Section 5189. Process Safety Management of Acutely Hazardous Materials (1992). PHAs are also required by the California Accidental Release Prevention Program and the federal EPA Risk Management Program.

[ii] The turnaround process includes both the planning stage prior to the shutdown and the activities staged during the shutdown.

Other Significant Sulfidation Occurrences

25. The refining industry has experienced numerous sulfidation corrosion failures, primarily in piping.[28] API RP 939-C identifies 45 sulfidation corrosion failures, one third of which were found to have occurred in carbon steel piping containing low levels of silicon.[29]

26. The August 6, 2012, Chevron Richmond Refinery 4-sidecut pipe rupture was not the first sulfidation corrosion-related incident to occur at a Chevron refinery. In 1988, a low silicon carbon steel (0.02 wt. % silicon) piping component failed at the Chevron's former El Paso Refinery[i] in El Paso, Texas. In addition, two sulfidation corrosion incidents occurred at the Chevron Pascagoula refinery in Pascagoula, Mississippi: one in 1993 and one in 1988 on a low-silicon carbon steel component.

27. In 2002, the Chevron Salt Lake City Refinery experienced a fire when process piping failed as a result of sulfidation corrosion in a low silicon ASTM A53 carbon steel piping component. Chevron communicated the incident throughout the company in a technical newsletter. Chevron experts found that despite regular monitoring of the line for 30 years in compliance with industry standards, their inspection program failed to prevent the failure. Corrosion rates at the unmonitored failure location were found to be five times greater than corrosion rates at the monitored piping locations. The monitored locations were constructed of high silicon ASTM A106 piping (Figure 12). Chevron also found that in the years preceding the failure, both the temperature[ii] and hydrogen sulfide concentration in the process had been increasing. Each of these factors increased corrosion rates and contributed to the failure. In 2003, following this incident, Chevron experts recommended that refineries inspect every piping component (100 % component inspection) in all high-risk piping systems: those operating above 550 °F and containing hydrogen sulfide.

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[i] The El Paso Refinery is now owned by Western Refining.

[ii] The temperature in the line had been increased by over 170 °F throughout the life of the unit. During the two years prior to failure, temperatures of the line exceeded the measurement capabilities of the temperature measurement device and so the actual temperature increase cannot be determined.

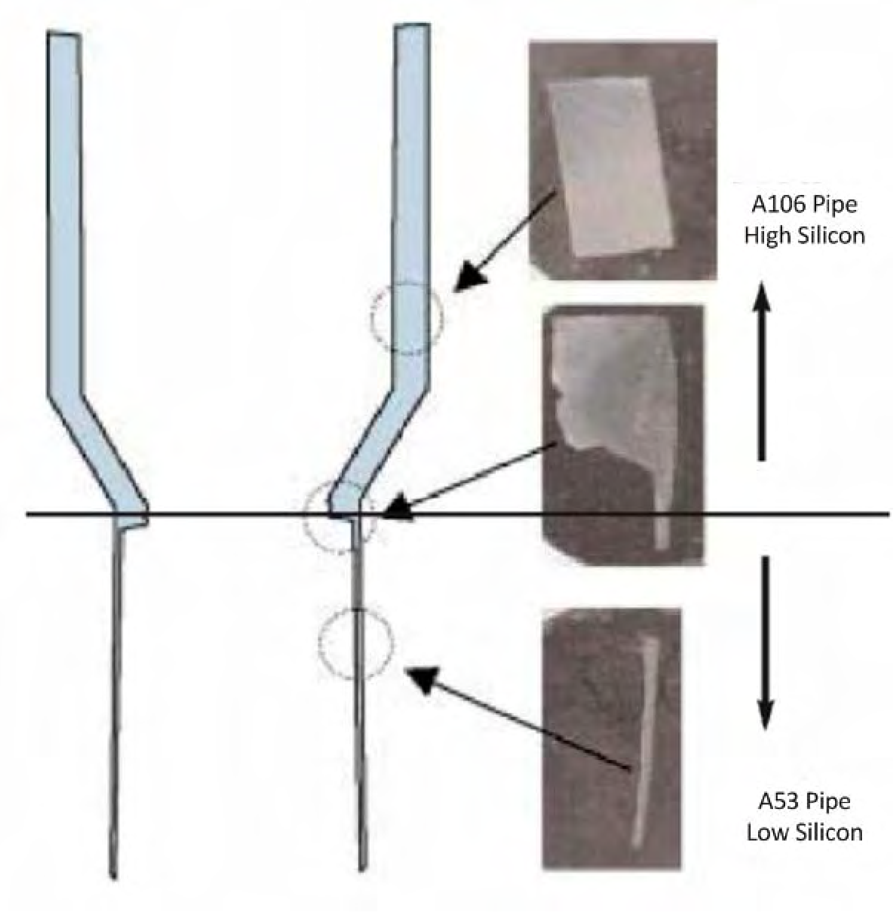

Figure 12. Schematic of failed piping from the Chevron Salt Lake Refinery. Similar to the Chevron Richmond Refinery incident, the failed piping contained low amounts of silicon and corroded significantly faster than adjacent piping components.

28. In January 2007, a failure due to sulfidation corrosion caused a serious fire in the Chevron Richmond Refinery crude unit resulting in a CWS Level 3 alert, initiating a shelter-in-place for the surrounding community. A carbon steel piping spool[i] failed catastrophically during operation (Figure 13). The carbon steel piping contained a low percentage of silicon (<0.005 wt. %). The process fluid ignited, injuring a nearby worker. Chevron informed Contra Costa Health Services' Hazardous Materials Program[ii] (Contra Costa County) in a letter that the metallurgy had been upgraded following this incident as an inherently safer solution. However, the CSB learned that this upgrade was limited to only the immediate piping spool that failed. The inherently safer, more corrosion resistant metallurgy was not implemented more broadly in crude unit high temperature service as a result of this incident.

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[i] A piping spool is a small, removable section of piping. In some cases, a piping spool is installed or removed in order to provide a temporary connection or complete disconnection between two piping circuits.

[ii] Contra Costa Health Services' Hazardous Materials program is designed to respond to emergencies and monitor hazardous materials within Contra Costa County. *See* http://cchealth.org/hazmat/ (accessed April 17, 2013).


Thickness measured between 0.014" - 0.042" along the edges of the primary fracture surface (expected range was between 0.207" - 0.266").

Figure 13. Failed piping component that resulted in the 2007 Richmond crude unit fire. This carbon steel piping was found to contain less than 0.005 percent silicon.

29. Following the August 6, 2012, incident, personnel at the Chevron El Segundo, California, refinery, a near duplicate of the Richmond refinery, inspected their refinery's crude unit 4-sidecut piping. Significant thinning was discovered in the line; the piping from the atmospheric crude column to the pumps was removed and substituted with 9-Chrome, an upgraded and inherently safer material of construction.

30. On November 9, 2009, the Silver Eagle refinery in Woods Cross, Utah, experienced a catastrophic piping failure due to sulfidation corrosion in a 10-inch pipe, while conducting a temporary operation at higher than normal operating temperature. The pipe was located on the

bottom of a reactor in the de-waxing unit. The failed pipe released hydrogen which subsequently exploded, damaging over 100 homes in the nearby neighborhood.

31. On October 6, 2011, an explosion and fire resulted from a catastrophic piping failure at a Canadian refinery in Regina, Saskatchewan, injuring 52 workers. The piping component that failed was substantially thinner than neighboring components. Prior to the incident, the company's inspection data indicated that wall thickness in the overall piping system was within acceptable limits. However, the specific component that failed was not inspected. Although Canadian authorities are still investigating, metallurgical testing has indicated that hydrogen sulfide corrosion contributed to the catastrophic failure.

32. In February 2012, the BP refinery crude unit in Cherry Point, Washington, suffered a failure due to sulfidation corrosion, causing a large fire. This incident demonstrates that even when applying inherently safer concepts to reduce the potential for major hazards, it is still vital to fully understand all processes and piping configurations and incorporate a rigorous inspection program. The piping that failed was constructed of 9-Chrome. The line was used only during start-up operations and otherwise remained in-service and non-flowing. Such lines that do not have regular process flow yet remain in contact with process fluids are commonly referred to as "dead legs." The failure location was a high-point in the piping connected to the top of an operating process line. Hydrogen sulfide evolved from the process fluid and collected in the 9-Chrome piping. The concentrated vapor-phase hydrogen sulfide severely corroded the 9-Chrome, causing the failure. CMLs were located on adjacent elbow components; however, no CMLs were placed on the straight-run piping component where the failure occurred. The Cherry Point sulfidation failure demonstrates that even with more corrosion-resistant, inherently safer metallurgy, failure from sulfidation corrosion still may occur if piping is not effectively inspected or piping configurations are not adequately evaluated. In addition it is important to conduct a thorough analysis to determine the best material of construction for the process conditions.

Process Hazard Analysis

33. Chevron personnel analyze numerous deviations[i] for each portion of a process when conducting a Process Hazard Analysis (PHA). These include conditions such as changes in flow and temperature and pressure extremes. Specifically of interest, one of the deviations analyzed was "leak/rupture" of the particular vessel or pipe. For each deviation, the team's responsibility was to identify causes, consequences, safeguards, and recommendations. The 4-sidecut line was analyzed in the most recent crude unit PHA. Corrosion was *not* identified as a potential cause of a leak/rupture in the piping (emphasis added).

34. Sometimes referred to as a corrosion review, a damage mechanism hazard review analyzes risks presented by all process failure mechanisms such as corrosion and cracking. Common process failure mechanisms are described in API 571: *Damage Mechanisms Affecting Fixed Equipment in the Refining and Petrochemical Industries*.[30] Such a review ensures that potential hazards caused by process conditions, process materials, and external mechanisms are properly identified, analyzed, and systems are put in place to control or eliminate the hazard. Despite Chevron knowledge and expertise of potential damage mechanisms (such as sulfidation corrosion), the CSB found these hazards are only identified in a PHA if the participants conducting the PHA happen to have personal knowledge of the relevant mechanism. The Chevron PHA teams do not typically seek assistance from corrosion experts.[ii] The inclusion of a damage mechanism hazard review as part of the PHA is not required by the state of California, the California Division of Occupational Safety and Health (Cal/OSHA),[iii] Contra Costa County, the City of Richmond,[iv] or Chevron standards. Because Chevron does not conduct, and is not required to conduct, a formal damage mechanism hazard review, damage mechanisms are only identified when the PHA team happens to have some knowledge of the mechanism. As a result, many damage mechanisms which occur in various processes are not properly addressed.

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[i] Deviations using guide words (such as no, more, less, as well as) and process parameters (such as flow, pressure, temperature) are analyzed in PHAs. *See* Center for Chemical Process Safety (CCPS). "Guidelines for Hazard Evaluation Procedures." 2nd ed., Page 132, 1992.

[ii] The Crude Unit Business Improvement Network (BIN) Leader, a crude unit expert, reviews portions of the PHA with the PHA team. However, this review did not identify the potential for sulfidation corrosion failures in the 4-sidecut piping. A rigorous review of corrosion and damage mechanisms present in the crude unit was not performed during the PHA process.

[iii] The state of California, under an agreement with the federal Occupational Safety and Health Administration, or OSHA, operates an occupational safety and health program in accordance with Section 18 of the Occupational Safety and Health Act of 1970. *See* http://www.osha.gov/dcsp/osp/stateprogs/california.html (accessed April 17, 2013). The Department of Industrial Relations administers the California Occupational Safety and Health Program, commonly referred to as Cal/OSHA. The program applies to all public and private sector places of employment in the state, with some exceptions. *See* http://www.dir.ca.gov/dosh/dosh1.html (accessed April 17, 2013).

[iv] The City of Richmond adopted an ordinance on Industrial Safety, Richmond Municipal Code Chapter 6.43 (also known as the RISO), on December 18, 2001, "for the purposes of protecting public health and safety by prevention of accidental release of hazardous materials and to assure protection of the environment." Richmond Municipal Code §6.43.040 (February 5, 2013). There are two facilities, including Chevron, that are located in the City of Richmond and subject to this ordinance. More information about the RISO is provided later in the report.

35. During a hazard analysis process such as a PHA, the evaluation team has to determine the likelihood of a hazardous consequence occurring. Then the team must identify safeguards which will reduce the risk of the hazard to an acceptable level. A recognized methodology for consistently and objectively making these determinations could include the use of quantitative, semi-quantitative, or qualitative tools.[31] Chevron does not employ a prescribed methodology for determining the likelihood that an incident will occur or whether a safeguard will be effective. Instead, Chevron relies upon the judgment of the people on the PHA team, who base their conclusions upon their collective experiences, beliefs, and areas of expertise. In its 2009 crude unit PHA, Chevron simply cited non-specific, judgment-based qualitative safeguards such as: utilizing metallurgy to minimize corrosion, having effective maintenance and inspection programs, and providing pipe wall corrosion allowances.[i] The effectiveness of these safeguards was neither evaluated nor documented; instead the safeguards were merely listed in the PHA. Had the adequacy of these safeguards been verified, improved safeguards intended to protect against sulfidation-induced failure of carbon steel piping could have been recommended.

36. Following the August 6th incident, Cal/OSHA inspected the Chevron facility and issued citations. Only one citation related to PHAs, and it was not associated with evaluating the effectiveness of safeguards. Rather, the emphasis was that Chevron's PHA did not adequately account for hazards caused by other units associated with the crude unit. The citation stated "The Employer [Chevron] failed to perform an effective Process Hazard Analysis [PHA] of the crude unit. Specifically, it failed to identify, evaluate, and control potential hazards caused by upstream and downstream units that provide and receive feed from the crude unit."[32] Had the Cal/OSHA regulation required documentation of the effectiveness of safeguards, Chevron would have been obligated to conduct this analysis and Cal/OSHA inspectors could rely on the regulation for support during inspections.

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[i] Corrosion allowance refers to extra wall thickness added as a safety factor to the design of a piece of equipment beyond that needed solely for mechanical considerations such as design temperature and pressure. This extra thickness is provided to accommodate for expected loss of wall thickness due to corrosion over the life of the equipment.

Operational Changes

37. The original design of the 4-sidecut circuit included equipment which had the effect of removing dissolved hydrogen sulfide, the most aggressive sulfur compound associated with sulfidation corrosion, from the 4-sidecut light gas oil process fluid. As a result, the 4-sidecut equipment was effective in reducing the sulfidation corrosion rate. This allowed the 4-sidecut equipment to be constructed of carbon steel. In 1991, this 4-sidecut equipment was taken out of service. No management of change[i] (MOC) was performed to analyze the effect of the elimination of this hydrogen sulfide-removing equipment on 4-sidecut corrosion rates. Such an MOC would have ensured that the increase in sulfur concentration on the carbon steel 4-sidecut piping was reviewed prior to removing the equipment.

38. Crude oil feedstock used at the Chevron Richmond Refinery is obtained from a variety of different sources that are blended before processing. These various crudes have different compositions, such as varying sulfur compounds and concentrations. These crudes can have differing corrosion effects on process equipment and piping. There is an increasing trend in crude oil refining to process less expensive “opportunity crudes” because they can provide significant cost savings to the company.[ii] However, these crudes may contain more undesirable characteristics such as high sulfur content, high naphthenic acid content, or very heavy hydrocarbons[33] that a refinery may not have been originally designed to process. Refinery equipment may not be the proper material of construction to achieve the design life of the equipment when exposed to the different operating conditions. Additional mitigation may be needed to reduce risk. In 1984, the Chevron Richmond Refinery crude oil feed contained approximately 85 volume % Alaskan North Slope (1 wt. %) crude oil. As the refinery began running more high-sulfur content crudes, the sulfur content in the 4-sidecut line steadily increased (Figure 14), as discussed below.

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[i] Management of change requires that employers have procedures to manage changes to process chemicals, technology, equipment, and procedures. The procedures must address the technical basis for the change, the impact on safety and health, and training required for employees affected by the change.

[ii] Crude oil costs can account for up to 90% of the operating costs in a refinery. *See* Qu, Dingrong, Xiaohui Liu, Xiu Jiang, Zhenggui Lan, and Guangbin Shan. “Setting Critical Operational TAN and Sulfur Level for Crude Distillation Units.” *Corrosion 2011 Conference & Expo.* Paper No. 11362. NACE International, 2011.

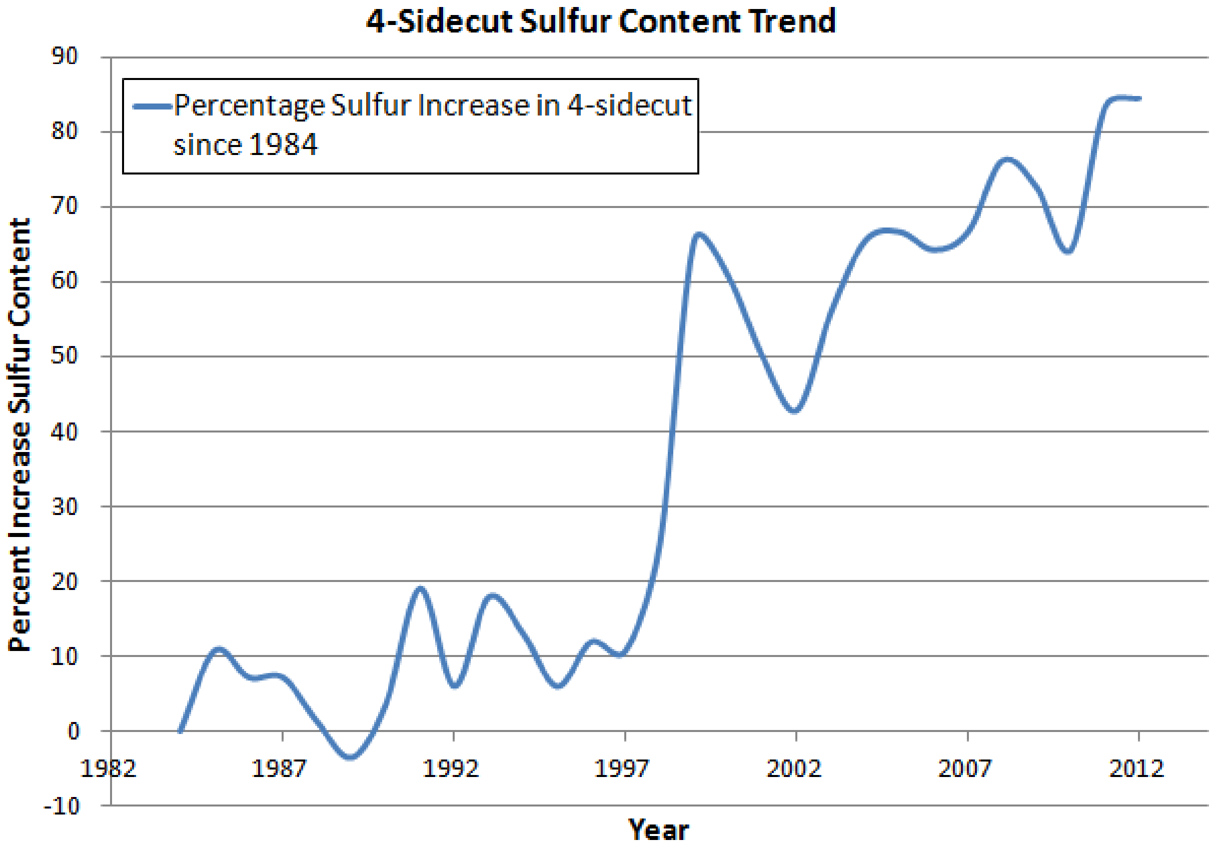

Figure 14. Graph shows the percentage increase from 1984 values of the sulfur content in the 4-sidecut.

39. When Chevron introduces a new crude, an MOC is generated to evaluate the potential impact on the refinery.[i] 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. Historic data indicates that the sulfur in the 4-sidecut stream has increased from 0.8 to 1.6 wt%. This increase in sulfur composition likely increased corrosion rates in the 4-sidecut line. Chevron did not conduct an MOC analyzing the impact that increases in sulfur composition would have on corrosion in the crude unit. Chevron also did not change its corrosion monitoring programs in response to the increased sulfur content.

40. The CSB found that increased Chevron Richmond usage of non-domestic crude feed stock over time resulted in higher sulfur content in the process fluid passing through the 4-sidecut piping. Specifically, the percentage of sulfur in the Richmond refinery crudes increased nearly 85% between 1984 and 2012, including a significant jump of 32% from 1998 to 1999. This increase in sulfur content corresponded with a simultaneous increase in the usage of non-domestic crude feed at the Richmond refinery.

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[i] Chevron MOCs on new crudes considered general operational issues but did not analyze corrosion effects from sulfidation corrosion.

41. Sulfidation corrosion rates increase in piping circuits as temperature and sulfur content increase. Accordingly, the 4-sidecut sulfidation corrosion rate increased between 1984 and 2012 due to the increase in sulfur content in the line. The CSB found that for the 26-year period from the installation of the piping in 1976 through 2002, the 52-inch 4-sidecut component had lost approximately 33 percent of its wall thickness. From the single inspection of the 52-inch component in 2002 to the incident in 2012 – just ten years – an additional 57 percent of the original component nominal wall thickness was lost near the rupture location due to sulfidation corrosion.[i] In addition to the sulfur content increase, the 4-sidecut draw temperature increased from 625 °F in 1992 to 680 °F in 2002. Corrosion rates and remaining life calculations based on past sulfur content and temperatures may not accurately reflect current corrosion rates if process conditions have changed. Inspection based on historical corrosion rates may be too infrequent to detect an increase in corrosion caused by adverse changes in process conditions, potentially leading to equipment failure.

42. API RP 939-C states that refinery feed stock changes reduce the relevance of past inspection data when predicting future corrosion rates:

> Oil refineries that processed a consistent diet of a particular crude oil or crude blend could often base future predictions on past experience. However, over the past 20+ years, global economics have resulted in many refineries processing tens of different crudes in any given year; thus, minimizing the accuracy, or even feasibility, of predictions based on historical data. Additionally, the verification of the actual corrosion rate experienced while processing a specific crude oil is very difficult.[34]

43. API 570 *Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems*, the API standard for inspecting piping, recommends companies to incorporate process changes into inspection programs. The standard states:

> The owner/user is … responsible for implementing an effective MOC process that will review and control changes to the process and to the hardware. An effective MOC process is vital to the success of any piping integrity management program in order that the inspection group will be able to anticipate changes in corrosion or other deterioration variables and alter the inspection plan to account for those changes. The MOC process shall include the appropriate materials/corrosion experience and expertise in order to effectively forecast what changes might affect piping integrity. The inspection group shall be involved in the approval process for changes that may affect piping integrity.

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[i] The 4-sidecut 52-inch component had an original wall thickness of 0.322 inches. Metallurgical analysis found the thinnest portion of the 52-inch 4-sidecut component was 0.03 inches.

> *Changes to the hardware and the process shall be included in the MOC process to ensure its effectiveness* [emphasis added].[35]

Chevron failed to comply with the requirements of API 570 when it did not conduct an MOC to thoroughly evaluate the change of increasing sulfur weight percentage in crude oil feed and to assess how it might affect corrosion rates within the 4-sidecut piping circuit. After the August 6, 2012, incident, Cal/OSHA inspected the Chevron Richmond Refinery and issued citations.[i] However, Cal/OSHA did not issue any citations for failing to perform an MOC when sulfur composition in the crude oil feed was increased.

Chevron Sulfidation Corrosion Inspection and Mitigation

44. In the ten years prior to the incident, a small number of Chevron personnel with knowledge and understanding of sulfidation corrosion made at least six recommendations (listed in the following six paragraphs and included in Figure 15) to increase inspections or upgrade the metallurgy in the 4-sidecut piping. The recommendations made by these personnel were not implemented by Chevron management.

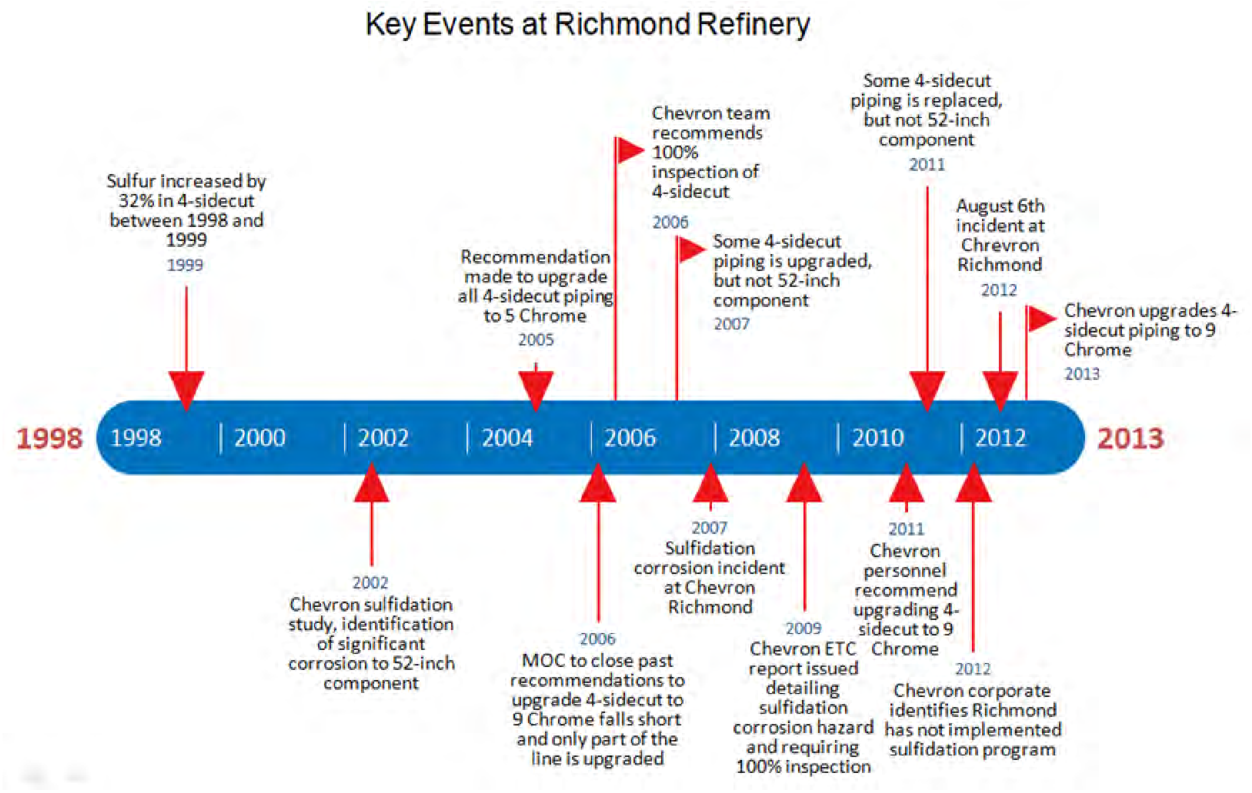

Figure 15. Key events at the Richmond refinery between 1998 and 2013.

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[i] Cal/OSHA citations issued January 30, 2013.

45. In August 2002, a Chevron Richmond Refinery employee performed a study analyzing sulfidation corrosion rates in the crude unit and identifying potentially vulnerable areas. The employee discovered that the 4-sidecut operating temperature had been increased and concluded that this increase would cause more hydrogen sulfide to evolve, leading to increased sulfidation corrosion rates. As a result of these findings, the employee recommended increased inspection of the 4-sidecut piping and noted that this piping might need to be upgraded from carbon steel to 5-Chrome, a steel alloy that is more resistant to sulfidation corrosion. In 2002, proactively following up on this study, the crude unit inspector conducted additional piping inspection and identified accelerated corrosion in the 52-inch 4-sidecut component. The inspector recommended upgrading this piping during the next shutdown in 2007. In the inspector's 2002 accomplishments, Chevron management acknowledged this effort to prevent a significant incident; it was characterized as "a save." However, during the 2007 turnaround the recommendation was not implemented, and because a CML was not added to the inspection program, the 52-inch component was not inspected after 2002.

46. In February 2006, a team consisting of a materials and corrosion engineer, an inspector, a process engineer, a metallurgist, and a design engineer issued a Corrosion Mitigation Plan for the Chevron Richmond Refinery crude unit. The report specifically identified the 4-sidecut piping to be at risk for high temperature sulfidation corrosion. The report described that low silicon carbon steel can corrode faster than carbon steel manufactured with higher silicon content, and recommended that 100 percent inspection be performed on the 4-sidecut line using continuous monitoring technology. During the 2007 crude unit turnaround, continuous monitoring probes were only installed on a segment of the 4-sidecut line that did not include the 52-inch component that ultimately failed. The 100 percent inspection recommended in the 2006 Corrosion Mitigation Plan was not performed.

47. During the 2007 turnaround, the crude unit inspector recommended that the refinery upgrade the entire 4-sidecut piping with 5-Chrome. The recommendation was based on findings obtained during the 2002 crude unit turnaround, where the crude unit inspector found that the 52-inch 4-sidecut component had lost one-third of its wall thickness due to corrosion. However, after evaluation, this recommendation was not accepted by the turnaround planning team. Basing its decision on limited inspection data, Chevron determined that the 8-inch portion of the 4-sidecut piping that ran from the atmospheric column to the pump, the portion which included the 52-inch component, had sufficient wall thickness to last to the next turnaround scheduled for Fall 2011.[i] The piping downstream of the pump, which operates at a higher pressure, was determined not to have sufficient wall thickness to last to the next turnaround. This piping was removed and replaced with 9-Chrome, an upgraded and inherently safer metallurgy. The 52-inch component of the 8-inch piping between the atmospheric column and the pump was not replaced during the 2007 turnaround even though it had been identified as thinned in 2002.

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[i] This decision was made without reinspecting or evaluating the thickness of the thinned 52-inch component identified in 2002 that prompted the recommendation.

Furthermore, a permanent CML was not placed on the 52-inch component, and it was not entered into the inspection database. As a result, the component was not inspected again.

48. In September 2009, Chevron ETC corrosion experts released a formal technical report discussing sulfidation corrosion and the specific issues associated with carbon steel, including the potential for high corrosion rates in carbon steel piping containing low percentages of silicon. In its report, Chevron ETC issued recommendations for inspection and provided guidelines for prioritizing piping circuits susceptible to sulfidation corrosion so that high-risk lines could be evaluated first. It was recommended that 100 percent component thickness testing be completed on all high priority lines one time to identify thin, low-silicon components to establish a baseline of corrosion rate and risk for failure. Following the release of the report, the Chevron Richmond Refinery materials group completed the risk-ranking of the carbon steel piping in the Richmond Lube Oil Project (RLOP) and in the crude unit, two units known to be susceptible to sulfidation corrosion. The group identified the crude unit 4-sidecut line as a high risk line per the report ranking guidance. Instead of completing the 100 percent component inspection, the 4-sidecut was recommended for replacement with 9-Chrome. However, the replacement recommendation was denied because the available, limited inspection data indicated the piping would last until the next turnaround. Subsequently, the alternative 100 percent component inspection was also never performed.

49. Five months prior to the incident in March 2012, a Chevron corporate review of Richmond identified that inspection of all carbon steel components susceptible to sulfidation corrosion was not being performed at the Richmond refinery. In addition to identifying that CMLs were not in the proper locations, this corporate review found that critical inspection recommendations were being submitted to the shutdown planning process, but were being denied. Chevron corporate identified that Richmond refinery leadership needed to review and implement the 2009 Chevron ETC report recommendations.

50. Chevron conducts “Intensive Process Reviews” prior to turnarounds. This process involves knowledgeable individuals including Business Improvement Network leaders, process engineers, metallurgical engineers, design engineers, and turnaround planners. The purpose of the review is to identify key unit issues that should be addressed and repaired during the unit turnaround. Prior to the 2011 crude unit turnaround, Chevron personnel conducted an Intensive Process Review of the crude unit and specifically recommended that the 4-sidecut carbon steel piping “should be upgraded to 5 Cr [5-Chrome]… due to sulfidation.” Although the Intensive Process Review identified sulfidation problems in the 4-sidecut line, this activity was ineffective. The 4-sidecut piping was not upgraded during the 2011 crude unit turnaround.

51. In preparation of the work list for the 2011 crude unit turnaround, the crude unit inspector and crude unit metallurgist recommended that the 4-sidecut line be replaced with an upgraded metallurgy, 9-chrome, the metallurgy recommended in the Chevron new construction guidelines for piping in high temperature and high sulfur service. The recommendation was based on the

high priority ranking of the 4-sidecut line, corrosion history, and both Chevron and industry recommended best practice. However, the turnaround management team determined that the inspection data available for the 4-sidecut piping, from CMLs on elbow components which are less prone to sulfidation corrosion, did not support a material upgrade during the 2011 turnaround.[i, ii] The lack of data on the more susceptible 4-sidecut straight-run piping components was not considered.

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[i] This decision was made without reinspecting or evaluating the thickness of the 52-inch component identified in 2002.

[ii] A portion of the 4-sidecut 12-inch line was replaced during the 2011 turnaround with carbon steel due to thinning caused by sulfidation corrosion.

Inherently Safer Systems

52. The Center for Chemical Process Safety (CCPS) is a corporate membership organization that identifies and addresses process safety needs within the chemical, pharmaceutical, and petroleum industries.[36] Chevron is a corporate member of CCPS.[37] The CCPS book *Inherently* Safer *Chemical Processes, 2nd ed.* defines inherently safer design as the process of identifying and implementing inherent safety in a specific context that is permanent and inseparable.[38] In the book *Guidelines for Engineering Design for Process Safety, 2nd ed.*, CCPS states "inherently safer design solutions eliminate or mitigate the hazard by using materials and process conditions that are less hazardous."[39]

53. Inherently safer technologies are relative; a technology can only be described as inherently safer when compared to a different technology with regard to a specific hazard or risk.[40] A technology may be inherently safer with respect to one risk but not safer from another risk. For this reason, it is important to carry out a comprehensive, documented hazard analysis to determine the individual and overall risks in a process and assess how the risks can be effectively minimized to control hazards. An inherently safer systems review details a list of choices offering various degrees of inherently safer implementation. The review should include risks of personal injury, environmental harm, and lost production, as well as evaluating economic feasibility.[41]

54. It is simpler, less expensive, and more effective to introduce inherently safer features during the design process of a facility rather than after the process is already operating.[42] Process upgrades, rebuilds, and repairs are additional opportunities to implement inherent safety concepts. Conducting a comprehensive hazard review to determine risks and identify ways to eliminate or reduce risks is an important step in implementing an inherently safer process. Chevron training programs on inherently safer systems reflect this approach, stating "we have the greatest opportunity to eliminate or minimize hazards during the development phase of new projects or major revamps of existing facilities."

55. After a 2007 incident caused by a pipe failure in the Richmond refinery crude unit, Chevron implemented an "Inherently Safer Solution" by upgrading the piping to metallurgy that was less susceptible to sulfidation corrosion. However, the change was implemented intuitively without a supporting inherent safety review or failure mechanism hazard review to provide a detailed documented technical rationale for the metallurgy selection. Without such a review, the material selected cannot be analyzed to determine if it is the best inherently safer solution for the process in order to minimize risk.

56. Following the August 6, 2012, incident, the 4-sidecut piping circuit at the Richmond refinery was upgraded from carbon steel to 9-Chrome.[i] However, Chevron did not produce a documented inherently safer hazard review before commencing the rebuild of the crude unit. The crude unit at the Chevron El Segundo refinery is nearly identical in construction and design to the Richmond refinery crude unit. Chevron informed the CSB that piping *downstream* of the 4-sidecut pumps in the 4-sidecut piping circuit at the El Segundo refinery was upgraded in 2001[ii] from carbon steel to stainless steel. As stated previously, after the August 6, 2012, Richmond incident, the 4-sidecut piping *upstream* of the 4-sidecut pumps at the El Segundo refinery was upgraded from carbon steel to 9-Chrome. Had a comprehensive inherently safer systems review been conducted at the Richmond refinery following the August 6th incident, a different metallurgy, such as stainless steel which was installed at the Chevron El Segundo Refinery, may have been identified as inherently safer than 9-Chrome with respect to sulfidation corrosion.

57. An effectiveness ranking of techniques used to control hazards and the risk they represent can be described as a hierarchy of controls. The further up the hierarchy, the more effective the risk reduction achieved (Figure 16). All concepts in the hierarchy of controls should be included in the process of risk assessment and reduction. Upgrading metallurgy to a more corrosion resistant material may be a high ranking, inherently safer choice for certain corrosion mechanisms, such as sulfidation corrosion. Holding other variables constant, upgrading the material of construction may reduce the severity of corrosion and the likelihood of a failure.

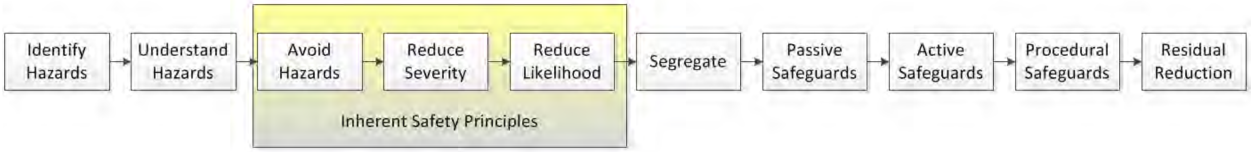

Figure 16. Hierarchy of controls. The boxes reflect inherently safer controls from left to right, based on *Process Plants: A Handbook for Inherently Safer Design Second Edition*; Kletz, Trevor Amyotte, Paul; CRC Press 2010.

58. Chevron employees have recommended implementing inherently safer designs through the MOC process, incident investigations, technical reports, and recommendations from employees in the past. However, the CSB has not identified any documented, thorough analysis of the proposed inherently safer solutions. In addition, Chevron has repeatedly failed to implement proposed inherently safer recommendations. For example, following the discovery of significant 4-sidecut piping sulfidation corrosion in 2002, a Chevron inspector issued the following recommendation to replace the piping in the 2007 turnaround:

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[i] After the 2012 incident, the Richmond refinery stated that stainless steel was susceptible to chloride stress corrosion cracking and should not be used.

[ii] Chevron verbal estimate for date of piping installation. No MOC was conducted to review and document this change.

> INFORMATION
>
> The #4 sidecut piping from C-1100 to P-1149/A to E-1113 was RT (x-ray) inspected for hot H2S [sulfidation] corrosion. The piping is actively corroding, particularly on the section on the discharge line from the pumps near the exchanger; the line upstream of the P-1149/A pumps is corroding as well. Corrosion rates indicate that the piping has 4 years of remaining life until the refinery throwaway thickness of 0.14” [inch] is reached. The carbon steel piping is currently running at temperatures between 650 °F on the pump suction line to 641 °F on the line just before E1113; the upper limit for carbon steel piping in this service is 550 °F. A materials upgrade to 5 chrome would raise the upper limit to between 650-750 °F. Additionally, the ABCR piping loop from the same sidecut draw line off of the column to P-1148/A to E-1111 is also carbon steel and operates at the same temperatures, rendering the ABCR piping system to E-1111 susceptible to hot H2S corrosion as well.
>
> Recommendation
>
> Replace the existing #4 sidecut piping noted above from C-1100 through P-1149/A to E1113 and P-1148/A to E-1111 (approximately 700’[feet] of 12”, 10”, 8” and 6”piping, plus some 4”and 3” at the P-1149/P-1148 suction/discharge headers). Upgrade the pipe material from carbon steel to 5 chrome.

To implement this recommendation, Chevron initiated an MOC in 2006 to replace the piping during the 2007 Turnaround. However, the MOC supporting documents had a narrowed scope to only replace the section of piping from P-1149/A pumps to the E-1113 heat exchanger because Chevron reduced the work scope during the 2007 turnaround planning process. The Description of Change in the MOC stated:

> Existing line is carbon steel in a hot service that operates in the range where high temperature sulfadation [sic] occurs. The line has been ut[i] inspected and found to be nearing tmin[ii] requiring replacement. Due to the higher temperature 9CR [9-Chrome] would be the prefered [sic] material.

Contradicting this Description of Change detailing a replacement of the entire 4-sidecut piping circuit, the MOC Summary Review and attached documentation only authorized replacement of the piping from the P-1149’s to E-1113. The MOC states:

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[i] UT is an abbreviation used to indicate ultrasonic thickness testing inspection technique.

[ii] Tmin is an abbreviation used to indicate minimum required piping wall thickness.

> 4 S/C piping has been operating hotter in recent years. The hotter temperatures 550 °F are in the high temperature sulfadation [sic] range. Additionally the section of 4 S/C piping from P-1149' s to E-1113 has been found to be nearing tmin.
>
> The section of pipng [sic] from P-1149's to E-1113 will be replaced with 9 Cr [9-Chrome] piping.

As a result, the portion of the piping containing the 52-inch component that failed on August 6th remained in service. Although the recommendation was intended to more broadly apply inherently safer materials of construction, the final implementation by the MOC limited the application of this more corrosion resistant metallurgy.[i] Again, the inherently safer, more corrosion resistant, metallurgy was not implemented more broadly in crude unit high temperature service. Other examples are discussed above in the section entitled *Chevron Sulfidation Corrosion Inspection and Mitigation*.

59. In 2007, the Chevron Richmond Refinery conducted training to teach employees about the importance of complying with the City of Richmond's Industrial Safety Ordinance (RISO)[ii] inherent safety guidance. The training states "we should always strive to implement inherently safer strategies to the greatest extent feasible." However, Chevron did not regularly or rigorously[iii] apply inherently safer design strategies in opportunities including PHAs, MOCs, incident investigation recommendations, and during turnarounds.[iv]

60. Chevron uses an inherently safer design checklist[v] for PHAs to meet inherently safer systems analysis requirements of the RISO. The checklist, provided by Contra Costa County, is intended to aid identification of opportunities to implement inherently safer design during the PHA process. The checklist was intended to stimulate discussion and analysis of potential opportunities to implement inherently safer design. Contra Costa County's guidance on the IST checklist states that some items may need to be reviewed by a team that is outside the PHA team in order to involve people with the required expertise. Chevron utilized the Contra Costa County inherently safer technologies checklist (IST Checklist) during the 2009 crude unit PHA.

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[i] As discussed earlier, only the section of piping downstream of the pumps was replaced with 9-Chrome.

[ii] The RISO will be discussed in more detail in the *Regulatory Oversight* section below.

[iii] Chevron does not utilize inherent safety guidewords or checklists during the MOC or incident investigation process. Inherently safer guidewords help direct the inherently safer review process. Examples of guidewords include minimization, substitution, moderation, and simplification. These words may be applied to materials, product inventory, process controls, process piping, and siting, among others. *See* Center for Chemical Process Safety (CCPS). "Inherently Safer Chemical Processes – A Life Cycle Approach." 2nd ed., Table 8.3, 2009.

[iv] As stated in the *Regulatory Oversight* section below, Chevron is only required to conduct inherently safer design strategies during PHAs and for the construction of new processes.

[v] Contra Costa County's guidance document entitled "Attachment C: Inherently Safer Systems Checklist" is provided as a tool for facilities to utilize during the PHA process. The actual use of the checklist is not required. *See* http://cchealth.org/hazmat/pdf/iso/attachment_c.pdf (accessed April 17, 2013).

However, only three permissively worded[i] inherently safer system recommendations were made, none of which addressed sulfidation corrosion or piping metallurgy. In addition, Chevron performed the checklist analysis using the same individuals who conducted the PHA despite Contra Costa County's guidance to involve other personnel with additional expertise. Performing a superficial analysis, Chevron failed to adequately consider inherently safer systems like improved metallurgy for corrosion resistance. For instance, the checklist prompted: "Use corrosion resistant material?" In response, Chevron stated that "vessel specifications and piping classifications include a conservative wall thickness and an appropriate corrosion allowance for each service." No mention is given to improving metallurgy to reduce corrosion. There is also no documented analysis regarding potential materials with enhanced corrosion resistance. There was no documentation of the inherently safer technologies analysis, and no inherently safer alternatives were documented. The checklist as applied by Chevron was a "check-the-box" exercise. Chevron Richmond PHAs were thus not an effective means of driving inherent safety. The table below gives a sample of the IST checklist questions along with the associated Chevron responses.[ii]

Contra Costa County Checklist Question	**Chevron IST Analysis**
Use Corrosion resistant materials?	Vessel specifications and piping classifications include a conservative wall thickness and an appropriate corrosion allowance for each service.
Use smallest diameter piping?	Piping sizes are the smallest possible for the capacity of the unit.
Substitute less hazardous raw materials?	Raw materials in use are of minimal hazard.
Dilute hazardous raw materials?	Raw materials currently dilute where applicable.
Minimize off-site impacts?	#4 Crude Unit is located at a distance from public areas.
Easy operation of valves designed to prevent inadvertent error?	In general, valves are arranged in a logical manner.
Increasing wall strength?	Piping classifications include a conservative wall thickness and an appropriate corrosion allowance for each service.

61. Contra Costa County inspected the Chevron Richmond Refinery in 2011, auditing Chevron's implementation of the county's inherently safer systems analysis requirements in the PHA process. The inspectors determined that Chevron's PHAs "follows the requirements specified by … ISS [inherent safety systems] guidelines." This approval by Contra Costa County

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[i] All began with "consider" and two began with "consider evaluating" which does not require any action by Chevron.

[ii] The comprehensive list of IST checklist questions and Chevron's corresponding answers are provided separately on the CSB website.

conveyed to Chevron that the regulator considered that Chevron's minimal analysis of opportunities to implement inherently safer design, its "check-the-box" exercise, was sufficient.

62. Effectively implementing inherently safer technology provides an opportunity for preventing major chemical incidents. The August 6, 2012, incident at Chevron and other incidents[43] throughout the refining industry highlight the difficulty in preventing failure caused by sulfidation corrosion in low silicon carbon steel piping solely through inspection, a procedural safeguard that is low on the hierarchy of controls. Using inherently safer design concepts to avoid issues such as variation in corrosion rate in carbon steel piping due to hard-to-determine silicon content will reduce future similar failures in refineries. Chevron and other process plants' implementation of inherently safer systems to the greatest extent feasible would provide a higher degree of protection from incidents like the one that occurred on August 6, 2012.

63. It is essential that MOCs incorporate hazard analyses and the assessment of opportunities to implement inherently safer systems. This process can be assisted through the use of guidewords to trigger the thought process. CCPS states that "by including inherent safety guidewords in a management of change program, the MOC protocol recognizes inherent safety as both a driving force for - and as an opportunity during - implementation."[44]

64. Layer of Protection Analysis (LOPA) is a well-recognized hazard analysis methodology that is intended to determine if a sufficient number of safeguards or layers of protection exist to protect against a particular hazard or accident scenario.[45] As the potential consequence of a particular scenario increases, the number of safeguards or protection layers must increase to reduce the risk of the scenario to what is considered an acceptable or tolerable level.[46] LOPA can be used to help an organization decide if the risk of a scenario or hazard has been reduced to a level that is "as low as reasonably practicable" (ALARP).[47] ALARP is a risk reduction goal, where risk reduction efforts are continued until the incremental effort to further reduce risk becomes grossly disproportionate to the level of additional risk reduction.[48] By rigorously reviewing accident or hazard scenarios, evaluating the potential consequence of the scenario, and identifying the safeguards or layers of protection necessary to drive risk to as low as reasonably practicable, LOPA becomes an effective organizational tool for implementing a Process Safety Management (PSM) mechanical integrity program.[49] LOPA also helps an organization decide which safeguards to focus on during operation, maintenance, and training.[i, 50] In addition, the LOPA methodology includes provisions allowing an organization to determine the availability[ii] and effectiveness of a safeguard or layer of protection in reducing the risk of a potential scenario.[51]

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[i] Chevron is a member of CCPS and peer-reviewed the CCPS LOPA publication. *See* Center for Chemical Process Safety (CCPS). "Layer of Protection Analysis – Simplified Process Risk Assessment," page xiv, 2001.

[ii] The probability that a system will be able to perform its designated function when required for use. Another term frequently used is *Probability of Failure on Demand* (PFD). Availability = 1 - PFD. *See* Center for Chemical Process Safety (CCPS), "Guidelines for Safe Automation of Chemical Processes," page XIX, 1993.

Regulatory Oversight

65. The Contra Costa County Industrial Safety Ordinance (ISO) requires that regulated facilities[i] within the county implement safety programs to prevent chemical incidents. Since the ISO took effect in January 1999, Contra Costa County has continued to make improvements to the implementation of the prevention program's elements.

66. The purpose of the ISO is to "prevent accidental release of hazardous chemicals; improve accident prevention by soliciting participation from industry and the community; require industry to submit a Safety Plan; and conduct audits of the plan and inspections of the industrial plants."[52]

67. Although the City of Richmond is located in Contra Costa County, the county does not have jurisdiction over industrial facilities located within the city limits. Thus, the ISO is not enforceable within the City of Richmond. On December 18, 2001, the City of Richmond adopted its own industrial safety ordinance (RISO), based on the ISO.[ii, 53] The RISO covers the two facilities located within the City of Richmond: Chevron and General Chemical West Richmond Works.[54] Pursuant to an agreement between the two parties, Contra Costa County inspects these two facilities and implements the RISO for the City of Richmond.[55]

68. The ISO and RISO contain identical provisions that address the use of inherent safety concepts. Each defines "inherently safer systems" as "feasible alternative equipment, processes, materials, lay-outs and procedures meant to eliminate, minimize, or reduce the risk of a major chemical accident or release by modifying a process rather than adding external layers of protection."[56] Both regulations also require that:

> For all covered processes, the stationary source shall consider the use of inherently safer systems in the development and analysis of mitigation items resulting from a process hazard analysis and in the design and review of new processes and facilities. The stationary source shall select and implement inherently safer systems to the greatest extent feasible. If a stationary source concludes that an inherently safer system is not feasible, the basis for this conclusion shall be documented in meaningful detail.[57]

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[i] The ISO applies to oil refineries and chemical plants within the county jurisdiction that are required to submit a Risk Management Plan to EPA and are program level 3 stationary sources as defined by the California Accidental Release Prevention (CalARP) Program. There are seven facilities covered by the ISO, five of which are refineries. *See* http://cchealth.org/hazmat/iso/ (accessed April 17, 2013).

[ii] At the time of the August 6th incident, the RISO did not include amendments made to the ISO in 2006. The 2006 amendments required an expansion of human factors programs, expanded management of organizational change reviews, security vulnerability analyses, and safety culture assessments. These amendments were subsequently adopted by the City of Richmond in February 2013. *See* http://cchealth.org/hazmat/iso/ (accessed on April 9, 2013).

69. The apparent intent of the ISO and RISO regulations is to require companies to evaluate their processes in order to identify opportunities to implement inherently safer systems. However, the plain language contained within these regulations conflicts with this intent. Both regulations contain the following permissive language: "the stationary source *shall consider* the use of inherently safer systems…"[58] This language does not require companies to conduct a comprehensive analysis and implement inherently safer systems even where feasible. It only requires such an analysis be considered. The regulations allow companies to merely engage in an activity contemplating the potential use of inherently safer systems.

70. The language within the ISO and RISO regulations also requires effective action to implement inherently safer systems "to the greatest extent feasible."[59] If an inherently safer system is not implemented, the regulations require that the basis for this decision be "documented in meaningful detail."[60] However, these regulations do not require documentation supporting the adequacy of existing "inherently safer"[61] claims. Chevron's compliance with the RISO is indicative of this deficiency. In its inherently safer systems checklist, Chevron simply concluded that its systems were inherently safer to the extent that no modifications were necessary. However, the company offered no documentation to substantiate these claims. Had the ISO and RISO regulations required analysis of inherently safer systems regardless of what the site already had in place, Chevron may have implemented the inherently safer recommendations made by technical staff to replace the 4-sidecut with an inherently safer metallurgy.

71. The inherently safer systems requirements of the ISO and RISO are only triggered by the conduct of a PHA or the construction of a new process.[62] Rebuilds, repairs, MOCs, and the implementation of incident investigation corrective actions do not require the analysis and application of inherently safer systems.

72. The Contra Costa County PHA guidance document presents four categories of risk reduction:[i] inherent, passive, active, and procedural (Figure 15).[ii] It states that all four categories should be used in the development of recommendations from process hazard analyses.[63] It reiterates the CCPS statement that all may contribute to the overall safety of a process, but that inherent safety is the most effective.[64] It goes on to state "The inherent and passive categories should be implemented when feasible for new processes and facilities and used during the review of Inherently Safer Systems for existing processes if these processes could cause incidents that could result in a Major Chemical Accident or Release."[65] This wording in the guidance

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[i] The guidance document uses CCPS definitions for the identified categories of risk reduction.

[ii] Inherent risk reduction involves eliminating the hazard by using materials and process conditions that are non-hazardous. Passive risk reduction is defined as minimizing the hazard through process and equipment design features that reduce the frequency or consequence of the hazard without active functioning of any device. Active risk reduction includes using controls, alarms, safety instrumented systems, and mitigation systems to detect and respond to process deviations from normal operation. Procedural risk reduction achieves the lowest level of risk reduction and involves using policies, operating procedures, training, administrative means, emergency response, and management approaches to prevent incidents and minimize the effects of an incident.

document demonstrates the importance Contra Costa County places on risk reduction and prevention such as metallurgy upgrades; however, as a guidance document, it is non-mandatory.

73. The California Division of Occupational Safety and Health (Cal/OSHA) has jurisdiction over employee safety in California.[66] Cal/OSHA is a division of the California Department of Industrial Relations and has operated a state plan industrial health and safety program since 1973 under a delegation from the U.S. Occupational Safety and Health Administration (OSHA). Cal/OSHA conducts inspections of California workplaces in response to industrial accidents, safety complaints, or as part of an inspection program targeting specific industries.[67] Consideration of inherently safer processes is not currently a required component of any Cal/OSHA (or federal OSHA) standard or regulation.[i]

74. The State of California has promulgated process safety regulations similar to OSHA[68] for the prevention or minimization of the consequences of the accidental release of acutely hazardous chemicals.[69] These regulations require that covered employers perform a PHA to identify, evaluate and control hazards involved in the process using recognized methodologies.[70]

75. California regulations, however, do not provide for a specific review of the effectiveness of the proposed safeguards to control the hazards identified in the PHA using recognized methodologies such as Layers of Protection Analysis (LOPA).[71] Additionally, California regulations do not have any requirements for the use of inherently safer systems analysis and the hierarchy of controls for establishing safeguards for identified process hazards. Cal/OSHA, like federal OSHA, also does not require damage mechanism hazard reviews as part of the PHA process.

76. The Energy Institute, an industry technical working group[ii] organized in the United Kingdom (UK), with contributions from regulators including the UK's Health and Safety Executive (HSE),[iii] as well as other entities,[iv] developed a document in 2008[v] that provides guidance on damage mechanism hazard reviews in the UK's offshore petrochemical industry. The guidance states that effective management of corrosion will contribute to equipment integrity and reduce risk from safety and environmental hazards.[72] In addition, during the design of a process, a corrosion review can be used to eliminate risks and achieve inherent safety.[73] The guidance also

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[i] This is also the case for US EPA Risk Management Program and the California Accidental Release Prevention Program regulations.

[ii] The Energy Institute is the leading chartered professional membership body supporting individuals and organizations across the energy industry. With a combined membership of over 13,500 individuals and 300 companies in 100 countries, it provides an independent focal point for the energy community and a powerful voice to engage business and industry, government, academia and the public internationally. *See* http://www.energyinst.org/about-us (accessed April 17, 2013).

[iii] HSE is an independent regulator that is tasked with securing the health, safety and welfare of workers within the UK. *See* http://www.hse.gov.uk/aboutus/index.htm (accessed April 17, 2013).

[iv] Chevron Energy Technology Company (ETC) was one of roughly 30 entities recognized in the guidance document as providing contributions to the institute that were "key to the development of this publication…". *See* http://www.energyinstpubs.org.uk/pdfs/815.pdf (accessed April 17, 2013).

[v] *Ibid.*

notes that damage mechanism hazard reviews should provide a structured framework for identifying risks associated with corrosion and developing suitable risk reduction measures.[74] These reviews should cover failure mechanisms including, but not limited to corrosion, environmental cracking, erosion, and mechanical damage, such as vibration induced fatigue.[75] Finally, this guidance states that a formal, documented quantitative and logic based assessment should be used when conducting corrosion reviews.[76]

77. Under a rule issued by the U.S. Environmental Protection Agency (EPA),[77] a facility with a tank, drum, pipe, or other process[i] that contains an extremely hazardous toxic or flammable substance listed at 40 CFR §68.130 in an amount above the "threshold quantity" specified for that substance, is required to conduct a hazard assessment as well as develop a prevention program and an emergency response program. These requirements are documented in a Risk Management Plan (RMP) that is submitted to EPA. Covered facilities must implement the RMP and update their RMPs periodically or when certain changes occur. The goal of EPA's Risk Management Program is to prevent accidental releases of substances that can cause serious harm to the public and the environment from short-term exposures, and to mitigate the severity of releases that do occur.[78]

78. The EPA RMP program provisions build on the planning and preparedness groundwork laid by the Emergency Planning and Community Right-to-Know Act of 1986 (EPCRA). EPCRA establishes requirements for federal, state, and local governments, as well as industry, regarding emergency planning and "Community Right-to-Know" reporting on hazardous toxic chemicals. EPCRA "help[s] increase the public's knowledge and access to information on chemicals at individual facilities, their uses, and releases into the environment."[79] According to the U.S. EPA's Chemical Emergency Preparedness and Prevention Office,[ii] transparency between industry and the public will improve community safety:

> Both EPCRA and the CAA [Clean Air Act] section 112(r) Risk Management Program encourage communication between facilities and the surrounding communities about chemical safety and chemical risks. Regulatory requirements, by themselves, will not guarantee safety from chemical accidents. Information about hazards in a community will allow local emergency officials and the public to work with industry to prevent accidents.[80]

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[i] "Process" means "any activity involving a regulated substance including any use, storage, manufacturing, handling, or on-site movement of such substances, or combination of these activities…" 40 CFR §68.3 (1997).

[ii] In 2004, the U.S. EPA's Chemical Emergency Preparedness and Prevention Office was merged with the Superfund Emergency Response Program and Oil Spill Prevention Program to form the Office of Emergency Management, or OEM. OEM works with other EPA partners, federal, state, and local agencies, and industry to prevent accidents and maintain and provide superb response capabilities. *See* http://www.epa.gov/oem/about.htm (accessed April 17, 2013).

The CCPS also notes that governments and advocacy organizations have been successful in driving performance improvement by using public disclosure to make safety information available to the public.[81]

79. Under the RMP program's hazard assessment requirement, a facility must prepare a worst-case release scenario analysis[82] and complete a five-year accident history.[83] A covered facility must also develop and implement an emergency response program that includes procedures for informing the public and local agencies about accidental releases and procedures and measures for emergency response after an accidental release.[84] Officials and the public, including local emergency planning committees (LEPCs) can use this information to understand the chemical hazards in the community and then work with industry to address and mitigate those hazards. With both EPCRA and the Risk Management Program, the regulatory purpose and substantive provisions emphasize the importance of transparency, sharing of process safety data, and public participation to prevent chemical accidents. The CSB notes that post-incident, during the decision-making related to piping repairs to the crude unit, the public, worker representatives, regulators, and governmental bodies played a key role driving transparency, accountability, and improved risk reduction.

80. Workforce involvement is a key element of process safety and effective chemical accident prevention. In the Center for Chemical Process Safety publication, *Guidelines for Risk Based Process Safety*, it lists workforce involvement as one of 20 essential management systems necessary to reduce process safety risks and prevent chemical accidents.[85] CCPS states that:

> …workers are potentially the most knowledgeable people with respect to the day-to-day details of operating the process and maintaining the equipment and facilities and may be the sole source for some types of knowledge gained through their unique experiences. Workforce involvement provides management a mechanism for tapping into this valuable expertise.[86]

This CCPS publication discusses general areas of workforce involvement in risk assessments, inspections, audits, and performance reviews. The CCPS notes that participation leads to empowerment, management responsiveness, and process safety performance improvement. [87] The OSHA PSM Standard emphasizes the importance of participation by workers and their representatives. It requires employers to develop a written plan of action, consult with employees, and make available all process safety information. [88] In previous investigation reports, the CSB has identified that workers and their representatives play a very important role in major incident prevention. For example, in the BP Texas City oil refinery investigation report, the CSB recommended that BP and the United Steelworkers International Union (USW) establish a joint program to report incidents and near misses, and to ensure that recommendations made during investigations were implemented. The CSB also recommended that API and the USW work together to develop a safety standard addressing leading and lagging process safety indicators. [i]

81. In July 2012, the CSB held a public hearing on process safety indicators[ii] to explore how companies and regulators use process safety metrics to manage risks and drive continuous safety improvements. During this hearing the CSB stated that, following the 2005 BP Texas City accident, both the CSB and Baker Panel[iii] reports noted the lack of focus by BP on process safety and inadequate performance measurement indicators. The CSB also noted that one goal of process safety indicators is to drive continuous process safety improvement, and that regulators can utilize these indicators to focus inspections, audits, and investigations.

82. Process safety management systems are critical for reducing process safety incidents. Process safety indicators are a significant element of these systems. Indicators measure the strengths and weaknesses of process safety management systems, to achieve and maintain safe and reliable operations. [89] Properly selected and managed indicators will identify the successes and point out the flaws of the system.[90]

83. In 2008, the CCPS published a guidance document for the development of leading[iv] and lagging[v] process safety indicators to assist industry in avoiding catastrophic chemical incidents.[91] While process safety indicators are an important tool for major accident prevention, the simple activity of identifying and recording process safety metrics will not drive process safety improvement. CCPS notes that these metrics must be "collected, analyzed, communicated, understood, and *acted upon.*"[92]

84. The UK HSE has published a guidance document to help chemical and major hazard industries develop process safety indicators. HSE states that:

> Most systems and procedures deteriorate over time, and system failures discovered following a major incident frequently surprise senior managers, who sincerely believed that the controls were functioning as designed. Used effectively, process

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[i] Process safety indicators are also referred to as safety performance indicators, metrics, key process indicators (KPI), performance measures, indicators, etc…

[ii] *See* http://www.csb.gov/assets/1/19/CSB_20Public_20Hearing.pdf (accessed April 17, 2013).

[iii] *See* http://www.bp.com/liveassets/bp_internet/globalbp/globalbp_uk_english/SP/STAGING/local_assets/assets/pdfs/Baker_panel_report.pdf (accessed April 12, 2013).

[iv] Leading indicators are measurements that predict future performance to ensure that safety protection layers and operating discipline are being maintained, including unsafe behaviors or insufficient operating discipline equipment selection, engineering design, specification of inspection frequency, and technique. *See* Center for Chemical Process Safety (CCPS), *Guidelines for Process Safety Metrics*, Page 20. 2010.

[v] Lagging indicators are facts about previous events, such as process safety incidents, that meet the threshold of severity and should be reported as part of the process safety metric. *See* Center for Chemical Process Safety (CCPS), "Guidelines for Process Safety Metrics," 2010; Page 20.

> safety indicators can provide an early warning, before catastrophic failure, that critical controls have deteriorated to an unacceptable level. [93]

85. The public can play an important role in monitoring safety management systems. In its recent guidelines, the CCPS promoted the sharing of process safety indicators with the public:

> Sharing performance metrics and results broadly can engage the public as a partner in holding the organization accountable for process safety performance. Making metrics and performance public can be an especially powerful way of maintaining upper management commitment since it will likely be the CEO or other senior managers who will be called to account by the public if goals are not met or performance declines. Communicating process safety successes also demonstrates to employees and the public that positive change can be, and are being, made within an organization. [94]

Recommendations

Under 42 U.S.C. 7412(r)(6)(C)(ii), the U.S. Chemical Safety and Hazard Investigation Board is charged with “recommending measures to reduce the likelihood or the consequences of incidental releases and proposing corrective steps to make chemical production, processing, handling and storage as safe and free from risk of injury as possible ….” The CSB makes recommendations based on the findings and conclusions of the investigation. Recommendations are made to parties that can affect change to prevent future incidents, which may include the company, contractors, industry organizations responsible for developing good practice guidelines, regulatory bodies, and/or organizations that have the ability to broadly communicate lessons learned from the incident, such as trade associations or professional societies.

Chevron U.S.A (Urgent)

2012-03-I-CA-R1

At all Chevron U.S. refineries, engage a diverse team of qualified personnel to perform a documented damage mechanism hazard review. This review shall be an integral part of the Process Hazard Analysis cycle and shall be conducted on all PSM-covered process piping circuits and process equipment. The damage mechanism hazard review shall identify potential process damage mechanisms and consequences of failure, and shall ensure safeguards are in place to control hazards presented by those damage mechanisms. Analyze and incorporate into this review applicable industry best practices, Chevron Energy Technology Company findings and recommendations, and inherently safer systems to the greatest extent feasible.

2012-03-I-CA-R2

At all California Chevron U.S. refineries, report leading and lagging process safety indicators, such as the action item completion status of recommendations from damage mechanism hazard reviews, to the federal, state, and local regulatory agencies that have chemical release prevention authority.

Mayor and City Council,
City of Richmond, California

2012-03-I-CA-R3

Revise the Industrial Safety Ordinance (ISO) to require that Process Hazard Analyses include documentation of the recognized methodologies, rationale and conclusions used to claim that safeguards intended to control hazards will be effective. This process shall use established qualitative, quantitative, and/or semi-quantitative methods such as Layers of Protection Analysis (LOPA).

2012-03-I-CA-R4

Revise the Industrial Safety Ordinance (ISO) to require the documented use of inherently safer systems analysis and the hierarchy of controls to the greatest extent feasible in establishing safeguards for identified process hazards. The goal shall be to drive the risk of major accidents to As Low As Reasonably Practicable (ALARP). Include requirements for inherently safer systems analysis to be automatically triggered for all Management of Change and Process Hazard Analysis reviews, prior to the construction of new processes, process unit rebuilds, significant process repairs, and in the development of corrective actions from incident investigation recommendations.

2012-03-I-CA-R5

Ensure the effective implementation of the damage mechanism hazard review program (2012-03-I-CA-R1 and 2012-03-I-CA-R2), so that all necessary mechanical integrity work at the Chevron Richmond Refinery is identified and recommendations are completed in a timely way.

Board of Supervisors
Contra Costa County, California

2012-03-I-CA-R6

Revise the Industrial Safety Ordinance (ISO) to require that Process Hazard Analyses include documentation of the recognized methodologies, rationale and conclusions used to claim that safeguards intended to control hazards will be effective. This process shall use established qualitative, quantitative, and/or semi-quantitative methods such as Layers of Protection Analysis (LOPA).

2012-03-I-CA-R7

Revise the Industrial Safety Ordinance (ISO) to require the documented use of inherently safer systems analysis and the hierarchy of controls to the greatest extent feasible in establishing safeguards for identified process hazards. The goal shall be to drive the risk of major accidents to As Low As Reasonably Practicable (ALARP). Include requirements for inherently safer systems analysis to be automatically triggered for all Management of Change and Process Hazard Analysis reviews, prior to the construction of new processes, process unit rebuilds, significant process repairs, and in the development of corrective actions from incident investigation recommendations.

2012-03-I-CA-R8

Monitor and confirm the effective implementation of the damage mechanism hazard review program (2012-03-I-CA-R1 and 2012-03-I-CA-R2), so that all necessary mechanical integrity work at the Chevron Richmond Refinery is identified and recommendations are completed in a timely way.

California State Legislature,
Governor of California

2012-03-I-CA-R9

Revise the California Code of Regulations, Title 8, Section 5189, Process Safety Management of Acutely Hazardous Materials, to require improvements to mechanical integrity and process hazard analysis programs for all California oil refineries. These improvements shall include engaging a diverse team of qualified personnel to perform a documented damage mechanism hazard review. This review shall be an integral part of the Process Hazard Analysis cycle and shall be conducted on all PSM-covered process piping circuits and process equipment. The damage mechanism hazard review shall identify potential process damage mechanisms and consequences of failure, and shall ensure safeguards are in place to control hazards presented by those damage mechanisms. Require the analysis and incorporation of applicable industry best practices and inherently safety systems to the greatest extent feasible into this review.

2012-03-I-CA-R10

For all California oil refineries, identify and require the reporting of leading and lagging process safety indicators, such as the action item completion status of recommendations from damage mechanism hazard reviews, to state and local regulatory agencies that have chemical release prevention authority. These indicators shall be used to ensure that requirements described in 2012-03-I-CA-R9 are effective at improving mechanical integrity and process hazard analysis performance at all California oil refineries and preventing major chemical incidents.

2012-03-I-R11

Establish a multi-agency process safety regulatory program for all California oil refineries to improve the public accountability, transparency, and performance of chemical accident prevention and mechanical integrity programs. This program shall:

1. Establish a system to report to the regulator the recognized methodologies, findings, conclusions and corrective actions related to refinery mechanical integrity inspection and repair work arising from Process Hazard Analyses, California oil refinery turnarounds and maintenance-related shutdowns;
2. Require reporting of information such as damage mechanism hazard reviews, notice of upcoming maintenance-related shutdowns, records related to proposed and completed mechanical integrity work lists, and the technical rationale for any delay in work proposed but not yet completed;

3. Establish procedures for greater workforce and public participation including the public reporting of information; and
4. Provide mechanisms for federal, state and local agency operational coordination, sharing of data (including safety indicator data), and joint accident prevention activities. The California Department of Industrial Relations will be designated as the lead state agency for establishing a repository of joint investigative and inspection data, coordinating the sharing of data and joint accident prevention activities.

2012-03-I-CA-R12

Require that Process Hazard Analyses required under California Code of Regulations, Title 8, Section 5189 Section (e) include documentation of the recognized methodologies, rationale and conclusions used to claim that safeguards intended to control hazards will be effective. This process shall use established qualitative, quantitative, and/or semi-quantitative methods such as Layers of Protection Analysis (LOPA).

2012-03-I-CA-R13

Require the documented use of inherently safer systems analysis and the hierarchy of controls to the greatest extent feasible in establishing safeguards for identified process hazards. The goal shall be to drive the risk of major accidents to As Low As Reasonably Practicable (ALARP). Include requirements for inherently safer systems analysis to be automatically triggered for all Management of Change and Process Hazard Analysis reviews, prior to the construction of new process, process unit rebuilds, significant process repairs and in the development of corrective actions from incident investigation recommendations.

2012-03-I-CA-R14

Monitor and confirm the effective implementation of the damage mechanism hazard review program (2012-03-I-CA-R9 and 2012-03-I-CA-R10), so that all necessary mechanical integrity work at all California Chevron Refineries is identified and recommendations are completed in a timely way.

The U.S. Environmental Protection Agency

2012-03-I-CA-R15

Jointly plan and conduct inspections with Cal/OSHA, California EPA and other state and local regulatory agencies with chemical accident prevention responsibilities to monitor the effective implementation of the damage mechanism hazard review and disclosure requirements under 2012-03-I-CA-R9 and R10 above.

The Board of Supervisors, Contra Costa County, California, 2012-03-I-CA-R16;
The Mayor and City Council, City of Richmond, California, 2012-03-I-CA-R17;
The California Air Quality Management Divisions, 2012-03-I-CA-R18;
The U.S. Environmental Protection Agency, 2012-03-I-CA-R19; and
The California Environmental Protection Agency, 2012-03-I-CA-R20;

Participate in the joint regulatory program described in recommendation 2012-03-I-CA-R11. This participation shall include contributing relevant data to the repository of investigation and inspection data created by the California Department of Industrial Relations and jointly coordinating activities.

Additional Issues Currently Under Investigation

The following section highlights additional issues which the CSB has identified to date in its investigation of the Chevron Richmond Refinery fire and major hydrocarbon release that occurred on August 6, 2012. These issues relate to the ongoing CSB investigation of the management and regulation of health and safety at refineries. The CSB final report will make additional recommendations consistent with this interim report and will present additional detailed findings and analyses in a final report on the incident, to be released later in 2013.

Regulatory Oversight

The CSB noted in its BP Texas City (BPTC) Final Investigation Report (issued in March 2007) the importance of having a well-resourced, competent regulator consisting of individuals with the necessary training, education, and experience to conduct planned comprehensive and robust inspections of facilities with the goal of preventing catastrophic accidents. In a 1992 compliance directive[i] the federal Occupational Safety and Health Administration (OSHA) stated that the primary enforcement model for the Process Safety Management of Highly Hazardous Chemicals (PSM) standard would be planned, comprehensive, and resource-intensive Program Quality Verification (PQV) inspections to help prevent catastrophic accidents.[95] However, the CSB report noted that for the 10-year period prior to the Texas City incident, federal OSHA had conducted no planned PQV inspections in oil refineries. Regular planned inspections appropriately emphasize the prevention of accidents that are potentially catastrophic. Issuing fines and prosecuting companies post-incident are not acceptable substitutes for prevention. As a result, CSB recommended in its report that OSHA strengthen the planned enforcement of the OSHA Process Safety Management (PSM) standard by developing more highly trained and experienced inspectors to conduct more comprehensive inspections similar to those under OSHA's PQV program at facilities presenting the greatest risk of a catastrophic accident.

Spurred in part by the CSB's recommendations, OSHA issued the Petroleum Refinery Process Safety Management National Emphasis Program (NEP) on June 7, 2007.[ii] The NEP was a federal program that established guidelines for inspecting petroleum refineries to assure compliance with the PSM standard, 29 CFR §1910.119.[96] Unlike the PQV approach to inspections, which "employs a broad, open-ended inspection strategy and uses a more global approach to identify compliance deficiencies…,"[97] the NEP "provide[d] a specific tool to evaluate compliance with the [PSM] standard…[which] identifies a particular set of requirements from the PSM standard from which CSHOs [Compliance Safety and Health Officers] are to review documents, interview employees, and verify implementation for specific processes, equipment, and procedures."[98] While the CSB called for an ongoing comprehensive inspection

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[i] Compliance directives are the main method OSHA uses to communicate plans, inspection methods, and compliance expectations to their Compliance Safety and Health Officers (CSHOs) for enforcing a new regulation.

[ii] Originally Directive Number CPL 03-00-004. Extended August 18, 2099 as Directive Number CPL 03-00-010 to allow more time to complete NEP inspections under the original CPL 03-00-004.

program, inspections being conducted pursuant to the NEP were terminated in 2011. The CSB recommendation to OSHA remains Open.[i]

OSHA State Plan States[ii] were strongly encouraged but not required to implement the NEP. California's Division of Occupational Safety and Health (Cal/OSHA) did not adopt the NEP "because of its dedicated PSM Unit."[99] Cal/OSHA informed the CSB that federal OSHA approved this decision in 2007. In lieu of conducting NEP inspections, Cal/OSHA's PSM Unit has conducted and continues to conduct a full range of programmed, accident, complaint, and referral inspections of PSM-covered facilities in the state of California pursuant to the California Labor Code, Title 8 regulations, and Cal/OSHA's Policy and Procedures (P&P) Manual C-17 "Process Safety Management,"[iii] to ensure these facilities are complying with PSM requirements.

Between 2006 and August 6, 2012, Cal/OSHA conducted three planned inspections of the Chevron Richmond facility, totaling only 150 inspector hours of effort. None of these inspections resulted in citations or fines. In contrast, according to statistics provided by OSHA, federal NEP refinery inspections conducted between 2007 and the end of 2011 lasted roughly 1,000 inspector hours each and resulted in an average of 11.2 violations and $76,821 in penalties per inspection. OSHA noted that hours spent on a typical federal refinery NEP inspection were 40 times greater than the average OSHA inspection. These numbers indicate a major disparity in thoroughness and comprehensiveness between the planned inspections conducted by Cal/OSHA and the NEP inspections conducted by OSHA and other OSHA State Plan States.

The safety case is a rigorous prescriptive and goal-setting regulatory regime that is highlighted by its adaptability and requirements for continuous improvements in risk reduction for high hazard industrial facilities. The approach is used widely overseas but is not used currently for U.S. process industries. The CSB is currently examining whether the implementation of the safety case regime could be a more effective regulatory tool for Cal/OSHA in its effort to ensure that California refineries are identifying and controlling hazards and ultimately driving risk to as low as reasonably practicable (ALARP). Utilizing the safety case requires effective implementation by an independent, competent, well-funded regulator. Experience and competence of the regulator in technical areas such as chemical engineering, human factors, and process safety are necessary to provide effective auditing and regulatory oversight for prevention. To ensure effective implementation of the safety case, industry standards and guidelines must be rigorous and up-to-date as well. The CSB notes that relevant and applicable industry standards and guidelines – such as API RP 939-C – currently contain voluntary and permissive language. The CSB will be examining the need for more effective good practice standards and guidelines containing the necessary requirements to prevent catastrophic accidents.

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[i] Open - Awaiting Response or Evaluation/Approval of Response (O - ARE/AR) - The recipient has not submitted a substantive response, or the evaluation by CSB staff of a response is pending, or the Board has not yet acted on staff recommendation of status.

[ii] Section 18 of the Occupational Safety and Health Act of 1970 encourages States to develop and operate their own job safety and health programs, referred to informally as an OSHA State Plan. OSHA approves and monitors State plans and provides up to 50 percent of an approved plan's operating costs.

[iii] Issued June 6, 1994. Revised August 1, 1994 and May 19, 2007.

In addition to the issues discussed above, the CSB will also be examining the need for the reporting of leading and lagging process safety indicators to the regulator; the regulator's effective use of these process safety indicators; workforce and stakeholder involvement in regulatory oversight of refineries; and the thoroughness of Contra Costa County's safety auditing of the Chevron facility.

Emergency Planning and Reporting

According to information provided by Contra Costa Emergency Medical Services, 15,213 individuals sought emergency medical attention between August 6 and August 23, 2012, due to the Chevron refinery major hydrocarbon release and fire.

CSB Investigation Team members visited local hospitals the week of the incident to better understand the impact on the surrounding community. Officials at Doctor's Medical Center (DMC) in San Pablo, California, informed the CSB that in the days following the incident they were inundated with emergency room visits and found it difficult to handle the influx due to a lack of funding and staffing. Officials at both DMC and Kaiser Permanente Hospital (KP) in Richmond told the CSB that they lacked specific knowledge of the chemicals released as a result of the incident, complicating efforts to evaluate and treat individuals.

The California Code of Regulations (CCR) requires that owners and operators of hazardous waste facilities make "arrangements to familiarize local hospitals with the properties of hazardous waste handled at the facility and the types of injuries or illnesses which could results from fires, explosions, or releases at the facility."[100] The CSB is currently evaluating ways to ensure that hospitals have the information necessary to properly evaluate and treat individuals that may be exposed to releases from facilities in Contra Costa County.

Following the incident, Contra Costa County's Community Warning System (CWS) notified the surrounding community of a hazardous material incident and ordered a shelter-in-place (SIP). The CWS uses sirens, the news media, and phone calls to residents in order to initiate the SIP. Contra Costa County issued the SIP on August 6, 2012, at 6:38 pm for the cities of Richmond, San Pablo, and North Richmond, California, and lifted the SIP later that evening at 11:12 pm. However, the CSB has learned that some phone calls notifying residents of the SIP did not occur until over four hours after the release.

It is essential that responders, community residents, and hospitals in the areas surrounding industrial facilities be aware of what hazardous materials exist at these facilities, what specific chemicals are released into the community in the event of an incident, and what is known about the potential acute and chronic health impacts. The CSB will be analyzing ways to strengthen current regulations and policies to ensure there is proper emergency planning and reporting for industrial facilities in Contra Costa County and the state of California.

Emergency Response

OSHA provides guidance on emergency response in its *Hazardous Waste Operations and Emergency Response* standard, known as HAZWOPER, under 29 CFR §1910.120 (p) and (q). Under 29 CFR §1910.120(q)(6), the HAZWOPER standard contains requirements for training and qualification of all individuals involved in emergency response related to their roles and responsibilities.

Good safety practice dictates that individuals responding to emergencies should have the technical knowledge to give input into shutdown decisions, set up an incident command structure, establish boundary limits, and evaluate the "hot zone." Access to the hot zone must be strictly limited to personnel with higher degrees of specific training, experience, and appropriate personal protective equipment; all others must be removed to a safe location away from chemical hazards. Hot zone boundaries must be established to anticipate the possible escalation of releases and the positioning of firefighting equipment such as fire trucks.

The CSB will be looking at the sufficiency of regulatory requirements, industry standards, and good practices, in addition to evaluating emergency response decision-making following the leak and subsequent pipe rupture (including the training and qualification of responders) to determine whether improvements are needed in these areas.

Safety Culture

The Center for Chemical Process Safety (CCPS) defines process safety culture as the "combination of group values and behaviors that determines the manner in which process safety is managed."[101] As the CSB noted in its BP Texas City Report, safety culture can be influenced by management changes, historical events, and economic pressures. After reviewing evidence and decisions made relating to materials of construction and mechanical integrity within the crude unit at the Chevron refinery, as well as the response to the leak on August 6, 2012, the CSB has determined that issues relating to safety culture are relevant to this incident. The CSB will examine the Chevron Richmond Refinery's approach to safety, its safety culture and any organizational deficiencies, to determine how to best prevent future incidents.

The CSB notes that on August 6, 2012, following discovery of the leak on the 4-sidecut piping, Chevron hoped to forestall a shutdown by installing a leak repair clamp.[i] Chevron's mechanical integrity management system has not been fully successful in detecting and replacing deteriorated piping components prior to failure, resulting in the company's frequent use of leak repair clamps[ii] to externally stop process fluid leaks. Chevron's reliance on such clamps to mitigate process piping component leaks identifies serious questions about its mechanical integrity program. The CSB determined that Chevron

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[i] Chevron's leak repair clamp vendor was called out to the scene of the leak to help determine potential clamping options.

[ii] Leak repair clamps are mechanical devices designed and installed to stop a leak from a piping component such as piping, valves, flanges, and instrumentation. These devices are typically intended to provide a temporary repair while a process continues operation until a plant shutdown takes place and a permanent repair can be made.

has more than 100 clamps on hydrocarbon and other process piping components at the Richmond refinery. The leak repair clamp is typically relied upon to prevent further leaking until the next unit turnaround, when the deteriorated piping component can be repaired. However, Cal/OSHA citations following the August 6, 2012, fire in the crude unit identified that Chevron has not always replaced these clamps during unit turnarounds and these devices then remain in service significantly longer than originally intended. The CSB determined that Chevron has leak repair clamps in place on piping components containing hazardous flammable process fluids including applications where the process material is above the autoignition temperature. Some of these leak repair clamp applications are in locations where a permanent repair would not have required a unit shutdown. The CSB will further evaluate the frequent use of leak repair clamps by Chevron and the potential that the deviance of a weak mechanical integrity management system has been normalized.[i]

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[i] Normalization of deviance is a long-term phenomenon in which individuals or work teams gradually accept a lower standard of performance until the lower standard becomes the norm. It is typically the result of conditions slowly changing and eroding over time. *See* Center for Chemical Process Safety (CCPS), Recognizing Catastrophic Incident Warning Signs in the Process Industries, Page 4. 2012.

BY THE

U.S. Chemical Safety and Hazard Investigation Board

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Chair

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Member

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Member

Date of Approval April __, 2013.

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Exhibit J

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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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TABLE OF CONTENTS

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

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[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° 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

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[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.

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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^{o} 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

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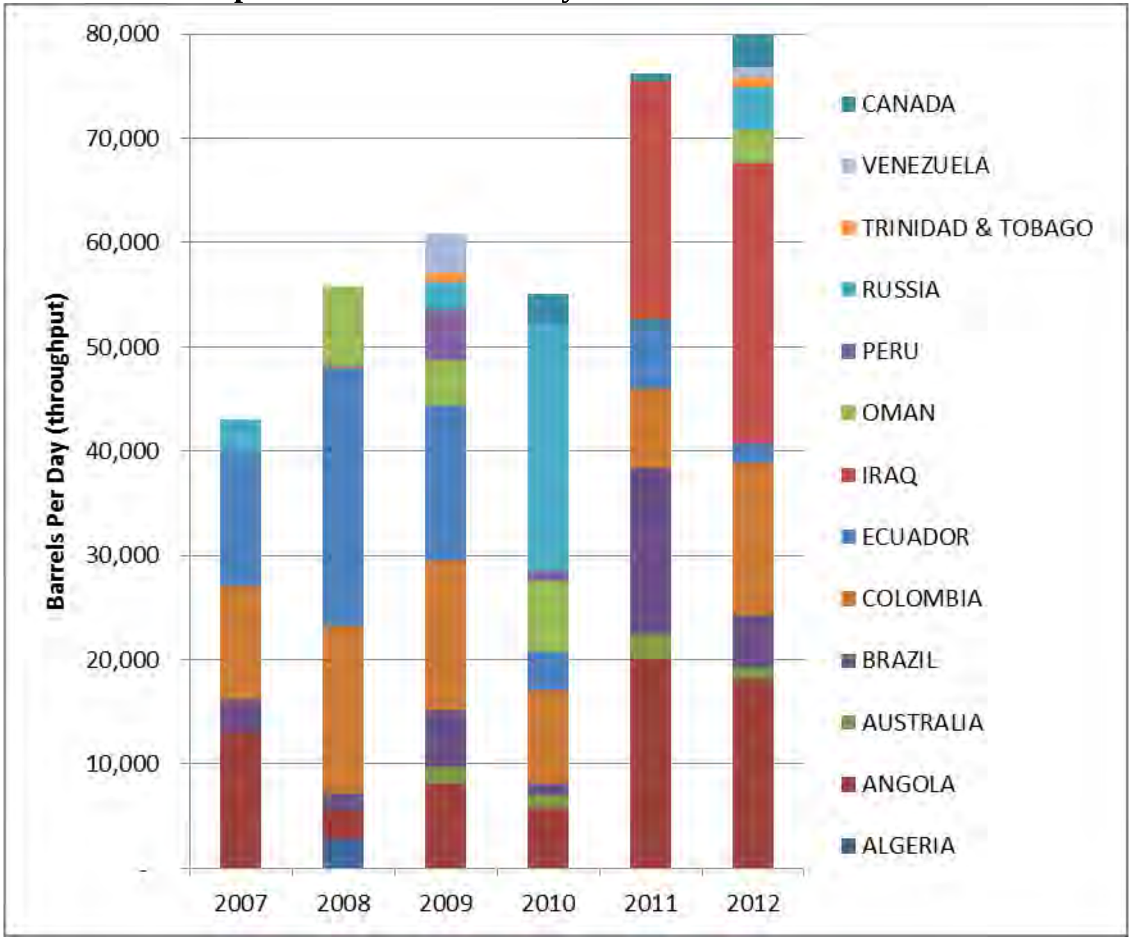
[23] John R. Auers and John Mayes, North American Production Boom Pushes Crude Blending, Oil & Gas Journal, May 6, 2013, Available at: http://www.ogj.com/articles/print/volume-111/issue-5/processing/north-american-production-boom-pushes.html.

[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.

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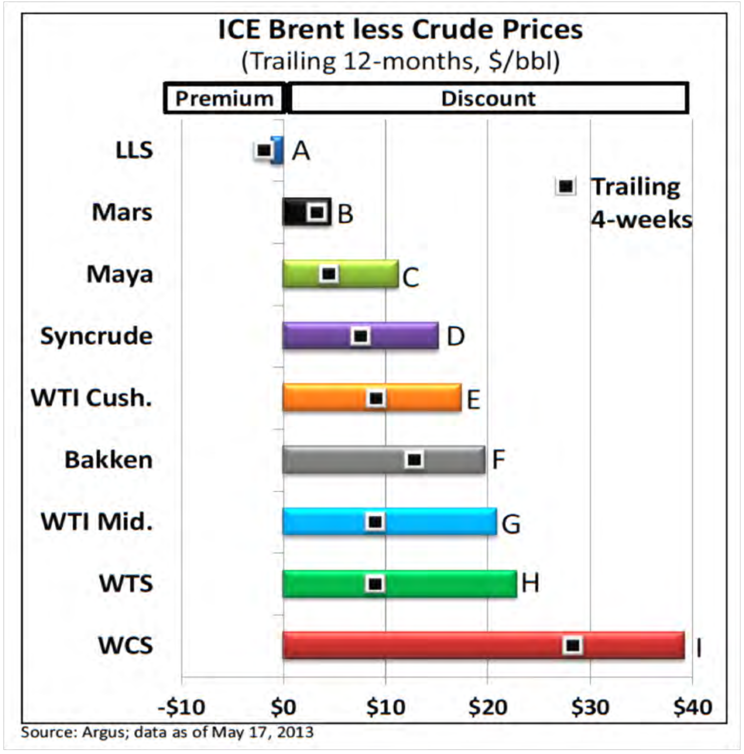
[26] Valero, UBS Global Oil and Gas Conference, May 21-22, 2013, p. 10, Available at: http://www.valero.com/InvestorRelations/Pages/EventsPresentations.aspx. provided as Appendix D to TGG Comments.

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



Source: Argus; data as of May 17, 2013

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

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[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.

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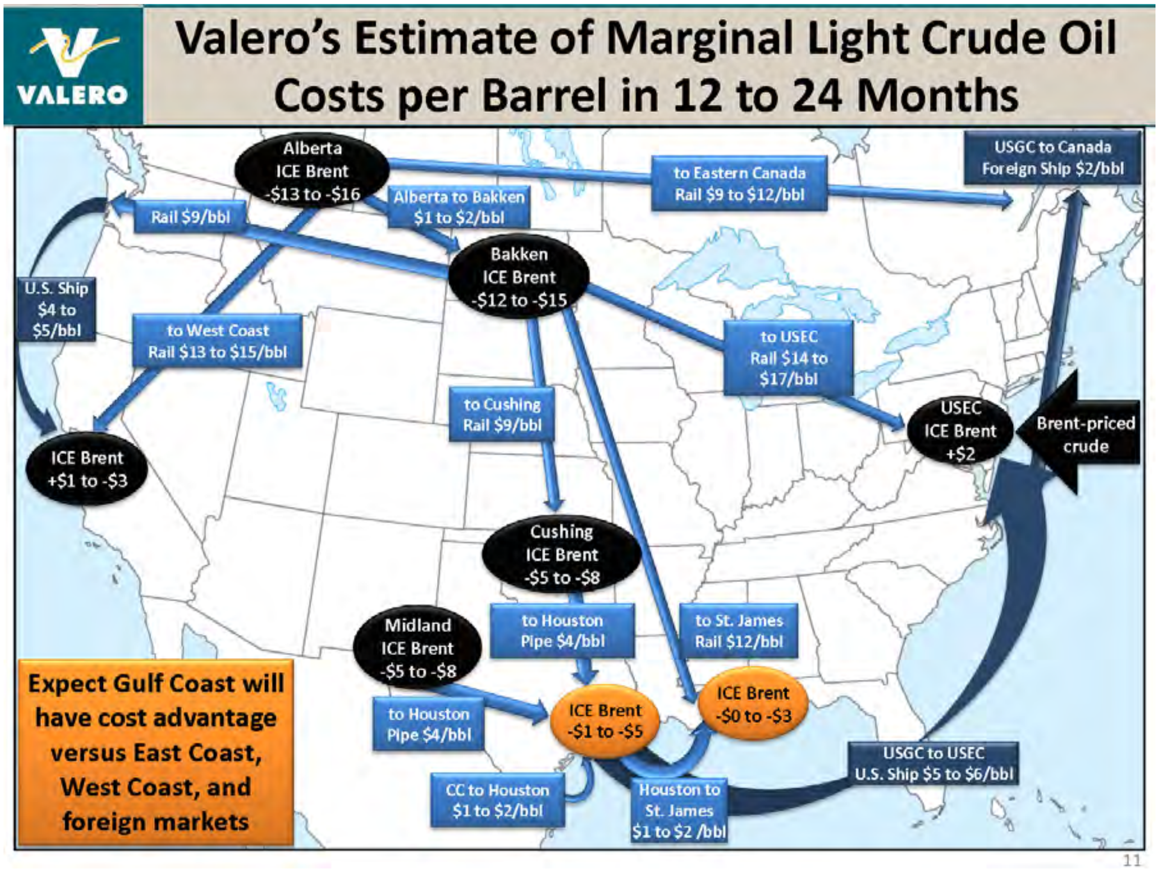
[31] Brent crude is a major trading classification of sweet light crude oil sourced from the North Sea. Brent is the leading global price benchmark for Atlantic basin crude oils and is used to price two thirds of the world's internationally traded crude oil supplies. It contains about 0.37% sulfur and 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]

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[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.

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[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

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[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

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[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:

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[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.

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[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.

Exhibit K

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MIDWEST ENERGY NEWS

Bakken crude makeup faces scrutiny in rail car explosion

Posted on 09/10/2013 by EnergyWire

By Elana Schor

(Photo by Russ Allison Loar via Creative Commons)

As U.S. regulators and Canadian investigators home in on the calamitous July derailment of a 73-car oil train in Quebec, one question lingers, fraught with consequences for crude shippers: Did the contents of the rail cars fuel the disaster's intense explosion and fire?

If the Bakken crude that slammed into the small town of Lac-Mégantic is linked to the severity of the resulting damage, the shale oil boom could face stricter transportation regulations and the public-relations black eye of a tie to the crash that killed at least 47 people. But some experts in oil production and transportation see little out of the ordinary about the ignition of crude not treated as explosive, given the friction and speed of the freight train that jumped the tracks.

"Oil, even at very low pressures … still has some natural gas dissolved in it, and that gas will try to form a gaseous state every time there's a pressure drop," University of Texas, Austin, petroleum engineering professor Paul Bommer said in an interview.

Loading the ill-fated crude into tank cars that rode the Montreal, Maine and Atlantic Railway Ltd. to Lac-Mégantic likely caused a small pressure drop, Bommer added, leaving room for "a fairly minor gaseous phase" to remain. "And gas, we all know, is extremely combustible."

The Federal Railroad Administration warned the oil industry three weeks after the derailment that it had concerns about widespread misclassification of crude on the tracks as well as the potential for chemicals used in hydraulic fracturing to corrode rail cars used for shipping oil.

The agency's "Bakken blitz" investigation into crude shipments, set against the slower-moving process of tightening rules for train operators, is setting the stage for an oil-versus-rail battle over which sector bears primary responsibility for preventing future accidents (*EnergyWire*, Sept. 3).

Pipeline and Hazardous Materials Safety Administration chief Cynthia Quarterman emphasized the classification aspects of the "blitz" in a Wednesday blog post that described her agency and FRA as "laser focused on the energy boom epicenter" of the Bakken.

"Today, our railways move more hazardous materials than ever before," Quarterman wrote on the Transportation Department's website. "DOT will continue to enforce safety regulations — and revise them if necessary — to protect our communities and the environment."

Among PHMSA's nine classes of hazardous materials, "most forms" of crude fall under Class 3, FRA wrote in a recent emergency order that called on rail operators to develop plans for more reliably securing parked trains to the tracks. Class 3 materials can belong to one of three so-called packing groups under federal regulations, depending on their flashpoints, or the lowest temperatures required to create the potential for ignitable vapors.

The oil that spilled in Lac-Mégantic "was shipped as a Class 3, Packing Group 3 flammable liquid," the lead Canadian investigator of the disaster told Reuters last month.

It remains unclear, however, whether shipping the Bakken crude as a higher packing group would have changed the handling standards used by the now-bankrupt railroad at the center of the disaster. Class 2 is typically reserved for gases, and even more highly flammable liquids such as gasoline remain in Class 3.

"I wouldn't be any more concerned about a tank of Bakken oil versus a tank of gasoline," University of North Dakota Energy & Environmental Research Center Associate Director John Harju said in an interview, though he affirmed that "Bakken oil is more volatile than heavy crude" and likened its handling to some of the lighter, liquid condensate produced alongside natural gas.

Mohamed Soliman, chairman of the petroleum engineering department at Texas Tech University and a former longtime employee at Halliburton Co., echoed that assessment. "Shale requires better handling than crude oil that is very heavy because it burns easier," he said in an interview.

Souring on hydrogen sulfide

Shale oil's light nature can stem in part from the higher proportion of natural gas hydrocarbons such as pentane, butane and ethane that are often produced during its extraction from underground rock formations. These condensate liquids, which fetch their own price on the market, are extracted to some degree during the separation process that shale oil undergoes before shipment, but their presence could have left a mark on the resulting product that provided the spark needed to burst into quick flame in Quebec.

It is this possible "natural gas dissolved" in the oil at issue that Bommer linked to the volatile nature of the Lac-Mégantic explosion. The prospect that hydrogen sulfide might have played a role in the fires, however, was met with dismissal from Bommer and Harju, who co-authored a 2011 study for the Society of Petroleum Engineers that traced a brief uptick in the sulfurous "souring" of Bakken reservoirs to insufficient fluid disinfection at well sites.

"Looking at Bakken crude as somehow the cause or some extremely different factor in severity of this fire and so on, I think, is silly," Harju said, also a member of the group that advises the Department of Energy on unconventional fossil-fuel technology.

"It was a tragic accident that points more at rail handling than at the contents of the cars. If it was gasoline, they wouldn't be asking, 'Was this a special type of gasoline?'"

This entry was posted in **News** and tagged **North Dakota**, **oil** by **EnergyWire**. Bookmark the **permalink [http://www.midwestenergynews.com/2013/09/10/bakken-crude-makeup-faces-scrutiny-in-rail-car-explosion/]** .

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Exhibit L

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Federal Agencies to Review Hazmat Rail Rules

Wednesday, July 31, 2013

Michaud, Pingree meet with Pipeline and Hazardous Materials Safety Administration

WASHINGTON, DC – Today, Representatives Mike Michaud and Chellie Pingree met with Cynthia Quarterman, the Administrator of the Pipeline and Hazardous Materials Safety Administration (PHMSA). In addition to PHMSA, Michaud and Pingree have also met with the National Transportation Safety Board (NTSB) and the Federal Railroad Administration (FRA) following their request for a safety review earlier this month in the wake of the Lac-Megantic rail accident.

After hearing the serious safety concerns raised by the NTSB over DOT-111 tanker cars, which were among the ruptured cars in the Quebec tragedy, Michaud and Pingree encouraged PHMSA to issue a new rule enhancing the design of these cars as soon as possible.

"After the accident in Quebec, there have been a number of safety concerns raised—both specifically in response to it and others that are longstanding. While it is still too early in the investigation to determine exactly how this tragedy could have been prevented, the design flaws of DOT-111 tank cars are well documented. We appreciate the Pipeline and Hazardous Materials Safety Administration's efforts to advance a rule to update the design of these cars, but progress is frustratingly slow given the initial delay. The federal rulemaking process is a cumbersome one, but we need to avoid any further delays, especially given the exponential growth of hazardous material shipments. Whether its oil, ethanol, or some other hazardous material travelling on our nation's tracks, the American people deserve to know that these shipments are being carried in tanker cars that are designed to the highest safety standards," said Michaud and Pingree.

Last night, the FRA joined PHMSA in announcing a public meeting to review federal regulations that apply to the transportation of hazardous materials by rail. According to the agencies, in an effort to continually improve hazardous materials safety, they are seeking input from stakeholders and interested parties. They point out that this review is also part of the Department of Transportation's (DOT) ongoing Retrospective Regulatory Review Initiative pursuant to Executive Order 13563. The details of the public meeting are below:

DATE: August 27-28, 2013, from 8:30 a.m. to 4:30 p.m.

ADDRESS: DOT Conference Center, 1200 New Jersey Avenue, S.E., Washington, DC, 20590 in the Oklahoma Room

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(http://www.facebook.com/pages/Chellie-Pingree/91529332807)

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(http://youtube.com/congresswomanpingree)

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Good that we could pass this bill, but disappointed a clean and comprehensive spending bill still has not been brought[…]

My staff is on lockdown after shots being fired on Capitol Hill. I'm thankful that my team is safe and […]

Republican House members still holding our economy and lives of Americans hostage to their obsession with undermining health care programs.[…]

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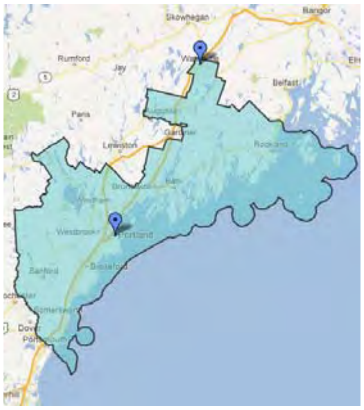

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Exhibit M

Coast Bound Train – The Future of Crude By Rail to the West Coast Part 2

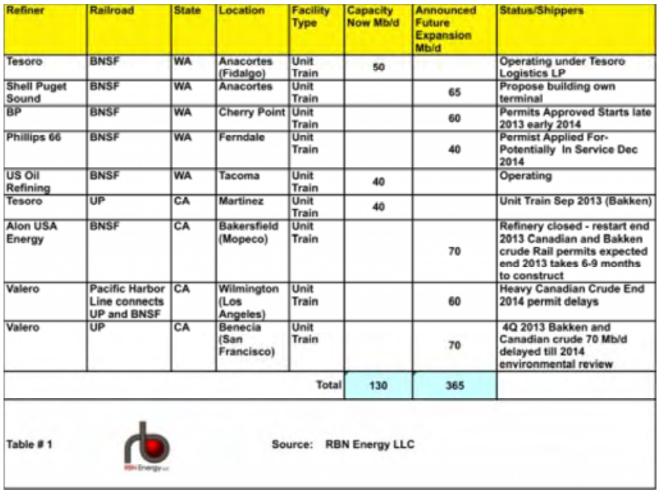
published by Sandy Fielden on Sun, 10/06/2013 - 20:00

The West Coast crude-by-rail terminal build out has been slower to develop than elsewhere in the US. But there are still over 1 MMb/d of unload capacity built or in the planning stages to come online by the end of 2014. Terminals are split between dedicated facilities to serve refineries and merchant terminals that hope to feed multiple refiners. In the absence of pipeline alternatives,,, rail may become the pipeline-on-wheels delivering domestic and Canadian crude to West Coast refineries. Today we conclude our two part review of West Coast crude by rail prospects.

A recent unexpected cancellation of a rail terminal project in Washington State by Targa led to concern that West Coast crude by rail was "over". This two part series looks at current developments to understand if that conclusion is valid. The first episode looked at the economics of moving crude from the Bakken and Western Canada to the West Coast (see Coast Bound Train – The Future of Crude By Rail to the West Coast). The prices that producers in North Dakota and Alberta get for their crude near the wellhead are considerably lower than the West Coast Alaska North Slope (ANS) benchmark. And even though those spreads have fallen from where they were a year ago, they still offer producers the possibility of a higher netback value at the West Coast than sending their crude to the Midwest Cushing trading hub. In this episode we update our survey of the rail unload terminals built or being planned on the West Coast and review future prospects for these facilities.

Two types of rail unload facility are being developed on the West Coast and we will look at each in turn. The first are those being built by individual refiners – usually adjacent to their refineries. Such facilities represent an investment by refiners giving them the option to purchase crude supplies from any location where producers can load crude onto rail cars. When that option is combined with owning rail tank cars, refiners are in an even better position because they don't have to pay monthly lease charges for their rail car fleet. The only drawback to a rail unload facility for refiners is that they may not be able to accommodate enough rail tank cars to meet their crude needs. The typical rail facility developed to handle unit trains with 100 rail cars will be able to unload between 60 and 70 Mb/d of crude. If the refinery capacity is 200 Mb/d of crude – that is not enough. Even a smaller 60 Mb/d refinery would need a lot of storage capacity to avoid disruption to their supply if they depended on one train delivery each day (7 days a week). This is normally not a challenge as long as refiners have alternative supply routes (pipelines, barges etc).

The table below lists the West Coast refinery terminals that our research indicates have been built or are in the process of being built.



Refiner	Railroad	State	Location	Facility Type	Capacity Now Mb/d	Announced Future Expansion Mb/d	Status/Shippers
Tesoro	BNSF	WA	Anacortes (Fidalgo)	Unit Train	50		Operating under Tesoro Logistics LP
Shell Puget Sound	BNSF	WA	Anacortes	Unit Train		65	Propose building own terminal
BP	BNSF	WA	Cherry Point	Unit Train		60	Permits Approved Starts late 2013 early 2014
Phillips 66	BNSF	WA	Ferndale	Unit Train		40	Permist Applied For- Potentially In Service Dec 2014
US Oil Refining	BNSF	WA	Tacoma	Unit Train	40		Operating
Tesoro	UP	CA	Martinez	Unit Train	40		Unit Train Sep 2013 (Bakken)
Alon USA Energy	BNSF	CA	Bakersfield (Mopeco)	Unit Train		70	Refinery closed - restart end 2013 Canadian and Bakken crude Rail permits expected end 2013 takes 6-9 months to construct
Valero	Pacific Harbor Line connects UP and BNSF	CA	Wilmington (Los Angeles)	Unit Train		60	Heavy Canadian Crude End 2014 permit delays
Valero	UP	CA	Benecia (San Francisco)	Unit Train		70	4Q 2013 Bakken and Canadian crude 70 Mb/d delayed till 2014 environmental review
				Total	130	365	

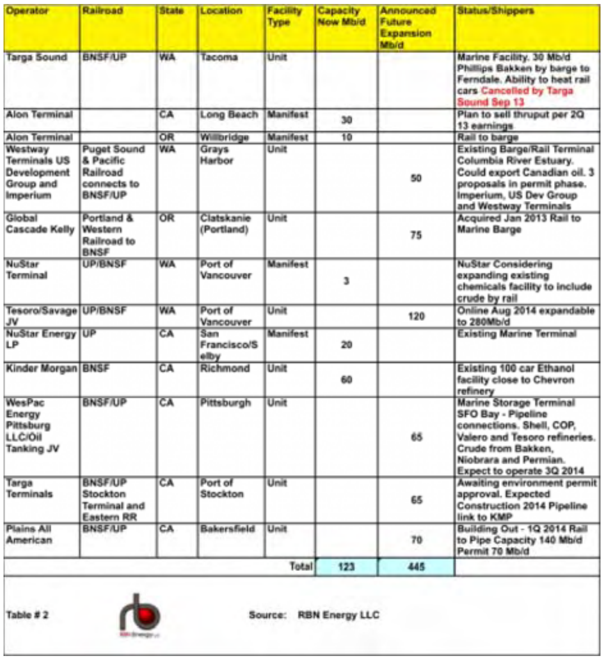
Table # 1 Source: RBN Energy LLC

There are 9 refineries in the table -- 5 in Washington State and 4 in California. Only three of these facilities are currently up and running – the other 6 expect to be operating by the end of next year (2014). Current total capacity is 130 Mb/d that will increase to 495 Mb/d if all the projects get built. The first to build unloading facilities was Tesoro – the largest refiner on the West Coast. They built out the Anacortes, WA rail unload terminal in 2012 and it is currently reportec to be receiving up to 50 Mb/d of Bakken crude – allowing Tesoro to back out ANS crude from their processing slate. The Tesoro refinery at Martinez, CA has recently been upgraded. Tesoro told analysts at the 2Q earnings call that they ran the first unit train of Bakken crude into Martinez this month (September

2013). The other refinery with an unload facility up and running is independent United Refining that is understood to be shipping 40 Mb/d of Bakken crude to their refinery in Tacoma, WA.

Three other large refiners in Washington have rail unload terminal projects underway. The BP Cherry Point refinery has received permits and is building out a 60 Mb/d terminal that will be ready by the end of 2013 or early 2014. The Phillips 66 40 Mb/d facility has applied for permits and will be in service by the end of 2014 if approved. The Shell Anacortes facility is in the planning phase and expected to be 65 Mb/d. In California Alon USA Energy LLC is expecting permits to proceed with its 70 Mb/d facility by the end of 2013. If approved the Alon terminal at Bakersfield, CA will be built in 2014. Valero plans to build terminals at two refineries in California that process heavy crude. Both projects at Wilmington and Benecia are currently delayed by permitting issues and not expected online until the end of 2014. Both the Valero facilities are designed to receive heavy crude oil from Canada in insulated and coiled rail tank cars. They will require special steam heating equipment and heated tanks to handle the crude on arrival.

The second type of rail unload facility is the merchant terminal. Midstream logistics companies operate these – typically to supply crude to multiple refineries. The table below lists the terminals our research identified as built or planned. On the first row is the project at the Port of Tacoma that Targa has cancelled recently as we discussed in episode 1 of this blog series. Interestingly, Targa is continuing with its proposed project to build a marine terminal at the Port of Stockton, CA. That terminal will have unload capacity of 70 Mb/d and allow crude delivered by rail to be transferred to barges or tankers as well as to be delivered to San Francisco Bay area refineries via a Kinder Morgan Partners (KMP) pipeline. Of the four merchant terminals that are already operating, three are small facilities that can only handle manifest rail shipments. These are existing terminals belonging to Alon and NuStar that handle other liquids and have been adapted to receive crude. The Kinder Morgan facility at Richmond, CA is the largest currently operating rail unload terminal that is primarily used for ethanol. It is not clear to what extent this 60 Mb/d facility is being used to ship crude by rail to the nearby Chevron refinery.



Operator	Railroad	State	Location	Facility Type	Capacity Now Mb/d	Announced Future Expansion Mb/d	Status/Shippers
Targa Sound	BNSF/UP	WA	Tacoma	Unit			Marine Facility. 30 Mb/d Phillips Bakken by barge to Ferndale. Ability to heat rail cars Cancelled by Targa Sound Sep 13
Alon Terminal		CA	Long Beach	Manifest	30		Plan to sell thruput per 2Q 13 earnings
Alon Terminal		OR	Willbridge	Manifest	10		Rail to barge
Westway Terminals US Development Group and Imperium	Puget Sound & Pacific Railroad connects to BNSF/UP	WA	Grays Harbor	Unit		50	Existing Barge/Rail Terminal Columbia River Estuary. Could export Canadian oil. 3 proposals in permit phase. Imperium, US Dev Group and Westway Terminals
Global Cascade Kelly	Portland & Western Railroad to BNSF	OR	Clatskanie (Portland)	Unit		75	Acquired Jan 2013 Rail to Marine Barge
NuStar Terminal	UP/BNSF	WA	Port of Vancouver	Manifest	3		NuStar Considering expanding existing chemicals facility to include crude by rail
Tesoro/Savage JV	UP/BNSF	WA	Port of Vancouver	Unit		120	Online Aug 2014 expandable to 280Mb/d
NuStar Energy LP	UP	CA	San Francisco/Selby	Manifest	20		Existing Marine Terminal
Kinder Morgan	BNSF	CA	Richmond	Unit	60		Existing 100 car Ethanol facility close to Chevron refinery
WesPac Energy Pittsburg LLC/Oil Tanking JV	BNSF/UP	CA	Pittsburgh	Unit		65	Marine Storage Terminal SFO Bay - Pipeline connections. Shell, COP, Valero and Tesoro refineries. Crude from Bakken, Niobrara and Permian. Expect to operate 3Q 2014
Targa Terminals	BNSF/UP Stockton Terminal and Eastern RR	CA	Port of Stockton	Unit		65	Awaiting environment permit approval. Expected Construction 2014 Pipeline link to KMP
Plains All American	BNSF/UP	CA	Bakersfield	Unit		70	Building Out - 1Q 2014 Rail to Pipe Capacity 140 Mb/d Permit 70 Mb/d
				Total	123	445	

Table # 2 Source: RBN Energy LLC

As with the refinery facilities, the list of merchant terminal projects waiting for approval and build out is longer than the working terminals list. Two of the largest projects are located in Washington State. Potentially the bigger of these two will be at Grays Harbor – a rail to barge facility on the Chehalis River estuary owned by Westway Terminals. Three separate companies have plans underway to unload crude from rail cars at Grays Harbor through two seperate terminals. Two of these projects (Westway and Imperium) now await environmental impact studies and the third (US Development) has yet to start the permitting process. All will use the same short line railroad. It is unclear what the total unload capacity will be – our estimate of 50 Mb/d is conservative. The second Washington State project awaiting approval is the Tesoro/Savage joint venture at the Port of Vancouver, WA that is expected online in August 2014 subject to permitting. This terminal is designed to handle 120 Mb/d of crude initially expandable to 280 Mb/d and will handle crude from the Bakken destined fo California by barge or exports of Canadian crude. A Global Partners LP facility in Clatskanie near Portland, OR is an ethanol marine rail-to-barge facility that is being expanded to handle 75 Mb/d of Bakken crude (Global has a load terminal at Beulah in North Dakota on the BNSF railroad).

The last three terminals in the project list are in California. We already mentioned the Targa Stockton facility. The WesPac Energy Pittsburg LLC and Oiltanking joint venture is located at Pittsburgh, near San Francisco. This project will supply crude by rail to marine storage and by pipeline to refineries in the Bay area. Crude supplies will be delivered from the Bakken as well as the Niobrara in the Rockies and the Permian Basin in West Texas. The Plains All American facility in Bakersfield, CA is one of the 5 terminals that Plains purchased from US Development in 2012. The terminal has received a permit to unload up to 70 Mb/d (Plains planned to build 140 Mb/d capacity) and will be online during the first quarter of 2014. All the large merchant terminals in California are being built to connect into existing pipeline networks to feed refineries.

Summing up, the currently operating merchant unload capacity is 123 Mb/d with a further 445 Mb/d on the project list. If all the projects make it through permitting, then the total capacity will be 567 Mb/d. Adding that total to the 495 Mb/d built and planned at refineries and we reach a grand total of 1,,012 Mb/d – just over 1 million b/d or about 43 percent of total California and Washington State refining capacity of 2.35 MMb/d.

Future of West Coast Crude by Rail

In Part 1 of this series we established that the economics of crude by rail to the West Coast from North Dakota and Western Canada still look good. Our survey of terminal capacity built or underway in this blog episode has shown that there is plenty of ongoing investment in crude by rail logistics on the West Coast – even if quite a few projects are tied up in permitting. It is therefore unlikely that the Targa Sound terminal project was cancelled simply because the economics did not look good on paper. It may be that locating a merchant terminal at Tacoma was inexpedient because so many area refineries are developing their own unload facilities. If those refiners have their own railcars and facilities then using a third party terminal would just add to their costs. Targa is still pursuing permits for their terminal in Stockton, CA where Valero and Alon are the only refiners building their own unload facilities (so far).

Otherwise the crude by rail unload terminal opportunity continues to look promising for West Coast destinations. There are still no pipelines across the Rockies so rail has no direct competition. The only pipeline project to reach the drawing board so far failed to attract enough shipper support and was shelved (the Kinder Morgan Freedom project from West Texas to California – see Is the Price of Freedom Too High?). Rail load terminals being built in the Rockies and the Permian basin are targeting West Coast destinations (see Load Terminal Craze Sweeps the Nation). The Rockies terminals will either ship local crude from the Niobrara or crude coming off pipelines from Canada and the Bakken. Permian Basin terminals will ship West Texas Intermediate (WTI) or West Texas Sour (WTS) crude.

Only the Valero terminals in California are designed to handle heavy crude from Canada although several California refineries process this type of crude. Californian refineries have also previously processed waxy crudes from Asia and may be interested to receive Uinta Basin crudes by rail from Utah (see Do Ya Think I'm Waxy?).

We expect to see terminal unload capacity grow in California as permits are achieved. The merchant terminals in California are being built to link to existing pipeline infrastructure and look set to become permanent features of the crude distribution system. Indeed, given the shelving of the Freedom pipeline project and the cost of building a pipeline across the Rockies, rail may well become the "pipeline-on-wheels" delivering domestic crude to the West Coast. In the Northwest it remains to be seen what the market is for crude delivered to marine facilities. Since local refiners are building their own facilities the only market is for barge movements to California or exports of Canadian crude delivered by rail. Presumably more California demand will be met by the merchant terminal build outs that we have described. The jury is still out on whether a Canadian crude export market develops from the US West Coast.

In conclusion, the Targa project cancellation is more of a bump in the road than a roadblock. The West Coast remains a viable destination for domestic and Canadian crude supplies delivered by rail. This market will become more interesting next year when the Gulf Coast receives the expected flood of new pipeline crude supplies potentially putting downward pressure on crude prices in that region. In that event the netbacks for producers shipping crude West would improve and we could well see significant supplies shipped by rail from Texas to California.

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Tags: Crude Oil Crude by Rail West Coast Terminals Canadian crude Refineries Pipelines Category: Crude Oil

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Exhibit N

Environ. Sci. Technol. **2010,** *44,* 9584–9589

Combustion Emissions from Refining Lower Quality Oil: What Is the Global Warming Potential?

GREG KARRAS*

Communities for a Better Environment (CBE), 1904 Franklin Street, Suite 600, Oakland, California 94612, United States

Received June 11, 2010. Revised manuscript received October 25, 2010. Accepted November 14, 2010.

The greenhouse gas emission intensity of refining lower quality petroleum was estimated from fuel combustion for energy used by operating plants to process crude oils of varying quality. Refinery crude feed, processing, yield, and fuel data from four regions accounting for 97% of U.S. refining capacity from 1999 to 2008 were compared among regions and years for effects on processing and energy consumption predicted by the processing characteristics of heavier, higher sulfur oils. Crude feed density and sulfur content could predict 94% of processing intensity, 90% of energy intensity, and 85% of carbon dioxide emission intensity differences among regions and years and drove a 39% increase in emissions across regions and years. Fuel combustion energy for processing increased by approximately 61 MJ/m^3 crude feed for each 1 kg/m^3 sulfur and 44 MJ/m^3 for each 1 kg/m^3 density of crude refined. Differences in products, capacity utilized, and fuels burned were not confounding factors. Fuel combustion increments observed predict that a switch to heavy oil and tar sands could double or triple refinery emissions and add 1.6–3.7 gigatons of carbon dioxide to the atmosphere annually from fuel combustion to process the oil.

Introduction

Replacing limited conventional crude oil (*1*) with heavy oil and natural bitumen (tar sands) resources could have substantial energy and environmental costs (*2*). Physical and chemical properties of the lower quality, heavier, more contaminated oils predict the combustion of more fuel for the energy necessary to convert them into product slates dominated by light hydrocarbon liquids (*3*–*8*). Preliminary estimates from fuel cycle analyses suggest that a switch to heavy oil and tar sands could increase the greenhouse gas emission intensity of petroleum energy by as much as 17–40%, with oil extraction and processing rather than tailpipe emissions accounting for the increment (*3, 4*). This raises the possibility that a switch to these oils might impede or foreclose the total reduction in emissions from all sources that is needed to avoid severe climate disruption. Accurate prediction of emissions from substitutes for conventional petroleum is therefore critical for climate protection. However, estimates of the emissions from processing lower quality oils have not been verified by observations from operating refineries.

Crude oils are extremely complex, widely ranging mixtures of hydrocarbons and organic compounds of heteroatoms and metals (*2, 7*). Refiners use many distinct yet interconnected processes to separate crude into multiple streams, convert the heavier streams into lighter products, remove contaminants, improve product quality, and make multiple different products in varying amounts from crude of varying quality (*5*–*11*). Factors that affect emissions from refinery process energy consumption include crude feed quality, product slates, process capacity utilization, fuels burned for process energy, and, in some cases, preprocessing of refinery feeds near oil extraction sites. Estimates that construct process-by-process allocations of emissions among these factors have not been verified by observations from operating refineries in part because publicly reported data are limited for refinery-specific crude feeds and unavailable for process-level material and energy inputs and outputs (*4*–*6*). Research reported here distinguishes effects of crude feed quality on processing from those of the other factors using refinery-level data from multiple operating plants to estimate and predict the process energy consumption and resultant fuel combustion emissions from refining lower quality oil.

Experimental Section

Refinery crude feed volume, density, and sulfur content, process capacity, capacity utilization, yield, and fuels were reported annually for each U.S. Petroleum Administration Defense District from 1999 to 2008 (*9, 10*). See the Supporting Information for this data (Table S1, Supporting Information). Districts 1 (East Coast-Appalachia), 2 (Midwest), 3 (Gulf Coast and vicinity), and 5 (West Coast, AK, and HI) each refined diverse crude feeds (19–41 source countries) at multiple facilities. Smaller, landlocked District 4 (Rocky Mountain states) refined nondiverse crude feeds (2–3 source countries).

At concentrations 4–8 times those of nitrogen and 160–500 times those of nickel and vanadium, sulfur is the major process catalyst poison in crude by mass (*2, 11*). In addition, for diverse blends of whole crude oils from many locations and geologic formations, distillation yield, and asphaltic, nitrogen, nickel, and vanadium content are roughly correlated with density and sulfur (*2, 7*). Variability in the effects of unreported crude feed characteristics on processing is thus constrained by the density and sulfur content of well-mixed crude feeds. Mixing analysis suggested that density and sulfur are reasonably reliable predictors of natural variability in unreported characteristics for annual crude feeds processed in Districts 1, 2, 3 and 5 but could not exclude the potential for unpredicted effects in processing the poorly mixed District 4 feed (Table S2, Supporting Information). The District 4 feed also was proportionately higher in synthetic crude oil (SCO) than those of other districts (Table S3, Supporting Information), and variant hydrogen production that was not predicted by crude feed density was found in District 4 (Table S4, Supporting Information). SCO may increase refinery hydroprocessing requirements (*12, 13*). High hydrogen capacity coincided with SCO refining in Districts 2 and 4 during 1999–2008, but the effect on refinery energy was minimal in District 2, while it was significant and more variable in District 4; other anomalies in the District 4 feed might cause this effect (Tables S2 and S4, Supporting Information). For these reasons, District 4 data were excluded from analysis of refinery observations and used only in estimates including upgrading for SCO. Districts 1, 2, 3, and 5 accounted collectively for 97% of U.S. refining capacity, 1999–2008. Analysis compared the reported data among these districts and years for interactions of the variables defined below.

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10.1021/es1019965

Oil quality *(OQ)* was defined as the density (d) and sulfur content (S) of crude feeds in mass per cubic meter (1 m^3, 6.29 barrels oil; 264 gallons). The density of crude oils is proportional to the fraction of higher molecular weight, higher boiling point, larger hydrocarbon compounds in the oils that are distilled in a vacuum, then cleaved (cracked) into fuel-size compounds to make light hydrocarbon fuels. The larger hydrocarbons have lower hydrogen/carbon ratios that require hydrogen addition to improve product quality and higher concentrations of sulfur and other catalyst poisons that are freed by cracking and bonded with hydrogen to remove them from the oil and protect process catalysts (*2, 11*). This hydrocracking and hydrotreating of gas oil and residua uses several times more hydrogen than does hydrotreating of lighter streams such as naphtha (*11*). These processing characteristics require increased capacity for vacuum distillation, cracking, and hydroprocessing of gas oil and residua in refineries designed to make light liquid products from heavier, higher sulfur crude oils (*4, 8, 14*).

Crude processing intensity (*PI*) was thus defined as the ratio by volume of vacuum distillation capacity, conversion capacity (catalytic, thermal, and hydrocracking), and crude stream (gas oil and residua) hydrotreating capacity to atmospheric crude distillation capacity. These processes account for the primary processing acting on the crude and "reduced crude" that *Speight* distinguishes from secondary processes acting on product streams such as gasoline, naphtha, and distillate oils (*7*). PI measures the increasing portion of the crude input fed to these processes that is predicted by worsening *OQ* (increasing d, S, or both) and indicates the additional energy needed for heat, pressure, and reactants such as hydrogen to process those increasing feed volumes. It also defines an operational distinction between "crude stream" processing that acts on crude, gas oils, and residua and the subsequent "product stream" processing that acts on the unfinished products from crude stream processing. This distinction was useful in the absence of reported data for more detailed process-level analyses of material and energy flows. *PI* was analyzed with refinery-level crude feed, fuel, capacity utilization, and product yield data to verify the refinery process energy predicted by *OQ*.

Energy intensity (*EI*) was defined as total refinery process energy consumed per volume crude feed, based on reported fuels consumed (Table S1, Supporting Information). Purchased fuels consumed by refiners, such as electric power from the transmission grid, were included in *EI*. Energy used by hydrogen production plants was estimated based on 90% of production capacity and data for new natural gas-fed steam methane reforming facilities (*10, 15*, Table S1, Supporting Information). *EI* integrates all factors in refineries that consume fuel energy, allowing analysis of *EI* with *OQ* and processing to account for refinery capacity utilized and yield.

Effects of variable product slates on refinery energy consumption were distinguished from those of *OQ* in five ways. First, product slate effects on the relationships observed among crude feed quality, crude stream processing, and energy were estimated directly. This was done by including the products ratio, defined as the volume of gasoline, kerosene, distillate, and naphtha divided by that of other refinery products, as an explanatory variable in comparisons of *OQ*, *PI*, and *EI*. Second, the products ratio, combined yield of gasoline and distillate, and combined yield of petroleum coke and fuel gas were analyzed with *EI* and *OQ*. This quantified changes in refinery energy with yield and changes in yield with crude feed quality for key conversion products and byproducts. Third, energy use was analyzed with product stream process capacities to estimate changes in *EI* that could be explained by changes in product processing rates. Fourth, effects of product stream processing on energy for hydrogen were compared with those of crude stream processing by analyzing hydrogen production capacity with product hydrotreating capacity, hydrocracking capacity, and *OQ*. Finally, estimated total energy for processing product slates (Eproducts) was analyzed with *OQ*. Eproducts was estimated based on product-specific factors developed by Wang et al. (*6*) and yield data (Tables S1 and S5, Supporting Information). Refinery capacity utilization was included as an explanatory variable in all comparisons.

Analysis was by partial least squares regression (PLS, XLSTAT 2009). PLS was used based on the expectation that explanatory (x) variables may be correlated, the primary interest in prediction of y (e.g., *EI*) and a secondary interest in the weights of x variables (e.g., S and d) in predicting y. Distributions of PLS residuals appeared normal (Shapiro-Wilk; Anderson-Darling; Lilliefors; Jarque-Bera tests, α 0.05).

Synthetic Crude Oil (SCO). Coking- and hydrocracking-based upgrading of bitumen in Western Canada uses energy to yield SCO that has poor gas oil and distillate qualities but lower density and sulfur than the bitumen (*12, 13*). Refinery crude feeds and energy consumption do not reflect the original bitumen quality for this SCO or the energy used in its upgrading. SCO comprised appreciable fractions of annual crude feeds in Districts 2 (2−8%) and 4 (2−12%), based on limited estimates that may exclude SCO in some blended oil streams (Table S3, Supporting Information). Process modeling data for energy consumed and density and sulfur lost in coking- and hydrocracking-based upgrading (*16*) were applied to the estimated SCO volume in refinery feeds (Table S3, Supporting Information). Districts and years were compared for total processing (upgrading and refining) energy estimated and that predicted by including estimated original oil quality (d, S) in the prediction mode of the PLS model based on refinery observations (Table S6, Supporting Information).

Emissions. Emissions were assessed for carbon dioxide (CO_2), the predominant greenhouse gas emitted by refineries (Table S7, Supporting Information). Direct measurements for all emission vents were not reported. Observed fuel consumption and fuel-specific emission factors developed by the U.S. Energy Information Administration (*17, 18*) were used to estimate "observed" emissions, and estimation details were documented (Table S1, Supporting Information). Fuel energy consumed ranged more widely among districts and years than the emission intensity of the fuel mix. Emissions predicted by *OQ* were based on *EI* predicted by *OQ* results from PLS and the emission intensity of the fuel mix. Observed and predicted emissions were compared among districts and years by PLS. Emissions estimates by government agencies (*5, 19−21*) that could be matched to data for *OQ* were superimposed on this comparison by including their *OQ* and predicted *EI* values in the prediction mode of the PLS models for the districts data (Tables S8 and S9, Supporting Information).

For heavy oil and natural bitumen, *OQ* data reported by the U.S. Geological Survey (*2*) and the average (1999−2008) U.S. refinery capacity utilization and products ratio were used in the prediction mode of the PLS model for observed *EI* versus *OQ* to predict *EI* (Table S8, Supporting Information). Predicted emissions from heavy oil and natural bitumen were derived from the products of these *EI* predictions (95% confidence for observations) and the emission intensity of the average (1999−2008) U.S. refinery fuel mix.

Results

Figure 1 shows results from comparisons of *OQ*, *PI*, and *EI* among districts and years from 1999 to 2008. Observed *OQ* ranges by 7.85 kg/m^3 crude feed (kg/m^3) for S and 37.6 kg/m^3 for d. Observed *PI* ranges by 0.42, or 42% of atmospheric crude distillation capacity. Observed *EI* ranges by 1.89 GJ/m^3 crude feed. *PI* is strongly and positively associated with

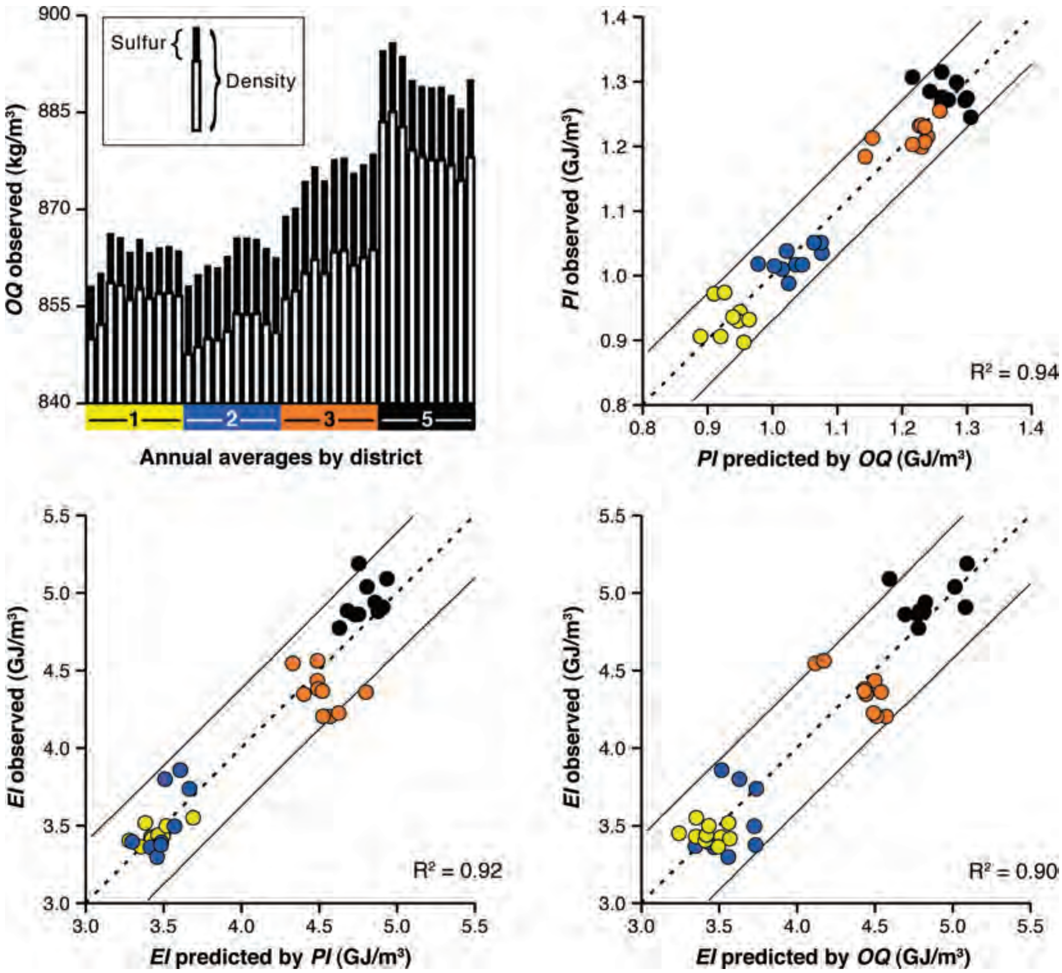

FIGURE 1. Increasing crude processing intensity and energy intensity with worsening oil quality. *OQ:* Crude feed oil quality. *PI:* Crude processing intensity. *EI:* Refinery energy intensity. Observations are annual weighted averages for districts 1 (yellow), 2 (blue), 3 (orange), and 5 (black) in 1999−2008. Diagonal lines bound the 95% confidence of prediction for observations.

worsening *OQ* (increasing *d*, *S*, or both). *EI* is strongly and positively associated with worsening *OQ* and increasing *PI*. *EI* increases by approximately 44 MJ/m^3 for each 1 kg/m^3 *d* and 61 MJ/m^3 for each 1 kg/m^3 *S* based on the PLS regression analysis for *EI* versus *OQ*. The equation of the model (*EI* vs *OQ*) can be expressed as

$$EI = 0.044d + 0.061S + 0.010(\text{Capacity utilized}) - 0.159(\text{Products ratio}) - 35.092 \quad (1)$$

where *EI* is the central prediction in GJ/m^3, *d* is in kg/m^3, *S* is in kg/m^3, capacity utilized is in percent, products ratio is expressed as a quotient, and the last term is the coefficient for the intercept.

Table 1 shows additional results from analysis of refinery observations. *PI* increases strongly with *d* and *S* (95% confidence for observations). *EI* increases strongly with *d* and *S* and with vacuum distillation, conversion, and crude stream hydrotreating capacities. Hydrogen production capacity increases strongly with *d* and hydrocracking capacity. Sulfur recovery capacity increases strongly with *S*. These observations describe increasing portions of crude feeds processed by crude stream capacity and resultant effects on total refinery energy consumption as crude density and sulfur content increase.

In contrast to crude stream processing, except for cracking byproducts and two processes that treat them, product slate indicators are not significant or decrease with increasing *OQ* and *EI*. The products ratio is not significant in the strong relationships among *EI*, *PI*, and *OQ*, perhaps in part because light liquids yield is less variable than *S* or *EI* among these districts and years. However, the ratio of light liquids to other products decreases with increasing *d* (products ratio vs *OQ*) and *EI* (*EI* vs products processing), and yield shifts, from gasoline and distillate to coke and fuel gas, as *OQ* worsens and *EI* increases.

Products processing reflects this shift from light liquids to cracking byproducts. Product stream hydrotreating, reforming, asphalt, aromatics, and polymerization/dimerization capacities decrease as *EI* increases. Those five processes account for 83−90% of total product stream processing capacity among districts (Table S1, Supporting Information). Among products processes, only alkylation and isomerization (7−13% of products capacity), which receive light streams from conversion processes, are positively associated with *EI*. Product hydrotreating cannot explain the observed increase in hydrogen production with increasing *d*. Estimated refinery energy use for products processing (Eproducts) decreases with increasing *d*. These results appear to measure the decreasing fraction of crude inputs converted to light liquid product streams and increasing creation of cracking byproducts such as coke and fuel gas that result from incomplete conversion as crude feed density and sulfur increase.

A weak inverse association of hydrogen production with product hydrotreating capacity (Table 1) results from a strong increase in H_2 capacity with *d* and hydrocracking, a steady decrease in the hydrotreating/hydrocracking ratio with increasing H_2 capacity, and lower hydrotreating at high

TABLE 1. Results from Refinery Crude Feed Quality, Processing, Energy, Yield, and Emission Comparisons[a]

effects of crude feed oil quality (*OQ*)

y vs *x*	R^2	standardized coefficients of *x* variables (coeff)			
		density	sulfur	cap. utilized	products ratio
process intensity *(PI)* vs *OQ*	0.94	**0.73**	**0.42**	**0.09**	−0.02
energy intensity *(EI)* vs *OQ*	0.90	**0.80**	**0.23**	0.05	−0.10
hydrogen production vs *OQ*	0.91	**1.09**	−0.01	0.05	**0.35**
sulfur recovery vs *OQ*	0.94	−0.01	**0.95**	−0.06	**−0.15**
pet. coke + fuel gas vs *OQ*	0.95	**0.80**	**0.34**	−0.04	
gasoline + distillate vs *OQ*	0.75	**−0.85**	−0.07	−0.04	
products ratio vs *OQ*	0.26	**−0.40**	−0.12	0.17	
Eproducts vs *OQ*	0.74	**−0.61**	0.13	**0.49**	

effects of oil quality (*OQ*) and fuels on CO_2 emissions

y vs *x*	R^2	standardized coefficients of *x* variables (coeff)	
		EI predicted by *OQ*	fuel mix emission intensity
observed vs predicted CO_2	0.85	**0.88**	−0.04

effects of processing and products yield

y vs *x*	R^2	coeff.	*y* vs *x*	R^2	coeff.
EI vs *PI*	0.92		*EI* vs yield	0.93	
vacuum distillation		**0.35**	pet. coke + fuel gas		**0.59**
conversion capacity		**0.35**	gasoline + distillate		**−0.42**
csHydrotreating		**0.22**	capacity utilized		−0.01
capacity utilized		**−0.16**	products ratio		−0.02
products ratio		−0.14			
			EI vs psProcessing	0.91	
H_2 production vs hydrocracking	0.97		psHydrotreating		**−0.17**
hydrocracking		**1.02**	reforming		**−0.19**
capacity utilized		−0.06	asphalt		**−0.30**
products ratio		**0.14**	aromatics		**−0.33**
			polym./dimerization		**−0.25**
H_2 production vs product-stream hydrotreating	0.18		lubricants		0.04
			alkylation		**0.30**
psHydrotreating		**−0.33**	isomerization		**0.24**
capacity utilized		−0.09	capacity utilized		−0.06
products ratio		**−0.17**	products ratio		**−0.33**

[a] *R*-squared values and standardized coefficients from PLS regressions on annual data from refining districts 1, 2, 3 and 5, 1999−2008. **Boldface**: significant at 95% confidence. Eproducts: estimated energy use to process a given product slate. Prefix cs (ps): crude stream (product stream) processing.

H_2 capacity among these districts and years (Figure S1, Supporting Information). Refinery capacity utilization was not significant in the effects of *OQ* on *EI* and affected the relationships between *PI* and *OQ* and between *PI* and *EI* only marginally, possibly because capacity utilization varied little among districts and years (Table S1, Supporting Information). Significant capacity utilization results are consistent with marginally increased energy consumption and decreased flexibility to process lower quality crude when refineries run closer to full capacity.

Rough estimates including the energy, d, and S lost in bitumen upgrading for SCO refined reveal greater effects of total processing for crude feeds refined in Districts 2 and 4 and follow the relationships observed in refining (Figure 2). Estimated total processing energy falls within the prediction based on *OQ* from refinery observations in 43 of 50 cases and exceeds the 95% confidence of prediction by more than 2% only in two cases explained by District 4 hydrogen anomalies discussed above. Oil quality−energy relationships observed in refining can predict those for total processing because upgrading and refining use similar carbon rejection, hydrogen addition, and utility technology.

Emissions calculated from observed fuels consumed are strongly and positively associated with *EI* predicted by *OQ* (Table 1) and range by 39%, from 257 to 358 kg/m^3 crude feed (Figure 3). Observed emissions fall within the 95% confidence of prediction based on *OQ* in 36 of 40 cases and are within 3% of the confidence of prediction in all cases. Despite emission differences among fuels, the fuel mix is not significant in this prediction. The emission intensity of the fuel mix varies much less than *EI* and decreases slightly with decreasing petroleum coke contributions and a shift in cracking processes as *EI*, d, and S increase (Table S1 and Figure S1, Supporting Information). Refinery emission estimates by government agencies that could be matched to *OQ* differ from each other by as much as 12−30% but fall within 2% of the central prediction based on *OQ* or within 4% of its confidence interval (*5, 19*−*21*, Table S8, Supporting Information). The 2008 San Francisco Bay Area estimate in Figure 3 (360 kg/m^3) is close to estimated 2008 California refinery emissions (354 kg/m^3) (*21*), for which matching *OQ* data were not available. California gasoline and diesel production may account for 56% (197.2 kg) and 22% (78.7 kg) of this 354 kg/m^3, respectively, based on fuel-specific estimates for the average California crude feed (*21*−*23*, Table S8, Supporting Information).

Predictions for heavy oil (957.4 kg/m^3 d; 27.8 kg/m^3 S) and natural bitumen (1 033.6 kg/m^3 d; 45.5 kg/m^3 S) (USGS average) (*2*) reflect their low quality compared with crude feeds observed (Figure 1). On the basis of the PLS model for

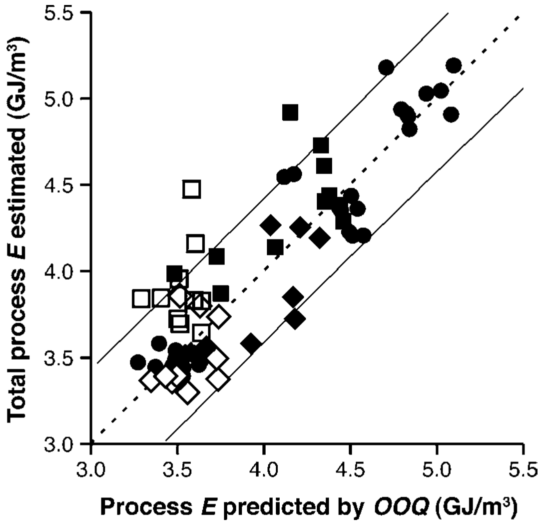

FIGURE 2. Estimated process energy for bitumen upgrading and refining versus that predicted by oil quality (GJ/m^3 crude), 1999−2008. *OOQ:* original oil quality including bitumen quality for synthetic oil inputs. Black diamonds: District 2. Black squares: District 4. Black circles: Districts 1, 3, and 5. White diamonds (squares): District 2 (District 4) refinery energy and oil quality only. Diagonal lines bound the 95% confidence of prediction for refinery observations.

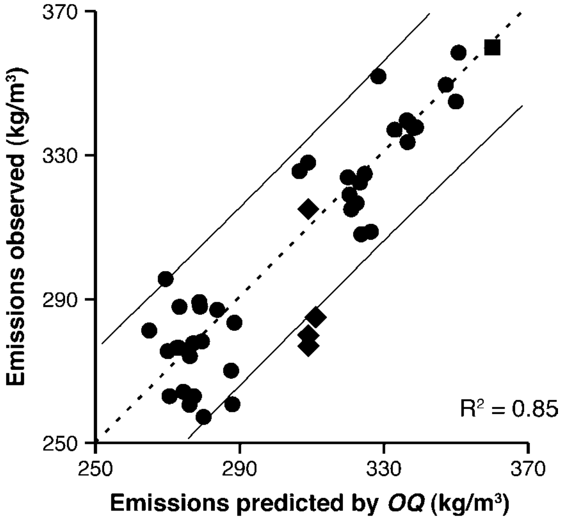

FIGURE 3. Refinery CO_2 emission intensity observed versus predicted by oil quality. *OQ:* Oil quality. Black circles: District 1, 2, 3, or 5 annually, 1999−2008. Black diamonds: United States in 2002, 2005, 2006, 2007. Black square: San Francisco Bay Area in 2008. Diagonal lines bound the 95% confidence of prediction for observations. R^2 value shown is for the comparison among districts and years.

observations from Districts 1, 2, 3, and 5 (*EI* vs *OQ*) and the emission intensity of the U.S. refinery fuel mix (73.8 kg/GJ), processing the range of heavy oil/bitumen blends could use 8.23−14.13 GJ/m^3 fuel (Table S8, Supporting Information) and emit 0.61−1.04 t/m^3 CO_2.

Discussion

Strongly coupled increases in energy and crude stream processing intensities with worsening oil quality (Figure 1) describe energy for carbon rejection, aggressive hydrogen addition, and supporting processes acting on larger portions of heavier, higher sulfur crude feeds to yield light liquid product streams. The creation of cracking reaction byproducts that limits conversion of heavier oils to light liquid product streams is observed in the shift from gasoline and distillate to coke and fuel gas yield as *OQ* worsens and *EI* increases. Observed decreases in light liquids yield and most major product stream processes as *EI* increases are consistent with this rising reliance on incomplete conversion. Differences in product slates cannot explain increasing *EI* as *OQ* worsens because capacities of processes comprising 83−90% of product stream processing capacity decrease as *EI* increases, and estimated energy use for products processing decreases as *OQ* worsens. Hydrogen production increases with crude density and hydrocracking. *EI* drives emissions variability. *OQ* predicts 94% of *PI*, *PI* predicts 92% of *EI*, and *OQ* predicts 90% of *EI* and 85% of emissions variability. These observations from operating plants across the four largest U.S. refining districts over 10 years provide evidence that crude feed density and sulfur content predict processing, energy, and CO_2 emission intensities for large groups of refineries with diverse feeds.

Slight, unexpected decreases in product hydrotreating at high hydrogen production and in fuel mix emission intensity with increasing *d* and *S* can be explained by a coincident shift from hydrotreating and catalytic cracking to hydrocracking with worsening *OQ*. Refiners can substitute hydrocracking for hydrotreating and catalytic cracking to some extent. *OQ*, along with other factors beyond this study scope, may influence those business decisions.

Energy increments predicted by density (44 MJ/kg) and sulfur (61 MJ/kg) in crude feeds (eq 1) compare to energy inputs of 40−70 MJ/kg density (including sulfur) lost from bitumen upgrading for SCO, based on process modeling of coking- and hydrocracking-based upgraders ((*16*), Table S6, Supporting Information). At an energy cost of 16.4 MJ/m^3 (Table S1, Supporting Information), hydrogen for density reduction by hydrocracking could account for 44 MJ/kg, based on the H_2/oil feed ratio of 308 m^3/m^3 Robinson and Dolbear report for 22°API feed and 44°API yield (*11*).

Results help to explain differences among government estimates of refinery emissions (Figure 3) and support the high case fuel cycle emission increments from a switch to heavy and tar sands oils reported for gasoline by Brandt and Farrel (+40%) (*3*) and for diesel by Gerdes and Skone (+17%) (*4*). Predicted emissions from processing heavy oil/natural bitumen blends (0.61−1.04 t/m^3) are 2−3 times the average of observed and estimated emissions in Figure 3 (0.30 t/m^3). Assuming this 0.30 t/m^3 refining average and 2007 world petroleum emissions (11.27 Gt) (*24*) as a baseline, processing heavy oil/bitumen blends at 2009 world refining capacity (5.06×10^9 m^3) (*10*) could increase annual CO_2 emissions by 1.6−3.7 gigatons and total petroleum fuel cycle emissions by 14−33%. Extraction emissions would add to these percentages.

This prediction applies to average CO_2 emissions from large, multiplant refinery groups with diverse, well-mixed crude feeds and appears robust for that application. However, the method used here should be validated for other applications. If it is applied to different circumstances, the potential for significantly different product slates, poorly mixed crude feeds, synthetic crude oil impacts on refining, and effects on fuel mix emission intensity and hydrotreating resulting from choices among carbon rejection and hydrogen addition technologies should be examined.

Several issues suggest future work. Other properties of crude feeds and incremental efficiencies from modernization of equipment and catalyst systems might explain up to 10% of the variability in *EI* observed among U.S. refining districts and years and could be more important for single plants and nondiverse crude feeds. Burning more fuel to refine lower quality oil emits toxic and ozone−precursor combustion products along with CO_2. Pastor et al. estimate that refinery emissions of such "co-pollutants" dominate health risk in nearby communities associated with particulate matter emitted by the largest industrial sources of greenhouse gases in California and identify racial disparities in this risk as important in emission assessment (*25*). Better facility-level *OQ* data could improve local-scale pollutant assessment. Better crude quality predictions could improve energy, and climate protection, forecasts. Assessments of the need, scope, and timing for transition to sustainable energy should account for emissions from lower quality oil.

Acknowledgments

This work was funded by Communities for a Better Environment (CBE) with support received through membership dues and portions of grants by The Richard & Rhoda Goldman Fund, The Kresge Foundation, The Ford Foundation, and The San Francisco Foundation.

Supporting Information Available

Data and details of methods, analyses, and results. This material is available free of charge via the Internet at http://pubs.acs.org.

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Exhibit O

ATTACHMENT H

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Final Environmental Assessment:

Proposed Amended Rule 1149 – Storage Tank and Pipeline Cleaning and Degassing

April 2008

SCAQMD No. 080304JK
SCH No. 2008031034

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SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
GOVERNING BOARD

PREFACE

This document constitutes the Final Environmental Assessment (EA) for the Proposed Amended Rule 1149 – Storage Tank and Pipeline Cleaning and Degassing. The Draft EA was released for a 30-day public review and comment period from March 11, 2008 to April 9, 2008. One comment letter was received from the public and is included with a response to the comment in Appendix D.

To ease in identification, modifications to the document are included as underlined text and text removed from the document is indicated by ~~strikethrough~~. PAR 1149 has been revised subsequent to the release of the Draft EA for public review and comment. Brief summaries of the primary changes made to PAR 1149 are presented in the following bulleted items.

- Commenters on PAR 1149 have stated that it would be difficult to estimate the true vapor pressure in the field. Therefore, the low vapor pressure requirement was changed back to Reid vapor pressure (RVP) instead of true vapor pressure (TVP). The change would ensure verification of VOC emission reductions. The change would not affect the environmental analysis.
- Commenters on PAR 1149 have stated that based on a strict reading of PAR 1149, it is not clear that owner/operators would be allowed to attach emission control devices to the pipelines. Language was added clarifying that control devices are allowed to be attached to pipelines. Since the intent of PAR 1149 would be the control of emissions from pipelines, the added language would clarify that the intent of allowing control equipment to be attached to pipelines is part of the proposed project. The addition of control equipment to pipelines was evaluated in the Draft EA. The change would not affect the environmental analysis.
- PAR 1149 has been modified to remove the notification and review process from the greenhouse gas quantification protocol. Since the impacts from the protocol were determined to be speculative, no analysis of the protocol was included in the Draft EA. The removal of the notification and review process; therefore, would not affect the environmental analysis.
- Commenters on PAR 1149 have stated that an additional activated carbon adsorption unit would be required during sludge removal under PAR 1149. This would require an additional activated carbon adsorption unit at up to 192 tanks annually. Sludge is only accumulated in storage tanks that hold heavy product; gasoline storage tanks are not expected to contain sludge. The environmental analysis has been updated to include this information, which does not change any conclusions.
- One storage tank owner/operator has stated that the support legs on approximately 14 of their drain dry tanks would need to be shortened to comply with PAR 1149. The construction would occur over four years to reduce the operating and financial impacts to the storage tank owner/operator and potential disruption to the delivery of fuel supplies to the market. Based on this, only one storage tank would be altered at a time. The environmental analysis has been updated to include this information. This modification does not change any conclusions in the environmental analysis.

Based on the revised analysis, there would be no new significant adverse impacts, a substantial increase in the severity of an environmental impact, or changes to any conclusions made in the Draft EA. Therefore, these changes would not affect the overall conclusions in the Draft EA.

None of the modifications alter any conclusions reached in the Draft EA, nor provide new information of substantial importance relative to the draft document. As a result, these minor revisions do not require recirculation of the document pursuant to CEQA Guidelines §15073.5. This document constitutes the Final EA for 1149 – Storage Tank and Pipeline Cleaning and Degassing.

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CHAPTER 1 - PROJECT DESCRIPTION

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INTRODUCTION

The California Legislature created the South Coast Air Quality Management District (SCAQMD) in 1977[1] as the agency responsible for developing and enforcing air pollution control rules and regulations in the South Coast Air Basin (Basin) and portions of the Salton Sea Air Basin and Mojave Desert Air Basin (collectively known as the "district"). By statute, the SCAQMD is required to adopt an air quality management plan (AQMP) demonstrating attainment of all federal and state ambient air quality standards for the district[2]. Furthermore, the SCAQMD must adopt rules and regulations that carry out the AQMP[3]. The ~~2003~~ 2007 AQMP concluded that major reductions in criteria pollutant emissions of volatile organic compounds (VOCs) and oxides of nitrogen (NOx) are necessary to attain the air quality standards for ozone, particulate matter with an aerodynamic diameter of 10 microns or less (PM10) and particulate matter with an aerodynamic diameter of 2.5 microns or less (PM2.5). Ozone, a criteria pollutant, is formed when VOCs react with NOx in the atmosphere and has been shown to adversely affect human health. VOC emissions also contribute to the formation of PM10 and PM2.5. The federal one-hour ozone standard was exceeded 35 times and the eight-hour ozone standard was exceeded 86 times in 2006 at various locations in the district. The state one-hour ozone standard was exceeded 102 times and the eight-hour ozone standard was exceeded 121 times in 2006. As a result, additional VOC reductions are necessary to attain the federal and state ozone standards.

Rule 1149 – Storage Tank Cleaning and Degassing, was originally adopted by the South Coast Air Quality Management District (SCAQMD) on December 4, 1987 and subsequently amended on April 1, 1988 and July 14, 1995.

Rule 1149 applies to VOC emissions from cleaning and degassing operations in large aboveground organic liquid storage tanks predominately at petroleum refineries and terminals and small underground organic liquid storage tanks. The current rule requires vapors contained in storage tanks to be vented to a control device for a pre-determined length of time or to be displaced by a liquid into a control device.

The proposed amended rule amendments would instead require a vapor concentration of 5,000 parts per million by volume (ppmv), measured as methane, to be met for at least one hour before allowing the vapors to be vented to atmosphere. This proposed standard will better capture emissions from sludge and product residual remaining in the tanks. Liquid balancing or any other technology that achieves the proposed standard will be allowed.

The proposed amended rule amendments would also expand the applicability of the rule to small above ground organic liquid storage tanks, pipelines and large storage tanks previously exempted because of lower vapor pressure products. Furthermore, the proposed amended rule will streamline the notification process and clarify requirements for vacuum trucks and containers used for storing liquid and sludge removed during the cleaning process.

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[1] The Lewis-Presley Air Quality Management Act, 1976 Cal. Stats., ch 324 (codified at Health & Safety Code, §§40400-40540).

[2] Health & Safety Code, §40460 (a).

[3] Health & Safety Code, §40440 (a).

If approved, the proposed amended rule amendments would fully implement control measure FUG-04 in the 2007 Air Quality Management Plan. As proposed, the rule would reduce VOC emissions by ~~1.25~~ 1.27 tons per day.

Many degassing operations routinely achieve in practice the proposed requirements set forth in the proposed amended rule. California Code of Regulations, Title 8 - General Industry Safety Orders, has strict restrictions for entry into confined spaces with hazardous atmospheres such as petroleum storage tanks. In order to avoid the Title 8 restrictions, many facility operators vent the vapors contained in the storage tanks into a control device, such as an internal combustion engine (ICE) or thermal oxidizer, until the tank interior is no longer considered a hazardous atmosphere, which would comply with the proposed amended rule requirements. Additionally, concern for nearby schools and residences as well as the potential for Rule 402 – Nuisance violations keeps facility operators from discharging odorous VOC emissions.

CALIFORNIA ENVIRONMENTAL QUALITY ACT

PAR 1149 is a discretionary action, which has potential for resulting in direct or indirect change to the environment and, therefore, is considered a "project" as defined by the California Environmental Quality Act (CEQA). SCAQMD is the lead agency for the proposed project and has prepared this ~~draft~~ Final Environmental Assessment (EA) with no significant adverse impacts pursuant to its Certified Regulatory Program. California Public Resources Code §21080.5 allows public agencies with regulatory programs to prepare a plan or other written document in lieu of an environmental impact report or negative declaration once the Secretary of the Resources Agency has certified the regulatory program. SCAQMD's regulatory program was certified by the Secretary of the Resources Agency on March 1, 1989, and is codified as SCAQMD Rule 110. Pursuant to Rule 110, SCAQMD has prepared this ~~draft~~ Final EA.

CEQA and Rule 110 require that potential adverse environmental impacts of proposed projects be evaluated and that feasible methods to reduce or avoid significant adverse environmental impacts of these projects be identified. To fulfill the purpose and intent of CEQA, the SCAQMD has prepared this ~~draft~~ Final EA to address the potential adverse environmental impacts associated with the proposed project. The ~~draft~~ Final EA is a public disclosure document intended to: (a) provide the lead agency, responsible agencies, decision makers and the general public with information on the environmental effects of the proposed project; and, (b) be used as a tool by decision makers to facilitate decision making on the proposed project.

SCAQMD's review of the proposed project shows that the proposed project would not have a significant adverse effect on the environment. Therefore, pursuant to CEQA Guidelines §15252, no alternatives or mitigation measures are required to be included in this ~~draft~~ Final EA. The analysis in Chapter 2 supports the conclusion of no significant adverse environmental impacts.

The Draft EA was released for a 30-day public review and comment period from March 11, 2008 to April 9, 2008. One comment letter was received from the public and is included with a response to the comment in Appendix D.

PROJECT LOCATION

PAR 1149 would affect commercial facilities located throughout the SCAQMD's jurisdiction. The SCAQMD has jurisdiction over an area of 10,473 square miles, consisting of the four-county South Coast Air Basin (Basin) and the Riverside County portions of the Salton Sea Air Basin (SSAB) and the Mojave Desert Air Basin (MDAB). The Basin, which is a subarea of the district, is bounded by the Pacific Ocean to the west and the San Gabriel, San Bernardino, and San Jacinto Mountains to the north and east. The 6,745 square-mile Basin includes all of Orange County and the non-desert portions of Los Angeles, Riverside, and San Bernardino counties. The Riverside County portion of the SSAB and MDAB is bounded by the San Jacinto Mountains in the west and spans eastward up to the Palo Verde Valley. The federal non-attainment area (known as the Coachella Valley Planning Area) is a subregion of both Riverside County and the SSAB and is bounded by the San Jacinto Mountains to the west and the eastern boundary of the Coachella Valley to the east (Figure 1-1).

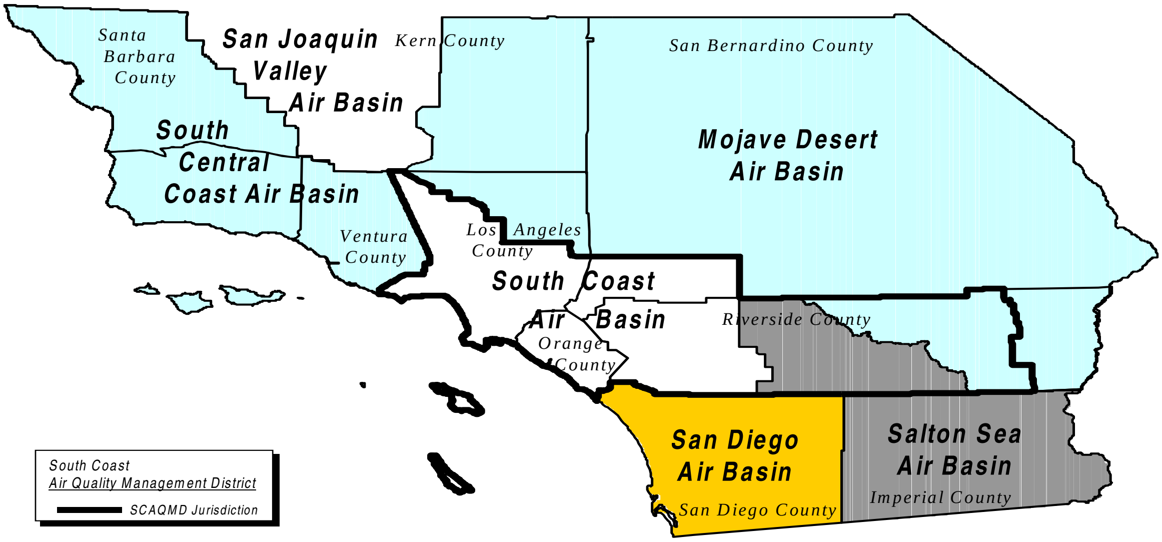

Figure 1-1
Boundaries of the South Coast Air Quality Management District

PROJECT OBJECTIVE

The objective of PAR 1149 is to implement the 2007 AQMP control measure FUG-04 – Further Emission Reductions from Pipeline and Storage Tank Degassing, to achieve additional VOC emission reductions. Additional VOC emissions reductions would assist the SCAQMD in efforts to attain and maintain with a margin of safety state and national ambient air quality standards for ozone, PM10 and PM 2.5.

PROJECT BACKGROUND

In 1987, Rule 1149 – Storage Tank Cleaning and Degassing, was adopted to reduce VOC emissions from degassing operations of stationary storage tanks. The Standard Industrial Classification codes applied to affected facilities include the following: crude petroleum and natural gas (SIC code 1311), paints, varnishes, lacquers, enamels, and allied products (SIC code 2851), cyclic organic crudes and intermediates, and organic dyes and pigments (SIC Code 2865), industrial organic chemicals, not elsewhere classified (SIC code 2869), petroleum refining (SIC code 2911), special warehousing and storage, not elsewhere classified (SIC code 4226), crude petroleum pipelines (SIC code 4612), refined petroleum pipelines (SIC code 4613), chemical and allied products, not elsewhere classified (SIC code 5169), petroleum bulk stations and terminals (SIC code 5171), and automotive dealers and gasoline service stations (SIC code 5541).

At the time of adoption, staff estimated that 800 floating roof tanks, 213 fixed roof tanks and 33,600 underground storage tanks (UST) located at petroleum refineries and terminals, chemical plants and gasoline stations would be subject to the rule. Based on each tank being degassed once every ten years, an estimated 0.4 ton per day was expected to be controlled from floating and fixed roof tanks and another 0.3 ton per day was expected to be controlled from USTs.

The premise of the VOC emission reductions anticipated for the rule has been a differential equation describing the change in concentration in the tank over time:

$$dC/dt + QC/V = 0 \qquad \text{Equation 1}$$

where dC/dt is the change in concentration in the tank over time, Q is the flow rate, C is the final concentration and V is the volume.

The solution to the equation:

$$C = Co\ e\text{-}(Qt/V) \qquad \text{Equation 2}$$

when the final concentration is 10 percent of the initial concentration, or $C = 0.1C_o$, gives:

$$0.1Co = Co\ e^{-(Qt/V)} \qquad \text{Equation 4}$$
$$\text{or } 0.1 = e^{-(Qt/V)} \qquad \text{Equation 5}$$

Thus theoretically, to get a 90 percent reduction in VOC emissions, then $t = 2.3V/Q$. Or in other words, if a tank were to be degassed to a control device for a period of time equal to 2.3 volume turnovers, 90 percent of the emissions would be controlled. The use of the equation makes a key assumption which is that the storage tank has no product or sludge remaining in the tank when the degassing begins.

On July 14, 1995, the rule was amended to remove ambiguities in rule language relating to business and regulatory practices. Specifically, the clarifications included alteration of notification procedures and confirming that USTs to be degassed must be controlled per PAR 1149 even if they are removed from the ground. The 1995 amendments to the rule also extended the application of the rule to storage tanks that were undergoing product changes by adding the term "cleaning" to the applicability of the rule. The 1995 amendments did not increase emissions nor were they determined to have a significant adverse impact on the environment.

The 1995 amendments updated Rule definitions and requirements to ensure consistency with the current degassing practices employed by complying businesses at that time.

Overview of Current Regulatory Requirements

In addition to Rule 1149 there are a number of related local, state and federal rules and regulations that also control VOC emissions from fossil fuels and related organic products. These rules and regulations are briefly summarized in the following subsections.

SCAQMD Requirements

Rule 402

Rule 402 – Nuisance, prohibits facilities from discharging odorous emission, including OC emissions that may cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public.

Rule 463

SCAQMD Rule 463 – Storage of Organic Liquids, specifies emptying and refilling procedures that occur just before and after degassing operations. For example, while a tank is being drained of product, Rule 463 would apply and require the draining to be continuous. Once draining is complete, Rule 1149 would apply until product is reintroduced into the tank at which point Rule 463 would once again apply. While there are no vapor concentration limits directly associated with emptying or refilling, Rule 463 does have a vapor leak limit of 1,000 ppmv, expressed as methane.

Rule 1178

Rule 1178 - Further Reductions of VOC Emissions from Storage Tanks at Petroleum Facilities applies to larger storage tanks at petroleum facilities and establishes additional control requirements and specifications to those included in Rule 463.

State Requirements

In California, the Office of the State Fire Marshall, Pipeline Safety Division regulates the safety of hazardous liquid transportation pipelines. The office inspects, tests and investigates to ensure compliance with state and federal pipeline safety laws. The state has provisions for maintaining pipelines and reporting and repairing leaks, but no provisions for controlling vapors from leaks or degassing operations.

Many pipeline degassing operations routinely achieve in practice the proposed requirements set forth in the proposed amended rule for safety reasons. California Code of Regulations, Title 8 - General Industry Safety Orders, has strict restrictions for entry into confined spaces with hazardous atmospheres such as petroleum storage tanks. In order to avoid the restrictions, many facility operators vent the vapors contained in the storage tanks into a control device until the tank interior is no longer considered a hazardous atmosphere, which would generally comply with the proposed amended rule requirements.

Federal Requirements

The Office of Pipeline Safety is the primary federal agency regulating pipelines. There are provisions for maintaining pipelines and reporting and repairing leaks, but no provisions for controlling vapors from leaks or degassing operations.

PROJECT DESCRIPTION

The following summarizes requirements and advisory provisions of the proposed amended rule. A copy of PAR 1149 is included in Appendix A.

Purpose and Applicability

The purpose was modified to specifically state that the rule is to reduce VOCs and toxic emissions from roof landings, cleaning, maintenance, testing, repair and removal of storage tanks and pipelines. Cleaning and degassing of pipelines opened to the atmosphere outside the boundaries of a facility has been added to applicability of the proposed amended rule. A statement that the applicability of the rule to tanks commences once the tank is emptied is included.

Definitions of Terms

New definitions for drain-dry breakout tank, facility, natural gas, Reid vapor pressure~~, true vapor pressure~~ and vapor tight condition were added. The definition for underground storage tank was removed. The limits for underground storage tanks were previously different and thus necessitated defining the difference between the tanks. The limits are now the same and differentiation is no longer necessary. The definition of vapor leak was reduced from a detection of VOC compounds in excess of 10,000 parts per million volume (ppmv) to 5,000 ppmv. Specific source test methodology was also removed from the definition of vapor leak. The definition of VOC was replaced with a reference to the definition in Rule 102.

Requirements

- Remove time and equipment requirements in paragraphs (c)(5) and (c)(6) and replace with a vapor concentration requirement of 5,000 ppmv, measured as methane. The concentration must be met for at least one hour after degassing has been completed. This will prevent tanks with excess product residual or sludge from being opened prematurely. The proposed vapor concentration standard conservatively translates to a ten percent LEL already met by many degassing operations. The vapor concentration standard will capture the majority of emissions created by product residual and sludge. Any technique, including liquid displacement, is allowed as long as any vapor displaced is routed to an approved vapor recovery system and the vapor concentration standard is met. In most instances, companies will utilize the same techniques currently in use but be required to do so for a longer period of time. However, new innovations and processes may be developed to meet the proposed standard. By establishing a standard as opposed to one or more control techniques, the rule provides flexibility to industry to apply technological advances.
- Extend the applicability of the rule to pipeline and to more above ground storage tanks (see Table 1-1).

Table 1-1
Proposed Changes to Storage Tank Applicability

Vapor Pressure	Typical Products	Current (gallons)	Proposed (gallons)
3.9 psi RVP	Gasoline	19,815	500
2.6 psi RVP	Crude	39,630	26,420
0.1 psi TVP	Kerosene	N/A	100,000

- Lower the VOC vapor concentration of a Vapor Leak from 10,000 ppmv to 5,000 ppmv. This will make the Vapor Leak standard consistent with the vapor concentration standard. It will require all the hoses, fittings and connections to meet the same standard the tank or pipeline is required to meet. It differs from the requirements of "Vapor Tight" in Rule 463 (1,000 ppmv) and Rule 1178 (500 ppmv) because product and residual is being removed from the tank or pipeline instead of "stored" to which Rule 463 applies. The proposed amended rule would also remove the test method from the definition and place it in the Test Methods section. The test method will include directions for distance and/or placement of the probe inlet. For storage tanks, the probe inlet shall be one foot above the bottom or sludge. ~~Cylindrical tanks must be monitored at least two feet from the inner surface of the wall. Pipelines shall be monitored one foot or more from the pipeline.~~ All monitoring measurements are to be recorded and maintained to verify compliance with the vapor concentration standards.
- Require floating roofs that rest on support legs to be free of vapors, vented to a control device or, as an additional compliance option for drain-dry breakout tanks, be maintained in a vapor tight condition of 500 ppmv measured as methane. A compliance schedule is included for drain-dray breakout tanks that must be modified to meet the compliance option. Monitoring would be required monthly and records for monitoring results shall be maintained to verify compliance. While the roof rests on its support legs, the seals may lose effectiveness and fugitive emissions may occur. Roof landings may occur during product changes crude oil is received from overseas and when products are sold from one company to another. This will address a common situation and codifies an enforcement policy. Definitions for "Drain-Dry Breakout Tank" and "Vapor Tight Condition" will be included.
- Require vacuum trucks that remove product residual and sludge from pipeline and storage tanks subject to the rule to exhaust vapors into a control device. Vacuum trucks are not designed to store vapors or control vapors themselves. When vacuum trucks pump product into their tanks, vapors are created and may escape to the atmosphere if not properly controlled.
- Limit the exhaust concentration of control devices used to 500 ppmv, measured as methane. In many cases the vapor concentration in a tank can be greater than 100,000 ppmv. Ninety percent control would allow 10,000 ppmv to escape and even 99 percent control would allow 1,000 ppmv to escape. This will set a stringent, yet achievable standard that is consistent with other SCAQMD rules.
- Require that product residual and sludge taken from pipeline and storage tanks subject to the rule is stored or disposed into closed containers or control systems free of liquid and vapor leaks. This will reduce emissions that might occur while the waste material is waiting further processing. Prior to the completion of degassing operations, all waste shall be disposed or stored in closed containers or control systems. An exception will be included for draining

liquid from pipeline as long as the draining is continuous and the liquid is immediately transferred into a closed container. This will accommodate field repair of pipeline where draining into closed containers may lead to spillage and soil contamination. Once degassing has been completed per the proposed amended rule requirements, any remaining sludge should be mostly VOC free and can be transferred into storage bins or other appropriate waste containers. However, vacuum trucks used to collect liquid and/or sludge from tanks and pipelines subject to this rule must continue to limit their exhaust to 500 ppmv, measured as methane.

- Eliminate the emergency notification requirements and shorten the notification period and duration as well as eliminating the need for authorization. The notification procedure will be streamlined requiring between two hours and two days notification before degassing takes place. It is common currently to have several duplicate notifications for a single degassing event. In addition, emergency degassing operations are delayed while waiting for the emergency to be approved by an authorized agency officer allowing uncontrolled VOC emissions into the atmosphere. Most emergency situations will take longer than two hours to get degassing equipment on-site. In the rare instance where an emergency occurs and degassing equipment is available in less than two hours, the facility may utilize Rule 430 – Breakdown Provisions. The new notification procedures will allow more flexibility to affected sources and improve the accuracy of the notifications.
- Add a definition for Natural Gas and exempt natural gas pipeline from the provisions of the rule. Natural gas is comprised mostly of methane which is not considered VOC.
- Include a quantification protocol for voluntary greenhouse gas reductions. The provision in PAR 1149 is voluntary and limited to the control of methane emissions from the degassing of natural gas pipelines, which is currently exempt from the requirements of the rule. Efforts to limit methane emissions from natural gas pipeline repair and maintenance activities would allow companies to reduce greenhouse gas emissions. The quantification protocol calculation methodology standardizes the quantification of the reductions but is general enough to allow innovative techniques as they are developed.
- Test methods for determining True Vapor Pressure are included.

Exemptions

- Exempt small diameter pipeline and small lengths of pipeline depending on the vapor pressure of the liquid it previously contained. The pipeline exemptions are based on the exemptions for storage tanks with similar volumes. Thus a 500 gallon organic liquid storage tank is roughly equivalent to a 100 foot length of pipeline containing organic liquid. Similarly, 0.25 miles of organic liquid pipeline is roughly equivalent to a 26,420 gallon organic liquid storage tank.
- Remove the exemption for storage tanks exempted in Health and Safety Code Section 25281. Most of the tanks exempted under Health and Safety Code Section 25281 will not be subject to the proposed amended rule because they contain low vapor pressure products. However, gasoline tanks on farms with capacities greater than 500 gallons would now be subject to this rule. Gasoline tanks on farms with capacities greater than 1,100 gallons were already subject to the rule.
- Include an exemption when tanks and pipelines are opened to connect or disconnect degassing equipment, sample emissions, purging inert gas from pipelines when reintroducing product or to connect or disconnect the pipeline including associated control techniques or

control equipment. In the case of pipelines, the only access will likely be the opening directly where the pipeline is disconnected. During the process of opening the pipeline, the operation will be exempt. However, once the pipeline is open, measures must be taken to limit vapor emissions. Such measures may include, but are not limited to, blinding the pipeline, blocking with mud plugs or putting dry ice in the pipeline. Once the repair or maintenance activity is concluded, the vapor control measure may need to be removed to allow product flow. During the removal of the vapor control measure and subsequent reconnection of the pipeline, the rule will not apply.

EMISSIONS INVENTORY

The original emission inventory generated in 1987 estimated that uncontrolled emissions subject to Rule 1149 were 1.26 tons per day. Above ground storage tanks (AST) accounted for 0.5 ton per day while USTs accounted for the remainder. Based on the theoretical reduction from degassing over 2.3 air exchanges, the rule was expected to reduce emissions by 0.7 ton per day, with 0.4 tons per day being reduced from ASTs. The 1995 rule amendment made some new assumptions regarding how to calculate UST emissions but did not change the uncontrolled or expected emission reductions.

Over the 18 years since the initial emission inventory was generated, tank types, capacities and frequency of degassing incidents have changed. Initially, all tanks were assumed to be degassed once every 10 years and estimates were made to calculate the volume required to be degassed. The initial emission inventory was based on floating roof tanks having 56,991 cubic feet to be degassed. The average fixed-roof tank degassed had a volume of 125,214 cubic feet to degas. 101 tanks would be degassed each year (80 floating and 21 fixed). Assuming complete saturation of gasoline or crude oil, this accumulates to 0.5 ton of VOC per day.

Notification provisions in the rule have provided SCAQMD with detailed information including location, tank capacity and tank contents. Except in the relatively uncommon situation where a tank is degassed using liquid displacement, each time a tank is to be degassed by the facility or by a third party contractor, the degasser will notify SCAQMD. With this information, staff has been able to refine the estimates of the volume, contents degassed and frequency of degassing events. Most importantly, the notification data shows that the ASTs are degassed at more than three times the frequency predicted. While most ASTs still are degassed every ten years or so for periodic repair and maintenance activities, some ASTs are degassed on a weekly basis because they are used primarily for product changes.

A limitation, however, is the lack of information regarding whether the AST was a floating roof or fixed roof type. This is important because for equal capacity tanks, the volume degassed in a floating roof tank is approximately one tenth that of a fixed roof tank. For example, a typical tank height is approximately 60 feet. It would be necessary to degas the entire 60 feet of a fixed roof tank while a floating roof tank would only need to degas about six feet of space. Staff conducted an assessment to determine the frequency of degassing when comparing floating versus fixed roof tanks. Industry was consulted, staff made site visits and compared notifications with tank rosters. It is estimated that 90 percent of all AST degassing operations are for floating roof tanks.

Table 1-2 summarizes the notification data submitted to SCAQMD between 2004 and 2006.

Table 1-2
Notification Data Summary

Above Ground Storage Tanks	**2004**	**2005**	**2006**	**3-Year Average**
Number of AST degassed	295	268	421	328
Ave capacity AST (cubic feet)	765,335	732,731	720,202	739,422
Total volume degassed (million cubic feet)	44.7	38.9	60.0	47.9
Total uncontrolled emissions (tpd)	1.7	1.4	3.1	2.1

The summary data shows that an average of 328 ASTs with an average capacity of 739,422 cubic feet were degassed annually. The volume was calculated by using the volume reported and assuming that only 10 percent of the tanks were fixed and would degas the entire volume. For the remaining 90 percent of the ASTs, only about one-tenth of the volume reported would require degassing. This is because the roof of the floating roof tanks “floats” on the liquid in the tank until the tank liquid level is lower than the support legs which are generally about 6 feet tall. Using the ideal gas law methodology, the uncontrolled average annual emission inventory estimate from ASTs would be 2.1 tons per day. The vapor pressure and molecular weight were determined from the product in the tank. The ideal gas law methodology assumes that complete saturation has had time to occur and that there are no additional sources of emissions. It is calculated as follows:

$$E = (VP / 14.7 \text{ psia}) * (MW / 379 \text{ ft}^3) * V$$

Where

E = emissions, lb
VP = vapor pressure, psia
14.7 psia is atmospheric pressure under standard conditions
MW = molecular weight, lb/lb-mole
379 ft^3 is the standard cubic feet per lb-mole at standard conditions
V = volume, cubic feet

However, the actual saturation rate depends on a variety of factors including temperature, agitation and time. For example, a completely filled fixed roof gasoline tank quickly drained would have a lower saturation rate compared to the same tank that was near empty when drained. Another factor complicating the ideal gas law methodology is sludge and product residue remaining in the tank when degassing commences. Additional hydrocarbon vapors are released from the sludge and residue while the tank is degassed.

In order to get a clearer picture of actual emissions being generated from tank degassing operations, 56 degassing logs were reviewed. The logs indicate that there are fewer emissions in the storage tanks than the ideal gas law methodology would suggest. The actual emissions coming from tank degassing are 69 percent of the expected emissions using the ideal gas methodology. While most tanks have initial vapor concentrations greater than 100 percent LEL (roughly 50,000 ppmv, measured as methane), this is well below complete saturation. A possible explanation is that the tanks are drained faster than the liquid can evaporate. Once drained, degassing operations take place sooner than sludge and product residual can saturate the vapor space. Thus where the ideal gas law methodology would expect complete saturation, only partial saturation is seen. There may also be some unquantifiable loss when the contents of the tank are being pumped out of the tank. Vapor may be inadvertently removed if some part of the vacuum hose is above the liquid level.

Additionally, the degassing logs show that sludge and product residual significantly contribute to the emissions emanating from the storage tanks. A tank with partial saturation should be able to degas in a shorter time period than a completely saturated tank. However, the logs indicate that degassing actually takes a much longer time. On average, it takes two to three times longer because product residual and sludge continue to release vapors into the tank being degassed.

In the example provided in Table 1-3, a sample degassing log is examined. A floating roof gasoline tank with a vapor space of 7,921 cubic feet (59,249 gallons) is to be degassed. To comply with the current regulation, the company must degas at least 18,218 cubic feet of volume. The initial inlet concentration (150 percent LEL) is well below complete saturation used for an ideal gas calculation (approximately 600 percent LEL). After just over two hours, 2.3 air exchanges has been surpassed with an associated 149 pounds of VOC reduced. However, at least that much more remains in the tank and is not controlled until the inlet concentration is reduced below ten percent LEL. In the example tank, the emission reduction at 2.3 air exchanges is approximately 40 percent and the actual emissions are about 74 percent of the expected emissions.

Closer examination of individual tank logs reveals a wide variation in the actual emissions degassed from the tank. Some tanks have emissions much lower than expected suggesting a tank relatively free of sludge and product residual that was full to begin with and drained quickly. Others have emissions greater than expected probably because there was a larger vapor space that had time to reach equilibrium and/or significant amounts of sludge and product residual that continued to evaporate while the tank was being degassed. Theoretically, 2.3 air exchanges should reduce emission by 90 percent but the logs indicate an actual reduction rate of only 37 percent.

Using the notification data information and comparing the ratios of expected versus actual and expected versus 2.3 air exchanges we can determine how many pounds of emission can be captured by adopting a vapor concentration standard and comparing it to amount of emissions captured by the current standard of 2.3 air exchanges (see Table 1-4).

Comparing the two methods to calculate emission inventory shows that the there is a smaller overall inventory using emissions from degassing logs. However, more emissions reductions can be realized by further restrictions in the rule, particularly by the establishment of a vapor concentration standard.

In addition to the already regulated ASTs and USTs, the proposed rule amendment would lower the tank capacity and vapor pressures subject to the regulation. ASTs of capacities of 500 gallons or greater containing gasoline would be subject to the rule. The 100,000 liter (26,420 gallon) tanks or greater containing crude oil or other products with Reid vapor pressure greater than 134 mm Hg (2.6 psi) would now be subject to the rule. And any tank larger than 378,500 liters (100,000 gallons) containing a product with a Reid vapor pressure greater than five mm Hg (0.1 psia) would be subject to Rule 1149.

Survey data and tank rosters provided by major refiners indicate that approximately 470 new tanks would be subject to the rule. The average capacity of the newly applicable tanks reported by the refiners is 2.5 million gallons. The average of the newly applicable tanks at terminals and other locations is 2.2 million gallons. The overall average for newly applicable tanks is 2.3 million gallons. In comparison, the average size of already applicable tanks is 5.5 million gallons or nearly double the volume of the newly applicable tanks.

Table 1-3
Degassing Log Example

Gasoline Tank Example **Volume to be Degassed: 7921 cubic feet** **Expected Emissions: 502 pounds of VOC**					
Time	**Flow from tank (cfm)**	**Cumulative Volume (cubic feet)**	**Inlet Concentration (% LEL)**	**Hourly emissions (pounds)**	**Cumulative Emissions (pounds)**
1345	100	0	150	0.0	0.0
1400	200	1,500	125	5.7	5.7
1500	700	13,500	100	37.7	43.3
1600	800	55,500*	76	105.5	148.8
1700	1,000	103,500	48	91.6	240.5
1800	1,000	163,500	21	72.3	312.8
1900	2,100	223,500	9	31.6	344.5
2000	2,100	349,500	7	28.5	372.9

*2.3 Air Exchanges Surpassed

Expected	**2.3 Air Exchanges**	**Actual**
502.0	148.8	372.9

Table 1-4
Emission Inventory Comparison

Description	Uncontrolled	2.3 Air Turnovers	Remaining
Total emissions using ideal gas law (tpd)	2.1	1.9	0.2
Total emissions from degassing logs (tpd)	1.42	0.5	0.92

Using the actual tank capacities and product contents from those refiners who provided the survey data, the average uncontrolled degassing emission from a newly applicable tank is 2,370 pounds of VOC. Applying the same correction factor of actual versus expected emissions (0.685) seen from the degassing logs summarized in Table 3, there would be 1,620 pounds of uncontrolled emission from degassing each newly applicable tank. Conservatively assuming that the tanks are degassed once every ten years, the annual uncontrolled emissions from newly applicable tanks would be 76,140 pounds (0.1 ton per day).

Aside from storage tanks, pipelines containing organic liquid would also be subject to the rule. According to the California Office of the State Fire Marshall, there are 7,500 miles (approximately 4,000 miles in the South Coast Air Basin) of hazardous liquid transportation pipeline within the state. California laws mandate that each pipeline system be tested at least every five years. Testing usually consists of hydrotesting or use of internal inspection tools sometimes known as “smart pigs”. Most pipeline inspection and repair activities already vent vapors to an uncontrolled vacuum truck. The result is 4.2 million cubic feet annually of gasoline or crude oil vapor could be released to the atmosphere. The proposed amended rule would apply to pipelines outside of permitted facilities that were six inches or greater in diameter. Pipelines shorter than 100 feet in length are exempt as are pipelines shorter than 0.25 mile containing or previously containing VOC liquids having a Reid vapor pressure less than 202 mm Hg. Staff estimates the addition of pipelines to the proposed amended rule adds 0.4 ton per day to the emission inventory.

In the 1987 rule underground storage tanks (USTs) originally contributed 0.63 tons per day to the uncontrolled emission inventory and the rule was expected to reduce 0.3 ton per day. In 1995, the staff report indicated that the number of USTs had decreased by 70 percent. However, emission calculations in the 1995 Final Staff Report for Proposed Amended Rule 1149 – Storage Tank Degassing show that the emission reductions remained the same because emissions from USTs were higher than originally estimated and industry practices now reduced emissions by 99 percent. Over the past three years, an average of 501 USTs were degassed with an average capacity of 11,346 gallons. The uncontrolled emissions from USTs were 0.07 ton per day calculated by adjusting the number of tanks and average volume in comparison to estimates made in previous staff reports. Using the 99 percent control efficiency claimed by the 1995 rule amendment, the emission reduction from USTs were also 0.07 tons per day. No emission reductions from USTs are claimed in this proposed amendment. In summary, the total uncontrolled emissions from all sources subject to the proposed amendments to Rule 1149 is 1.99~~7~~ tons per day with 0.57 ton per day controlled by existing regulations (see Table 1-5). Therefore the remaining emission inventory to be further regulated by the proposed amendments to Rule 1149 is 1.42 tons per day of VOC.

Table 1-5
Emission Inventory from All Rule 1149 Sources

Source	**Emissions Inventory Before Control**	**Emissions Controlled by Existing Rule 1149**	**Remaining Emissions Inventory**
ASTs currently subject to rule (tpd)	1.42	0.5	0.92
USTs (tpd)	0.07	0.07	0
Newly applicable ASTs (tpd)	0.1	0	0.1
Pipelines (tpd)	0.4	0	0.4
Total emissions from all Rule 1149 Sources (tpd)	**1.99~~7~~**	**0.57**	**1.42**

CHAPTER 2 - ENVIRONMENTAL CHECKLIST

Introduction

General Information

Environmental Factors Potentially Affected

Determination

Environmental Checklist and Discussion

INTRODUCTION

The environmental checklist provides a standard evaluation tool to identify a project's potential adverse environmental impacts. This checklist identifies and evaluates potential adverse environmental impacts that may be created by the proposed project.

GENERAL INFORMATION

Project Title:	Proposed Amended Rule (PAR) 1149 – Storage Tank and Pipeline Cleaning and Degassing
Lead Agency Name:	South Coast Air Quality Management District
Lead Agency Address:	21865 Copley Drive Diamond Bar, CA 91765
CEQA Contact Person:	Mr. James Koizumi (909) 396-3234
Rule Contact Person	Mr. Michael Morris (909) 396-3282
Project Sponsor's Name:	South Coast Air Quality Management District
Project Sponsor's Address:	21865 Copley Drive Diamond Bar, CA 91765
General Plan Designation:	Not applicable
Zoning:	Not applicable
Description of Project:	PAR 1149 would implement the 2007 AQMP control measure FUG-04 – Further Emission Reductions from Pipeline and Storage Tank Degassing, to achieve additional VOC emission reductions. PAR 1149 would extend the applicability of the rule to small above ground organic liquid storage tanks, pipelines, and large storage tanks previously exempted because of lower vapor pressure products. The current rule requires vapors contained in storage tanks to be vented to a control device for a pre-determined length of time or to be displaced by a liquid into a control device. PAR 1149 would instead require a vapor concentration of 5,000 ppmv, measured as methane, before vapors are vented to atmosphere. PAR 1149 would streamline the notification process and clarify requirements for vacuum trucks and containers used for storing liquid and sludge removed during the cleaning process. PAR 1149 introduces a greenhouse gas (GHG) quantification protocol, where GHG emissions may be voluntarily reduced by controlling methane emissions from natural gas pipelines.
Surrounding Land Uses and Setting:	Not applicable
Other Public Agencies Whose Approval is Required:	Not applicable

ENVIRONMENTAL FACTORS POTENTIALLY AFFECTED

The following environmental impact areas have been assessed to determine their potential to be affected by the proposed project. As indicated by the checklist on the following pages, environmental topics marked with an "✓" may be adversely affected by the proposed project. An explanation relative to the determination of impacts can be found following the checklist for each area.

☐ Aesthetics
☐ Biological Resources
☐ Geology/Soils
☐ Land Use/Planning
☐ Population/Housing
☑ Solid/Hazardous Waste
☐ Agriculture Resources
☐ Cultural Resources
☑ Hazards & Hazardous Materials
☐ Mineral Resources
☐ Public Services
☐ Transportation/ Traffic
☑ Air Quality
☑ Energy
☐ Hydrology/ Water Quality
☑ Noise
☐ Recreation
☑ Mandatory Findings of Significance

DETERMINATION

On the basis of this initial evaluation:

☑ I find the proposed project, in accordance with those findings made pursuant to CEQA Guideline §15252, COULD NOT have a significant effect on the environment, and that an ENVIRONMENTAL ASSESSMENT with no significant impacts will be prepared.

☐ I find that although the proposed project could have a significant effect on the environment, there will NOT be significant effects in this case because revisions in the project have been made by or agreed to by the project proponent. An ENVIRONMENTAL ASSESSMENT with no significant impacts will be prepared.

☐ I find that the proposed project MAY have a significant effect(s) on the environment, and an ENVIRONMENTAL ASSESSMENT will be prepared.

☐ I find that the proposed project MAY have a "potentially significant impact" on the environment, but at least one effect 1) has been adequately analyzed in an earlier document pursuant to applicable legal standards, and 2) has been addressed by mitigation measures based on the earlier analysis as described on attached sheets. An ENVIRONMENTAL ASSESSMENT is required, but it must analyze only the effects that remain to be addressed.

☐ I find that although the proposed project could have a significant effect on the environment, because all potentially significant effects (a) have been analyzed adequately in an earlier ENVIRONMENTAL ASSESSMENT pursuant to applicable standards, and (b) have been avoided or mitigated pursuant to that earlier ENVIRONMENTAL ASSESSMENT, including revisions or mitigation measures that are imposed upon the proposed project, nothing further is required.

Date: March 7, 2008 **Signature:** Steve Smith

Steve Smith, Ph.D.
Program Supervisor

ENVIRONMENTAL CHECKLIST AND DISCUSSION

The proposed project would expand the applicability of the rule to small above-ground organic liquid storage tanks, pipeline with capacities of 500 gallons or more and all above ground storage tanks with capacities of 100,000 gallons or more or previously containing VOC product with vapor pressures greater than five millimeters of mercury. PAR 1149 would replace the 90 percent control device efficiency with a limit on the exhaust concentration of control devices to 500 parts per million (ppm) vapor, measured as methane. PAR 1149 would replace time and equipment requirements with a vapor concentration standard of 5,000 ppm, measured as methane; streamline notification procedures; require the control of exhaust vapors from vacuum trucks associate with product residual and sludge from pipeline and storage tanks; lower the VOC vapor concentration of a vapor leak from 10,000 ppm to 5,000 ppm; and require that floating roof tanks that are emptied for product changes to degas or the VOC concentration is reduced to less than 5,000 ppmv while the floating roof rests on its support legs, unless it is a drain-dry internal floating roof breakout tank maintained in a vapor tight condition outside the tank shell and monitored monthly. PAR 1149 introduces a greenhouse gas (GHG) quantification protocol, where GHG emission may be reduced by controlling methane emissions from natural gas pipelines.

Degassing Storage Tanks

The degassing process consists of several procedures intended to leave the tank free of product, sludge and vapors. The bulk of the product in the tank, if any, is pumped into another tank. A vacuum truck then sucks out the residual product. At this point the tank is largely free of liquid but may contain a relatively small amount of liquid, some sludge and is filled with vapors. Depending on the amount of sludge, the tank may be cleaned and rinsed before degassing (purging the gas) begins. Purging the gas is generally done by sucking the vapors out of the tank or displaced with a lower vapor pressure product. Because of the provisions in Rule 1149, the vapors purged are vented to a control device or vapor recovery system. These controls devices are typically portable engines or thermal oxidizers that combust the vapors as fuel. Because the vapor concentration may fluctuate substantially during the process, propane is used as an auxiliary fuel to ensure that enough fuel is available to maintain combustion at all times.

Other techniques used to control vapors from storage tanks include liquid balancing and water or chemical washing or rinsing. Liquid balancing consists of draining the tank until just prior to the floating roof resting on its support legs. The tank is then filled with a low vapor pressure liquid, allowing the chemicals to mix, and repeating until the desired vapor pressure of the liquid blend is reached. Because there is no vapor space created during the mixing process, no vapors are created. When the tank is finally completely drained, only vapors from the low vapor pressure liquid are created.

Water or chemical washing or rinsing cleans the tank of product and residual sludge thus diminishing the amount of VOC vapor concentration in the tank. The storage tank remains closed or air tight during the cleaning process. Water or a chemical is added to the tanks, sometimes with a high pressure jet. The sludge created is pumped out and, at a minimum, further emissions from sludge and product residual will be minimized. Once the tank has been degassed, the tank will be opened to ventilate the remaining vapors. This ventilation can be done by opening a vent and pulling fresh air into the tank or using a blower to force the vapors out of the tank. There may be a final cleaning and rinsing step to remove any last remnants of sludge.

Degassing Pipelines

Proposed Amended Rule 1149 will require that vapors from pipelines be controlled such that less than 5,000 ppmv measured as methane be emitted to the atmosphere. In trying to limit emissions, pipeline operators have several options available to them. Possible control measures include blinding or blocking the opening of a pipeline with a physical barrier such as a "pig", mud plug or valve, a chemical or gaseous barrier such as dry ice, nitrogen or diesel, or venting vapors to a control device such as carbon adsorption, thermal oxidizer or internal combustion engine.

Physical barriers would be the least expensive and mostly likely used option. Very little equipment or supplies are involved and there is only a small amount of labor involved. Chemical and gaseous barriers are also relatively inexpensive. Chemical and gaseous barriers require some amount of supplies. Filling a shorter length of pipeline with nitrogen remains cost-effective though filling a large length of pipeline (several miles) with nitrogen would be the most expensive option overall. There is also some waste that must be disposed of as well. However, in general, the most expensive option would be to vent vapors to a control device. The labor involved is usually the greatest and specialized equipment is needed.

To get a better understanding of current practice and plans being made to meet the proposed requirements, the two largest pipeline operators, and several refinery pipeline companies were contacted. Altogether, they represent approximately 90 percent of pipeline ownership in the South Coast Air Basin. In all cases, the work area where maintenance and repair activities took place was maintained at a vapor concentration below 10 percent of the LEL.

Under existing practices the companies have no control of fugitive emissions beyond work areas, purge pipelines with nitrogen, displace gasoline or crude vapors with diesel fuel, or plug lines with mud plugs or dry ice. One company always uses ICE engines or thermal oxidizers except when receptors are several miles away from the site.

The largest two companies would use carbon adsorption, when necessary. Neither would use ICEs or thermal oxidizers. One company would investigate increased use of pigging or dry ice. They may use carbon adsorption, but are not planning to use ICE or thermal oxidizers. The company that does use ICE or thermal oxidizers for areas would continue the existing practice, so there would be no change caused by PAR 1149.

The 10 percent of pipeline owners/operators that were not contacted have comparatively shorter pipelines. It is believed that these owners/operators would operate similar to the large pipeline owners/operators. Since the ICE/thermal oxidizer option is the most expensive and labor intensive option, it is believed that the smaller pipeline owners/operators would not choose this option.

Greenhouse Gas Reduction Quantification Program

There is an increasing need to provide a valid, regional credit mechanism for global warming gases in the South Coast Air Basin. The SCAQMD Governing Board has proposed creation of a voluntary carbon-reduction credit program, to be called the SoCal Climate Solutions Exchange. This program, to be developed in the near future in a separate rule making activity, will incentivize cost-effective emission controls. The applicability, use, recordkeeping, issuance and all other aspects of the carbon-reduction credit will be addressed when the SoCal Climate Solutions Exchange program is developed.

The purpose of Rule 1149 is to reduce VOC emissions from storage tank and pipeline degassing operations. Methane, a VOC exempt compound, is present in natural gas pipelines. The proposed amended rule will include a quantification protocol for companies who voluntarily control methane emissions from natural gas pipelines. While methane is not a VOC, it is a global warming gas with a global warming potential more than 21 times that of CO2.

Methane losses from natural gas pipelines mainly occur during maintenance and repairs. Because of the vital nature of this utility, maintenance and repairs must be accomplished as rapidly as possible. When a situation arises requiring the pipelines to be opened to atmosphere, the pipeline is closed at nearby locations on either side of the opening. The gas in the pipelines is allowed to blowdown or be purged from the pipeline. The repair or maintenance work is completed and the pipeline is reopened allowing the natural gas to flow once again.

The most straightforward technique to minimize methane emissions is to minimize the length of pipeline that will be opened to atmosphere. Automated valves located several miles apart would be closed to isolate the area. Then manual valves located closer to the source could be closed to minimize the amount of blowdown gas that would otherwise be released. Other reductions might be possible from bleeding off the gas to a storage container or control device. If a combustion process is utilized, the carbon reduction would be reduced by four percent to reflect the subsequent release of CO2 created from burning the methane. Any supplemental fuel required for combustion is also subtracted from carbon reductions as it too is combusted into CO2. It is intended that the non-proscriptive calculation provided in PAR 1149 will provide an incentive to develop innovative techniques to minimize methane emissions. The global warming potential (GWP) for methane is taken from the International Panel on Climate Change (IPCC) Second Assessment Report. In the report, the IPCC established a GWP (100 years) for methane of 21 carbon dioxide equivalent units.

The quantification protocol calculation methodology standardizes the quantification of the reductions but is general enough to allow innovative techniques as they are developed. The review process gives the SCAQMD the opportunity to assess the activity to validate the process and quantify excess reductions.

	Potentially Significant Impact	Less Than Significant Impact	No Impact
I. AESTHETICS. Would the project:			
a) Have a substantial adverse effect on a scenic vista?	☐	☐	☑
b) Substantially damage scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings within a state scenic highway?	☐	☐	☑
c) Substantially degrade the existing visual character or quality of the site and its surroundings?	☐	☐	☑
d) Create a new source of substantial light or glare which would adversely affect day or nighttime views in the area?	☐	☐	☑

Significance Criteria

The proposed project impacts on aesthetics will be considered significant if:

- The project will block views from a scenic highway or corridor.
- The project will adversely affect the visual continuity of the surrounding area.
- The impacts on light and glare will be considered significant if the project adds lighting which would add glare to residential areas or sensitive receptors.

Discussion

I.a), b), c) & d) The major requirements of PAR 1149 would be the expansion of the applicability of the rule to above-ground organic liquid storage tanks, pipeline and large above ground storage tanks previously exempted by vapor pressure and more stringent control requirements. The result of these new requirements would be pipelines and more tanks would require degassing procedures that would require vapor recovery for vacuum trucks and venting purged vapors from the tanks or pipelines to control devices or vapor recovery systems. Other techniques such as liquid balancing and water or chemical washing or rinsing may be employed.

PAR 1149 is not expected to require any new ~~construction or~~ development. PAR 1149 would require minor construction to 14 drain dry breakout tanks. All construction would occur within the breakout tanks, so adverse construction impacts to aesthetics are not expected. Facility operators are likely to use portable control devices at new and existing sources. The portable control devices are for newly captured tanks may be ICEs or thermal oxidizers. Existing storage tanks are typically controlled by ICEs or thermal oxidizers. Degassing operators are expected to be limited to two days on average. Affected facilities are expected to be industrial facilities in industrial areas. The addition of pump trucks, portable ICEs or thermal oxidizers or washing equipment is not expected to appear substantially different than the delivery and transport trucks, and operation and maintenance activities. In addition, storage tanks are typically place in areas that are protected by fences or walls to prevent tampering or vandalism.

Pipelines are expected to be controlled by carbon adsorption. Pipelines may be in open areas, but activities associated with PAR 1149 are not expected to be substantially visibly different than other operational and maintenance activities. Therefore, the proposed project is not expected to block views from scenic highways or corridors or affect the visual continuity of the surrounding area.

Additional light or glare would not be created which would adversely affect day or nighttime views in the area. Portable ICEs and washing equipment is unlikely to generate light. A glow may be generated by thermal oxidizing units, but is not expected to generate a glare or to be extremely bright. Vapor degassing is expected to be completed during daylight hours.

Based upon these considerations, significant adverse aesthetics impacts are not anticipated and will not be further analyzed in this ~~Draft~~ Final EA. Since no significant aesthetics impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	**Less Than Significant Impact**	**No Impact**
II. AGRICULTURE RESOURCES. Would the project:			
a) Convert Prime Farmland, Unique Farmland, or Farmland of Statewide Importance (Farmland), as shown on the maps prepared pursuant to the Farmland mapping and Monitoring Program of the California Resources Agency, to non-agricultural use?	☐	☐	☑
b) Conflict with existing zoning for agricultural use, or a Williamson Act contract?	☐	☐	☑
c) Involve other changes in the existing environment which, due to their location or nature, could result in conversion of Farmland, to non-agricultural use?	☐	☐	☑

Significance Criteria

Project-related impacts on agricultural resources will be considered significant if any of the following conditions are met:

- The proposed project conflicts with existing zoning or agricultural use or Williamson Act contracts.
- The proposed project will convert prime farmland, unique farmland or farmland of statewide importance as shown on the maps prepared pursuant to the farmland mapping and monitoring program of the California Resources Agency, to non-agricultural use.
- The proposed project would involve changes in the existing environment, which due to their location or nature, could result in conversion of farmland to non-agricultural uses.

II. a), b), & c) PAR 1149 would reduce VOC emissions from storage tanks and pipelines during cleaning and degassing. PAR 1149 would not require any new development ~~or modifications to existing buildings or other structures to comply with the proposed amended rule~~. PAR 1149 would require minor construction (shortening of support legs) to 14 drain dry breakout tanks. All construction would occur within the breakout tanks, so adverse construction impacts to agricultural resources are not expected. All PAR 1149 activities are expected to occur within the boundaries of existing facilities or along existing pipeline right-of-ways. Therefore, PAR 1149 is not expected to convert any classification of farmland to non-agricultural use or conflict with zoning for agricultural use or a Williamson Act contract.

Based upon these considerations, significant agricultural resource impacts are not anticipated and will not be further analyzed this ~~Draft~~ Final EA. Since no significant agriculture resources impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	**Less Than Significant Impact**	**No Impact**
III. AIR QUALITY. Would the project:			
a) Conflict with or obstruct implementation of the applicable air quality plan?	☐	☐	☑
b) Violate any air quality standard or contribute to an existing or projected air quality violation?	☐	☑	☐
c) Result in a cumulatively considerable net increase of any criteria pollutant for which the project region is non-attainment under an applicable federal or state ambient air quality standard (including releasing emissions that exceed quantitative thresholds for ozone precursors)?	☐	☑	☐

		Potentially Significant Impact	Less Than Significant Impact	No Impact
d)	Expose sensitive receptors to substantial pollutant concentrations?	☐	☑	☐
e)	Create objectionable odors affecting a substantial number of people?	☐	☑	☐
f)	Diminish an existing air quality rule or future compliance requirement resulting in a significant increase in air pollutant(s)?	☐	☐	☑

III. a) and f) Attainment of the state and federal ambient air quality standards protects sensitive receptors and the public in general from the adverse effects of criteria pollutants which are known to have adverse human health effects. PAR 1149 contributes directly to carrying out the goals of the 2007 AQMP by implementing control measure FUG-04. Consistent with control measure FUG-04, PAR 1149 is expected to reduce VOC emissions from all affected source categories, which in turn, will contribute to attaining the state and federal ambient air quality standards. Thus, because PAR 1149 implements control measure FUG-04 from the 2007 AQMP, it is not expected to conflict or obstruct implementation of the applicable AQMP.

Implementing PAR 1149 would not diminish an existing air quality rule or future compliance requirement, nor conflict with or obstruct implementation of the applicable air quality plan. It would implement in part the 2007 AQMP control measure FUG-04.

III. b), c) & d) For a discussion of these items, refer to the following analysis.

Air Quality Significance Criteria

To determine whether or not air quality impacts from adopting and implementing the proposed amendments are significant, impacts will be evaluated and compared to the following criteria. The project will be considered to have significant adverse air quality impacts if any one of the thresholds in Table 2-1 are equaled or exceeded.

Construction Air Quality Impacts

~~PAR 1149 would not require any construction; therefore, there would be no adverse construction impacts.~~ Subsequent to the release of the Draft EA, one owner/operator stated that construction would be required on drain dry tanks to comply with PAR 1149. In order to comply with PAR 1149, this owner operator would need to cut the roof support legs to one-foot high on their drain dry tanks.

Table 2-1
Air Quality Significance Thresholds

Mass Daily Thresholds		
Pollutant	**Construction**	**Operation**
NOx	100 lbs/day	55 lbs/day
VOC	75 lbs/day	55 lbs/day
PM10	150 lbs/day	150 lbs/day
SOx	150 lbs/day	150 lbs/day
CO	550 lbs/day	550 lbs/day
Lead	3 lbs/day	3 lbs/day
Toxic Air Contaminants (TACs) and Odor Thresholds		
TACs (including carcinogens and non-carcinogens)	Maximum Incremental Cancer Risk ≥ 10 in 1 million Hazard Index ≥ 1.0 (project increment) Hazard Index ≥ 3.0 (facility-wide)	
Odor	Project creates an odor nuisance pursuant to SCAQMD Rule 402	
Ambient Air Quality for Criteria Pollutants [a]		
NO2 1-hour average annual average	SCAQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards: 0.25 ppm (state) 0.053 ppm (federal)	
PM10 24-hour average annual geometric average annual arithmetic mean	10.4 µg/m^{3} (recommended for construction) [b] & 2.5 µg/m^{3} (operation) 1.0 µg/m^{3} 20 µg/m^{3}	
Sulfate 24-hour average	1 ug/m^{3}	
CO 1-hour average 8-hour average	SCAQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards: 20 ppm (state) 9.0 ppm (state/federal)	

[a] Ambient air quality thresholds for criteria pollutants based on SCAQMD Rule 1303, Table A-2 unless otherwise stated.

[b] Ambient air quality threshold based on SCAQMD Rule 403.

KEY: lbs/day = pounds per day ppm = parts per million ug/m^{3} = microgram per cubic meter ≥ greater than or equal to

Construction would occur over six to ten weeks. The storage tanks would be drained and degassed. While empty the storage tanks would undergo a routine 10 year API inspection that is already required by other regulatory agencies. The drainage, degassing and inspection would take approximately one week. The storage tank would then be water blasted and coatings would be removed where the legs would be cut. A bobcat loader would be used to support the storage tank roof, while cutting and welding operations occur. Cutting and welding are expected to last three to four days. Only the removal of coatings around where the legs would be cut, and the cutting and welding are attributed to PAR 1149. The remaining operations are considered apart of the 10 year API inspection of the storage tank.

To reduce the economic impact and any bottlenecks in production only one storage tank would be modified at a time. There are 32 drain dry tanks, but only 14 would need to be modified. Construction criteria emissions are presented in Table 2-2. Detailed calculations can be found in Appendix B.

Table 2-2
Peak Day Criteria Emissions from PAR 1149 - Construction Only

Description	**CO, lb/day**	**NOx, lb/day**	**VOC, lb/day**	**SOx, lb/day**	**PM10, lb/day**	**PM2.5, lb/day**
Construction	4.0	11	0.59	1.1	0.59	0.56

Operational Air Quality Impacts
PAR 1149 would generate emissions from the combustion of VOCs in thermal oxidizers or internal combustion engines during the degassing process and diesel-fueled heavy duty trucks used to deliver the thermal oxidizers or internal combustion engines.

VOC Emission Reductions

The proposed rule amendment would set a vapor concentration limit of 5,000 ppmv on tanks and pipelines subject to the rule. Connections, hoses, and vacuum trucks would also be required to keep emissions below 5,000 ppmv. Thermal oxidizers and internal combustion engines with afterburners are considered control technology for tanks. Carbon adsorption is expected to be used for pipelines. Alternative methods such as routing the exhaust to other tanks, applying chemicals or water to reduce vapors or any other means to reduce the tank or pipeline concentration would be allowed so long as hydrocarbon vapors with a concentration greater than 5,000 ppmv were not allowed to be vented to atmosphere. Control devices used to reduce the vapors in tanks and pipelines would be limited to an exhaust concentration of 500 ppmv, which is consistent with other SCAQMD rules.

A limit of 5,000 ppmv captures an estimated 90 percent or more of the remaining emissions. Utilizing the degassing logs, a comparison can be made between the quantity of emission captured when the 5,000 ppmv standard is reached and the total quantity of emissions in the storage tank. Reviewing the example in Table 1-3, almost 97 percent of emissions are captured when degassing to 5,000 ppmv (roughly ten percent LEL). Reviewing all of the storage tanks that met or exceeded the standard, a limit of 5,000 ppmv captures between 86.3 percent and 99.7 percent of emissions from tanks. The average emission reduction is 95.8 percent.

Adoption of a vapor concentration standard of 5,000 ppmv will reduce emissions from existing and newly applicable sources by at least 90 percent. The total annual uncontrolled VOC emissions from existing and newly applicable sources are 1.99~~7~~ tons per day. The current provisions in the rule already reduce 0.57 tons per day of the uncontrolled VOC emissions. The proposed rule amendments will reduce VOC emissions by another 1.27~~5~~ tons per day calculated based on the practice of degassing to 5,000 ppmv (see Table 2-3~~2~~). Further controlling vacuum trucks used to remove residual product and sludge, requiring residual product and sludge to held in closed containers that are free of liquid and vapor leaks and establishing a vapor concentration requirement for control devices will limit fugitive emission losses.

Table 2-3~~2~~
Emission Reductions from All Rule 1149 Sources

Source	**Emission Inventory, (ton/day)**	**Emissions Controlled by Existing Rule 1149, (ton/day)**	**Remaining Emissions Inventory, (ton/day)**	**Emissions Controlled by Proposed Amended Rule, (ton/day)**
ASTs currently subject to rule	1.42	0.5	0.92	0.82
USTs	0.07	0.07	0	0
Newly applicable ASTs	0.1	0	0.1	0.09
Pipelines	0.4	0	0.4	0.36
Total emissions from all Rule 1149 sources	**1.99~~7~~**	**0.57**	**1.42**	**1.27~~5~~**

Along with reductions in VOC emissions from the proposed provisions of this rule, there would also be some increases in criteria pollutants because of increased use of control equipment. Except in the limited circumstances where liquid balancing is used, the primary methods of VOC control for storage tanks is oxidation using internal combustion engines and thermal oxidizers. Conservatively, it is assumed that all new storage tank sources would be controlled using either an internal combustion engine or thermal oxidizer. Undoubtedly, some sources will use liquid balancing and other technologies or degassing methods may be developed which do not require combustion.

Currently, VOCs from pipelines are typically not controlled. Almost all pipelines are expected to control VOC emission using carbon adsorption to comply with PAR 1149. There is one vendor that currently uses ICEs or thermal oxidizers when near receptors and vents to the atmosphere when receptors are distant. This vendor would use ICEs or thermal oxidizers for all pipeline segments whether near or far from receptors.

Over the past three years, 47.9 million cubic feet of tank space was degassed on average annually. Additionally, another 3.7 million cubic feet of degassing would be necessary with the proposed pipeline and smaller/low vapor pressure tank requirements. The total average amount of degassing would increase to 51.6 million cubic feet annually.

SCAQMD default emission factors were used for criteria pollutants emitted by thermal oxidizers and internal combustion engines except for NOx, CO and VOC from internal combustion engines. NOx, CO and VOC emission factors for internal combustion engines were taken from a source test conducted on an internal combustion engine fired with propane controlling vapors from a tank degassing operation. Like other internal combustion engines used for this purpose, it is equipped with a catalytic converter. The ratio of thermal oxidizer use (69 percent) to internal combustion engine use (31 percent) was determined from notification data.

Peak Day Activities

Affected facility owners/operators contact SCAQMD staff before degassing under the current rule. Based on the information collected from affected facility owners/operators, the highest Rule 1149 activity in the last four years occurred on April 13, 2006. On that day, two large gasoline tanks (4,380,000 and 3,360,000 gallon capacity), two large crude tanks (19,446,000 and 18,900,000 gallon capacity, and one small crude tank (1,596,000 gallon capacity) were degassed on the same day. Degassing occurred for approximately 24 hours during that peak day (47 hours total). SCAQMD estimates an additional 84 hours would be required to degas the same existing storage tanks according to PAR 1149 requirements, and seven hours would be required to degas an additional storage tank. Therefore, PAR 1149 would require an additional 91 hours for storage tanks on a peak day. Storage tanks are expected to be either degassed by ICEs or thermal oxidizers. Two new pipelines are expected to be degassed. The pipelines are expected to be degassed using carbon adsorption, so no indirect emissions would occur from the pipeline degassing process itself. The peak day projection is summarized in Table 2-4~~3~~.

Table 2-4~~3~~
Projected Peak Day Storage Tank Degassing Activity

Source	**Capacity**	**Content**	**Hours to Degas under existing Rule 1149**	**Hours to Degas under PAR 1149**	**Increased Hours to Degas under PAR 1149**
Existing	4,380,000	Gasoline	6.7	18.8	12.1
Existing	3,360,000	Gasoline	5.2	14.6	9.4
Existing	19,446,000	Crude	16.9	47.3	30.4
Existing	1,596,000	Crude	1.4	3.9	2.5
Existing	18,900,000	Crude	16.4	45.9	29.5
New AST	3,206,000	Xylene	N/A	7	7
New Pipeline	155,016	gasoline	N/A	6.2	6.2
New Pipeline	155,016	crude	N/A	3.4	3.4
Total hourly increase:					**100.4**

SCAQMD staff assumed that an extra heavy duty truck trip would be needed to meet PAR 1149 requirements for existing tanks. The additional heavy-duty truck trip would be used to deliver carbon adsorption units for sludge removal from tanks that hold heavy crude products. Storage tanks that are now exempted from Rule 1149, but would need to control VOCs during degassing pursuant to operating under PAR 1149, would require two heavy-duty truck trips to deliver carbon and thermal oxidizers or ICEs. Pipelines are expected to need one heavy-duty truck trips to deliver carbon adsorption units or thermal oxidizers or ICEs. Based on these assumptions, an additional seven heavy-duty truck trips would be required to degas storage tanks and pipeline on a worst-case day under PAR 1149. ~~Staffed assumed that there would need to be two truck trips associated with the degassing processes. Based on the peak day assumptions above, an additional six diesel truck trips would be required to degas the additional tank and two pipelines.~~

The emissions from control technology and diesel truck trips are presented in Table 2-5~~4~~. Total criteria emissions from construction and operations related to PAR 1149 are presented in Table 2-6. Detailed calculations are included in Appendix B. Since construction and operational emissions are expected to overlap, the criteria emissions from both construction and operations are compared to the operational significance thresholds. The operational significant thresholds are equivalent or lower than the construction thresholds. None of the criteria emissions from PAR 1149 exceed the SCAQMD significance criteria presented in Table 2-1. Therefore, PAR 1149 is not expected to be significant for criteria emissions.

Table 2-5
Peak Day Criteria Emissions from PAR 1149 - Operation Only

Description	**CO, lb/day**	**NOx, lb/day**	**VOC, lb/day**	**SOx, lb/day**	**PM10, lb/day**	**PM2.5, lb/day**
Control Technology	9	17	0.65	2.9	1.5	1.5
Mobile Source	2.6	17	0.59	0.022	0.31	0.28
Total	11	34	1.2	2.9	1.8	1.8

Table 2-6~~4~~
Total Peak Day Criteria Emissions from PAR 1149

Description	**CO, lb/day**	**NOx, lb/day**	**VOC, lb/day**	**SOx, lb/day**	**PM10, lb/day**	**PM2.5, lb/day**
Construction	4.0	11	0.59	1.1	0.59	0.56
Operational	12	37	1.3	2.9	1.9	1.9
Total	16	48	1.9	4.1	2.5	2.4
Operational Significance Thresholds	550	55	55	150	150	55
Significant?	No	No	No	No	No	No

Since construction and operational emissions overlap, the combined peak day construction and peak day operational emissions were added together and compared to the operational significance thresholds. The operational significance thresholds are equivalent or lower than the construction significant thresholds.

~~**Description**~~	~~**CO, lb/day**~~	~~**NOx, lb/day**~~	~~**VOC, lb/day**~~	~~**SOx, lb/day**~~	~~**PM10, lb/day**~~	~~**PM2.5, lb/day**~~
~~Control Technology~~	~~9~~	~~17~~	~~0.65~~	~~2.9~~	~~1.5~~	~~1.5~~
~~Mobile Source~~	~~2.6~~	~~17~~	~~0.59~~	~~0.022~~	~~0.31~~	~~0.28~~
~~Total~~	~~11~~	~~34~~	~~1.2~~	~~2.9~~	~~1.8~~	~~1.8~~
~~Significance Threshold~~	~~550~~	~~55~~	~~55~~	~~150~~	~~150~~	~~55~~
~~Significant?~~	~~No~~	~~No~~	~~No~~	~~No~~	~~No~~	~~No~~

Air Toxics

Air toxic emissions from combustion of propane were analyzed. Only combustion of propane was examined because based on discussions with vendors it is the fuel burned in the ICEs or thermal oxidizers used for degassing. There would be an increase of toxic emissions from the vapors in the newly captured storage tanks, but since the constituents and concentration of the vapors in the tanks is unknown, these emissions were considered speculative and not included in the analysis.

One pipeline operator uses combustion to control VOC emissions near receptors. For pipeline segments that are several miles away from receptors the operator vents the vapors to the atmosphere. The pipeline operator stated that they would use combustion to control VOC emissions for all pipeline segments to comply with PAR 1149 (i.e., even the segments that are several miles away from receptors). There would be no increase in adverse air toxic impacts to receptors that are near pipeline segments since they are already controlled by combustion (i.e., no change in operation yields no change in emissions). There would be no increase in air toxic impacts to receptors that are several miles away from pipelines since the adverse air toxic impacts would be small for receptors that are over a mile away from the ICEs or thermal oxidizers.

The remaining pipeline operators contacted would use carbon adsorption to reduce VOC emissions under PAR 1149. Carbon adsorption reduces VOC emissions from pipelines, and therefore air toxic emissions during degassing. Therefore, there would be a reduction in toxic emissions from pipeline operators that use carbon adsorption.

Carcinogenic and chronic health risks are estimated for long term processes, so these health risks were not estimated. Since degassing is an infrequent event lasting at the most approximately 48 hours only acute health risks were estimated. Acute health risks were estimated from both ICEs and thermal oxidizers from newly captured storage tanks under PAR 1149. It was assumed that either two additional ICEs or two additional afterburners would be used at a single facility. Using the most conservative assumptions in a Tier II acute health risk assessment (i.e., 25 meter receptor distance, shortest stack height), the hazard index for both ICEs (0.7) and afterburners (0.001) were less than the significant threshold of 1.0. Therefore, PAR 1149 is not expected to be significant for health risk.

Greenhouse Gases

In addition to criteria pollutant emissions, combustion processes generate greenhouse gas (GHG) emissions that have the potential to affect global climate. The following GHG analysis focuses on CO2 emissions because this is the primary GHG pollutant emitted during the combustion process and is the GHG pollutant for which emission factors are most readily available. U.S. Department of Energy, Energy Information Administration factors were used to determine carbon dioxide (CO2) emission factors.

The analysis of GHGs is a much different analysis than the analysis of criteria pollutants for the following reasons. For criteria pollutants, significance thresholds are based on daily emissions because attainment or non-attainment is based on daily exceedances of applicable ambient air quality standards. Further, several ambient air quality standards are based on relatively short-term exposure effects on human health, e.g., one-hour and eight-hour. Since the half-life of CO2 is approximately 100 years, the effects of GHGs are longer-term, affecting global climate over a relatively long time frame. Further, the action of GHGs is global in nature, rather than local or even regional. As a result, GHG emission impacts are considered to be cumulative impacts rather than project-specific impacts.

Typical GHG emission inventories (EPA[4], ARB[5], etc.) present directly emitted GHGs during a given year. Table 2-7~~5~~ presents CO2 emissions from PAR 1149.

Table 2-7~~5~~
CO2 Emissions from PAR 1149

Description	**CO2, ton/yr**	**CO2, metric ton/yr**
Construction	7.0	6.4
Operation	1,425	1,293
Total	1,432	1,299

~~**Description**~~	~~**CO2, ton/yr**~~	~~**CO2, metric ton/yr**~~
~~Control Technology~~[a]	~~1,217~~	~~1,198~~
~~Mobile Source~~[b]	~~70~~	~~69~~
~~Total~~	~~1,287~~	~~1,267~~

~~a) Control Technology Annual CO2 from Table 7 – Related Increase in Criteria Pollutants and Greenhouse Gas Emissions in the Draft Staff Report for Proposed Amended Rule 1149 – Storage Tank and Pipeline Cleaning and Degassing, February 2008.~~
~~b) Estimated using EMFAC2007 emission factors,~~

In the absence of a specific significance threshold, SCAQMD staff has evaluated significance for projects where it is the lead agency on a case-by-case basis. In this analysis, SCAQMD staff has used a variety of benchmarks to evaluate GHG impacts. As additional information is compiled with regard to the level of GHG emissions that constitute a significant cumulative climate change impact, SCAQMD will continue to revisit and possibly revise the level of GHG emissions considered to be significant.

In its *CEQA & Climate Change* document (January, 2008), CAPCOA identifies many potential GHG significance threshold options. The CAPCOA document indicates that establishing quantitative thresholds is a balance between setting the level low enough to capture a substantial portion of future residential and non-residential development, while also setting a threshold high enough to exclude small development projects that will contribute a relatively small fraction of the cumulative statewide GHG emissions. For example, CAPCOA identifies one potential significance threshold as 10,000 metric tons per year, which was considered by the Market Advisory Committee for inclusion in a Greenhouse Gas Cap and Trade System in California. Another potential threshold identified by CAPCOA is 25,000 metric tons per year, which is CARB’s proposed mandatory reporting threshold under AB 32. GHG emissions in the year 2014 from PAR 1149 would be lower than both of these reporting thresholds.

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[4] EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005, http://www.epa.gov/climatechange/emissions/downloads06/07CR.pdf, April 15, 2007

[5] ARB, Statewide Greenhouse Gas (GHG) Emissions Inventory 1990 to 2004, http://www.arb.ca.gov/cc/ccei/emsinv/emsinv.htm.

Finally, another approach to determining significance is to estimate what percentage of the total inventory of GHG emissions are represented by emissions from a single project. If emissions are a relatively small percentage of the total inventory, it is possible that the project will have little or no effect on global climate change. According to available information, the statewide inventory of CO2eq. emission is as follows: 1990 GHG emissions equal 427 million metric tons of CO2eq. and 2020 GHG emissions equal 600 million metric tons of CO2eq. with business as usual. Interpolating an inventory for the year 2008 results in 531 million metric tons of CO2eq. CO2 emissions in 2008 of ~~1,267~~ 1,299 metric tons from PAR 1149 represent ~~0.00029~~ 0.00030percent of the statewide GHG inventory in 2008 (Table 2-8~~6~~). This small percentage of GHG emissions compared to the total projected statewide GHG emissions inventory is another basis for the SCAQMD's conclusion that GHG emissions from implementing PAR 1149 are less than significant.

Table 2-8~~6~~
Comparison of Proposed Amended Rule 1149 CO2 Emissions to the 2008 Statewide CO2 Emissions

2008 PAR 1149 Direct CO2 Emissions (metric ton/yr)	2014 Statewide CO2 Emissions (million metric ton/yr)	Percentage of PAR 1149 to Statewide CO2 emissions
~~1,267~~ 1,299	427	~~0.00029~~ 0.00030

PAR 1149 is part of a comprehensive ongoing regulatory program that includes implementing related SCAQMD 2007 AQMP control measures as amended or new rules to attain and maintain with a margin of safety all state and national ambient air quality standards for all areas within its jurisdiction. The 2007 AQMP estimates a CO2 reduction of 427,849 metric tons per year by 2014, and a CO2 reduction of 1,523,445 metric ton per year by 2020. Therefore, PAR 1149 in connection with other 2007 AQMP control measures is not considered to be cumulatively significant.

Since GHG emissions are considered cumulative impacts, and PAR 1149 GHG emissions are below the 10,000 metric ton per year Market Advisory Committee threshold, 25,000 metric ton per year CARB proposed mandatory reporting threshold under AB 32, a small percentage of the total statewide GHG inventory in 2014, and, with other control measures in the 2007 AQMP, which is a comprehensive ongoing regulatory program that would reduce overall CO2 emissions; cumulative GHG adverse impacts from PAR 1149 are not considered significant.

In addition, PAR 1149 establishes a ~~greenhouse gas (~~GHG~~)~~ emission reduction quantification protocol, where GHG emissions may be voluntarily reduced by controlling methane emissions from natural gas pipelines through the GHG quantification protocol calculation methodology. However, since the GHG quantification program is voluntary, no emission reductions were estimated from the GHG quantification protocol program for CEQA purposes.

III. e) Historically, the SCAQMD has enforced odor nuisance complaints through SCAQMD Rule 402 - Nuisance. Affected facilities are not expected to create objectionable odors affecting a substantial number of people for the following reasons: 1) PAR 1149 would occur at existing commercial and industrial facilities that store or transport organic liquids, which are likely to generate odors; 2) PAR 1149 would reduce the amount of VOCs during off-gassing; 3) Degassing operations would occur over short time spans from hours to two days. Therefore, PAR 1149 is not expected to generate odor nuisance.

Conclusion

The proposed project is expected to reduce VOCs and air toxics. Based on the preceding discussion, significant adverse air quality impacts are not expected from PAR 1149, and will not be further analyzed in this ~~Draft~~ Final EA. Since no significant adverse air quality impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	**Less Than Significant Impact**	**No Impact**
IV. BIOLOGICAL RESOURCES. Would the project:			
a) Have a substantial adverse effect, either directly or through habitat modifications, on any species identified as a candidate, sensitive, or special status species in local or regional plans, policies, or regulations, or by the California Department of Fish and Game or U.S. Fish and Wildlife Service?	☐	☐	☑
b) Have a substantial adverse effect on any riparian habitat or other sensitive natural community identified in local or regional plans, policies, or regulations, or by the California Department of Fish and Game or U.S. Fish and Wildlife Service?	☐	☐	☑
c) Have a substantial adverse effect on federally protected wetlands as defined by §404 of the Clean Water Act (including, but not limited to, marsh, vernal pool, coastal, etc.) through direct removal, filling, hydrological interruption, or other means?	☐	☐	☑
d) Interfere substantially with the movement of any native resident or migratory fish or wildlife species or with established native resident or migratory wildlife corridors, or impede the use of native wildlife nursery sites?	☐	☐	☑

		Potentially Significant Impact	Less Than Significant Impact	No Impact
e)	Conflicting with any local policies or ordinances protecting biological resources, such as a tree preservation policy or ordinance?	☐	☐	☑
f)	Conflict with the provisions of an adopted Habitat Conservation plan, Natural Community Conservation Plan, or other approved local, regional, or state habitat conservation plan?	☐	☐	☑

Significance Criteria

Impacts on biological resources will be considered significant if any of the following criteria apply:

- The project results in a loss of plant communities or animal habitat considered to be rare, threatened or endangered by federal, state or local agencies.
- The project interferes substantially with the movement of any resident or migratory wildlife species.
- The project adversely affects aquatic communities through construction or operation of the project.

Discussion

IV. a), b), c), & d) PAR 1149 would further reduce VOC emissions at affected facilities during the cleaning and degassing of storage tanks and pipelines. PAR 1149 would not require or induce new residential or commercial developments. All construction operations are expected to occur within 14 existing dry breakout tanks located at existing industrial facilities. Construction would be limited to reducing the height of the roof support legs to one foot, which would not affect biological resources. Operations would consist of controlling VOC emissions from degassing and cleaning operations using carbon adsorption and/or thermal oxidizers or ICEs applied to existing affected tanks located at existing industrial facilities, which would not affect biological resources. All activities associated with PAR 1149 are expected to occur within the boundaries of existing industrial facilities or along existing pipeline right-of-ways. These properties have already been disturbed and are often cleared of vegetation for fire safety reasons, but not as a result of PAR 1149. Therefore, PAR 1149 would not directly or indirectly affect riparian habitat, federally protected wetlands, or migratory corridors. For the same reasons PAR 1149 is not expected to adversely affect special status plants, animals, or natural communities.

IV. e) & f) PAR 1149 would not conflict with local policies or ordinances protecting biological resources nor local, regional, or state conservation plans because it will only affect cleaning and degassing operations at existing industrial facilities. Additionally, PAR 1149 would not conflict with any adopted Habitat Conservation Plan, Natural Community Conservation Plan, or any other relevant habitat conservation plan for the same reason.

The SCAQMD, as the Lead Agency for the proposed project, has found that, when considering the record as a whole, there is no evidence that the proposed project will have potential for any new adverse effects on wildlife resources or the habitat upon which wildlife depends. Accordingly, based upon the preceding information, the SCAQMD has, on the basis of substantial evidence, rebutted the presumption of adverse effect contained in §753.5 (d), Title 14 of the California Code of Regulations.

Based upon these considerations, significant adverse biological resources impacts are not anticipated and will not be further analyzed in this ~~Draft~~ Final EA. Since no significant adverse biological resources impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	**Less Than Significant Impact**	**No Impact**
V. CULTURAL RESOURCES. Would the project:			
a) Cause a substantial adverse change in the significance of a historical resource as defined in §15064.5?	☐	☐	☑
b) Cause a substantial adverse change in the significance of an archaeological resource as defined in §15064.5?	☐	☐	☑
c) Directly or indirectly destroy a unique paleontological resource or site or unique geologic feature?	☐	☐	☑
d) Disturb any human remains, including those interred outside a formal cemeteries?	☐	☐	☑

Significance Criteria

Impacts to cultural resources will be considered significant if:
- The project results in the disturbance of a significant prehistoric or historic archaeological site or a property of historic or cultural significance to a community or ethnic or social group.
- Unique paleontological resources are present that could be disturbed by construction of the proposed project.
- The project would disturb human remains.

V. a) PAR 1149 would further reduce VOC emissions at affected facilities during the cleaning and degassing of storage tanks and pipelines. PAR 1149 would not require or induce new residential or commercial developments. All activities associated with PAR 1149 are expected to occur within the boundaries of existing industrial facilities or along existing pipeline right-of-ways. <u>All construction operations are expected to occur within 14 existing dry breakout tanks. Construction would be limited to reducing the height of the roof support legs to one foot, which would not affect cultural resources. Operations would consist of controlling VOC emissions from degassing and cleaning operations using carbon adsorption and/or thermal oxidizers or ICEs, which would not affect cultural resources.</u> These properties have already been disturbed, but not as a result of PAR 1149. Therefore, PAR 1149 is not expected to affect property that could be considered historically significant as defined in CEQA Guidelines §15064.5. By reducing VOC and therefore ozone, PAR 1149 would reduce the amount of damage caused by ground level ozone.

V, b), c), & d) PAR 1149 would not cause any new development. PAR 1149 activities are not expected to disturb existing structures or require any earth work. Therefore, no impacts to historical resources are anticipated to occur as a result of implementing the proposed project. PAR 1149 is not expected to require physical changes to the environment, which may disturb paleontological or archaeological resources.

Based upon these considerations, significant adverse cultural resources impacts are not expected from the implementing PAR 1149 and will not be further assessed in this ~~Draft~~ <u>Final</u> EA. Since no significant cultural resources impacts were identified, no mitigation measures are necessary or required.

		Potentially Significant Impact	**Less Than Significant Impact**	**No Impact**
VI.	**ENERGY.** Would the project:			
a)	Conflict with adopted energy conservation plans?	☐	☐	☑
b)	Result in the need for new or substantially altered power or natural gas utility systems?	☐	☐	☑
c)	Create any significant effects on local or regional energy supplies and on requirements for additional energy?	☐	☑	☐
d)	Create any significant effects on peak and base period demands for electricity and other forms of energy?	☐	☑	☐
e)	Comply with existing energy standards?	☐	☐	☑

Significance Criteria

Impacts to energy and mineral resources will be considered significant if any of the following criteria are met:

- The project conflicts with adopted energy conservation plans or standards.
- The project results in substantial depletion of existing energy resource supplies.
- An increase in demand for utilities impacts the current capacities of the electric and natural gas utilities.
- The project uses non-renewable resources in a wasteful and/or inefficient manner.

Discussion

PAR 1149 would further reduce VOC emissions at affected facilities during the cleaning and degassing of storage tanks and pipelines.

VI. a) & e) PAR 1149 does not require any action which would result in any conflict with an adopted energy conservation plan or violation of any energy conservation standard. PAR 1149 is not expected to conflict with adopted energy conservation plans because existing facilities would be expected to continue implementing any existing energy conservation plans.

PAR 1149 is not expected to cause new development. Even withstanding this, the siting of new facilities and residences is predominantly governed by the local jurisdiction and not within the purview of the SCAQMD. The local jurisdiction or energy utility sets standards (including energy conservation) and zoning guidelines regarding new development and will approve or deny applications for building new facilities. During the local land use permit process, the project proponent may be required by the local jurisdiction or energy utility to undertake a site-specific CEQA analysis to determine the impacts, if any, associated with the siting and construction of new development.

As a result, PAR 1149 would not conflict with energy conservation plans, use non-renewable resources in a wasteful manner, or result in the need for new or substantially altered power or natural gas systems. Accordingly these impact issues will not be further analyzed in ~~the Draft~~ this Final EA.

VI. b), c) & d) The primary effects of implementing PAR 1149 diesel fuel would be used to transport afterburners, internal combustion engines or carbon to facilities. Staff estimates that one additional tank (3,206,000 gallon capacity) and two pipelines (155,016 gallon capacity) may be degassed in a given day because of PAR 1149. In addition, staff estimates that existing storage tanks would require additional destruction of VOCs to comply with PAR 1149 requirements.

Propane Impacts

The highest Rule 1149 activity in the last four years occurred on April 13, 2006. On that day, two large gasoline tanks (4,380,000 and 3,360,000 gallon capacity), two large crude tanks (19,446,000 and 18,900,000 gallon capacity, and one small crude tank (1,596,000 gallon capacity) were degassed on the same day. Degassing occurred for approximately 47 hours during that peak day. SCAQMD estimates an additional 84 hours would be required to degas the same existing storage tanks according to PAR 1149 requirements, and seven hours would be required to degas additional tank. Therefore, PAR 1149 would require an additional 91 hours on a peak day. Assuming 8.8 gallons of propane per hour would be required, then 800 gallons of propane would be required on a peak day. According to the California Energy Commission 26 million gallons of propane are used in California per year for motor vehicles[6], which is 71,233 gallons per day. Based on the only the propane available for motor vehicles, 880 gallons per day would be less than 10 percent (1.1 percent) of the 71,233 gallons per day of propane available. Therefore, the additional propane use would not be significant.

Based on a survey of pipeline owners/operators, they would not use ICEs or thermal oxidizers. Therefore, there would be no propane used for the degassing of pipelines.

Diesel Impacts

Based on the peak day assumptions above, an additional ~~six~~ seven trucks would be required to assist in degassing currently affected tanks and to degas the additional tank and two pipelines. Assuming a 40-mile, one-way trip and a five mile per gallon of diesel fuel efficiency approximately 112 ~~96~~ gallons of diesel would be consumed on a peak day.

Using fuel economy values from the ARB's Offroad Database approximately 15 gallons of diesel fuel would be used by construction equipment on a peak day. Assuming one 40-mile round trip by a heavy-duty truck, approximately 16 gallons of diesel fuel would also be used. Therefore, 31 gallons of diesel fuel would be used by construction equipment/heavy-duty trucks during a peak construction day.

Based on the preceding estimates, PAR 1149 is expected to generate a peak daily demand for diesel fuel of 143 gallons. According to the 2007 AQMP, 10 million gallons of diesel is consumed every day. Since a total of 143 ~~96~~ gallons of diesel per day is less than one percent (0.0014 percent) of the diesel available, the proposed project is not considered to have a significant adverse impact on diesel fuel use.

Electricity Impacts

PAR 1149 is not expected to require any additional electricity usage.

Based upon the above considerations, the proposed project is not expected to use energy in a wasteful manner, and would not substantially deplete energy resources.

Based upon the preceding analysis, it is not expected that PAR 1149 would create any significant effects on peak and base period demands for electricity and other forms of energy since only insignificant use of propane and diesel fuel are expected.

Therefore, PAR 1149 is not expected to generate significant adverse energy resources impacts and will not be discussed further in this ~~Draft~~ Final EA. Since no significant energy impacts were identified, no mitigation measures are necessary or required.

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[6] CEC, Making The Case For Propane Motor Fuel**,** http://www.energy.ca.gov/2005_energypolicy/documents/ 004-12-20_workshop/2004-12-20_PROPANE_FUEL.PDF.

	Potentially Significant Impact	Less Than Significant Impact	No Impact
VII. GEOLOGY AND SOILS. Would the project:			
a) Expose people or structures to potential substantial adverse effects, including the risk of loss, injury, or death involving:	☐	☐	☑
• Rupture of a known earthquake fault, as delineated on the most recent Alquist-Priolo Earthquake Fault Zoning Map issued by the State Geologist for the area or based on other substantial evidence of a known fault?	☐	☐	☑
• Strong seismic ground shaking?	☐	☐	☑
• Seismic–related ground failure, including liquefaction?	☐	☐	☑
• Landslides?	☐	☐	☑
b) Result in substantial soil erosion or the loss of topsoil?	☐	☐	☑
c) Be located on a geologic unit or soil that is unstable or that would become unstable as a result of the project, and potentially result in on- or offsite landslide, lateral spreading, subsidence, liquefaction or collapse?	☐	☐	☑
d) Be located on expansive soil, as defined in Table 18-1-B of the Uniform Building Code (1994), creating substantial risks to life or property?	☐	☐	☑
e) Have soils incapable of adequately supporting the use of septic tanks or alternative waste water disposal systems where sewers are not available for the disposal of waste water?	☐	☐	☑

Significance Criteria

Impacts on the geological environment will be considered significant if any of the following criteria apply:

- Topographic alterations would result in significant changes, disruptions, displacement, excavation, compaction or over covering of large amounts of soil.

- Unique geological resources (paleontological resources or unique outcrops) are present that could be disturbed by the construction of the proposed project.
- Exposure of people or structures to major geologic hazards such as earthquake surface rupture, ground shaking, liquefaction or landslides.
- Secondary seismic effects could occur which could damage facility structures, e.g., liquefaction.
- Other geological hazards exist which could adversely affect the facility, e.g., landslides, mudslides.

Discussion

VII. a, b, c, d & e) PAR 1149 would further reduce VOC emissions at affected facilities during the cleaning and degassing of storage tanks and pipelines. PAR 1149 would not require or induce development. All activities associated with PAR 1149 are expected to occur within the boundaries of existing industrial facilities or along existing pipeline right-of-ways. All construction operations are expected to occur within 14 existing dry breakout tanks. Construction would be limited to reducing the height of the roof support legs to one foot, which would not affect geological resources. Operations would consist of controlling VOC emissions from degassing and cleaning operations using carbon adsorption and/or thermal oxidizers or ICEs, which would not affect geological resources. ~~These properties~~ Affected facilities have already been disturbed, but not as a result of PAR 1149. Since no ~~construction or~~ earth work is expected, PAR 1149 is not expected to expose people or structures to potential substantial effects from seismic related activity, landslides, soil erosion or the loss of top soil. The proposed project would not be located on a geologic unit or soil that is unstable or would become unstable as a result of the proposed project, be located on expansive soil. The proposed project would not require or modify septic tanks or alternative waste water disposal systems where sewers are not available for disposing of wastewater.

Based on the above discussion, the proposed project is not expected to have an adverse impact on geology or soils. Since no significant adverse impacts are anticipated, this environmental topic will not be further analyzed in this ~~draft~~ Final EA. No mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant Impact	No Impact
VIII. HAZARDS AND HAZARDOUS MATERIALS. Would the project:			
a) Create a significant hazard to the public or the environment through the routine transport, use, disposal of hazardous materials?	☐	☑	☐

		Potentially Significant Impact	Less Than Significant Impact	No Impact
b)	Create a significant hazard to the public or the environment through reasonably foreseeable upset and accident conditions involving the release of hazardous materials into the environment?	☐	☑	☐
c)	Emit hazardous emissions, or handle hazardous or acutely hazardous materials, substances, or waste within one-quarter mile of an existing or proposed school?	☐	☑	☐
d)	Be located on a site which is included on a list of hazardous materials sites compiled pursuant to Government Code §65962.5 and, as a result, would create a significant hazard to the public or the environment?	☐	☐	☑
e)	For a project located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public airport or public use airport, would the project result in a safety hazard for people residing or working in the project area?	☐	☐	☑
f)	For a project within the vicinity of a private airstrip, would the project result in a safety hazard for people residing or working in the project area?	☐	☐	☑
g)	Impair implementation of or physically interfere with an adopted emergency response plan or emergency evacuation plan?	☐	☐	☑
h)	Expose people or structures to a significant risk of loss, injury or death involving wildland fires, including where wildlands are adjacent to urbanized areas or where residences are intermixed with wildlands?	☐	☑	☐
i)	Significantly increased fire hazard in areas with flammable materials?	☐	☑	☐

Significance Criteria

Impacts associated with hazards will be considered significant if any of the following occur:

- Non-compliance with any applicable design code or regulation.
- Non-conformance to National Fire Protection Association standards.
- Non-conformance to regulations or generally accepted industry practices related to operating policy and procedures concerning the design, construction, security, leak detection, spill containment or fire protection.
- Exposure to hazardous chemicals in concentrations equal to or greater than the Emergency Response Planning Guideline (ERPG) 2 levels.

PAR 1149 would further reduce VOC emissions at affected facilities during the cleaning and degassing of storage tanks and pipelines.

VIII. a & b) PAR 1149 would include adverse hazards from the gases and/or vapors in the storage tanks and pipelines and auxiliary fuel for control equipment.

Gases and/or Vapors in Storage Tanks

PAR 1149 may require lengthening the time of degassing operations for larger tanks that currently degassed. The increase degassing time would reduce the amount of vapors/VOCs release from the larger tanks. Reducing the amount of vapors/VOCs is expected to reduce possible explosive or flammability hazards from the larger tanks. Therefore, PAR 1149 is expected to reduce hazards from larger tanks.

PAR 1149 would require the degassing of small storage tanks and extending degassing operations for larger storage tanks.

Based on conversations with degassing vendors, PAR 1149 is expected to expand the number of tanks degassed, but is not expected to add new facilities. Since PAR 1149 would include small tanks and extend degassing of existing tanks, the adverse impact of a fire or explosion would be equal or less than the existing risk. When comparing worst-case adverse impacts smaller tanks would generate smaller fires and explosions than larger tanks. Extending the degassing of existing larger tanks would not change adverse impacts from a fire or explosion, since the worst-case would be the same or less.

In addition, the ignitability or explosivity of a gas or vapor is limited by its concentration in air. The concentration at which a gas or vapor may ignite or explode is bounded by two explosive limits: the upper and lower explosive limits. Above the upper explosive limit, there is not enough oxygen to ignite the gas or vapor. Below the lower explosive limit, the gas or vapor concentration is too low to burn or explode.

Currently, the vapors/gases from smaller tanks are vented to the atmosphere, and higher vapor/gas concentrations are allowed to escape from larger tanks than would be allowed by PAR 1149. The amount of time vapors/gasses are within the explosive limit concentrations may be shorter, since it is expected that the vapors/gasses would dissipate quicker in the open atmosphere than during the degassing process, which could occur over two days. However, once the vapors/gasses are exposed to the open atmosphere, they are uncontrolled. So the vapor/gas released from the tanks can travel freely. Therefore, it is possible for a vapor/gas cloud with concentrations within the explosive range to move closer to the fenceline or off-site.

Even though degassing smaller tanks, and extending degassing for larger tanks, may lengthen the time concentrations are within the explosive range, the gases/vapors would be kept localized within the storage tank allowing better control of the explosive or fire hazard. Therefore, PAR 1149 is expected to reduce hazards from smaller tanks.

Auxiliary Fuel for Control Devices Degassing Storage Tanks

PAR 1149 would for storage tanks would typically involve the combustion of VOCs and air toxics using propane-fired thermal oxidizers or ICEs. The accidental release of propane could result in adverse hazard impacts.

Since the probability of accidents is related to the miles traveled the increase number of storage tanks and the addition of pipelines would increase the probability of hazards from an accidental release of propane. However, the national truck accident rate is small (on the order of one accident per ten million miles traveled) and the accident rate with chemical releases is even less, so this would not be a significant risk factor.

In case of a rupture, there is the potential for the gas to pool and boil off. This presents the possibility of a boiling liquid, vapor cloud explosion and fire with potential consequences to nearby structures, storage tanks and off-site receptors.

Propane vapors are heavier than air, so that leaks from the fuel system tend to pool at ground level rather than disperse. The flammability limits of LPG vapor in air are also broader than those for natural gas.

Propane is a non-toxic gas. High propane concentrations reduce oxygen levels that may cause asphyxiation, with early symptoms of dizziness. No harmful long-term effects have been reported from exposure to propane vapors. An odorant added to propane generally enables its detection at concentrations that are below the lower flammability limit and substantially below the concentrations needed for asphyxiation.

Propane is not a cryogen and liquid temperatures of the fuel at tank pressure remain at ambient levels. However, the rapid evaporation of the fuel at atmospheric pressures can, if spilled, cause damage to skin. To avoid direct propane contact to the skin, it is recommended that gloves be used during the refueling process.

Propane has a narrow range of flammability compared to the other transportation fuels. The fuel will only burn within a fuel-to-air ratio between 2.2 percent and 9.6 percent. Propane will rapidly dissipate beyond its flammability range in the open atmosphere. Propane fuel leaks can pose a significant explosion hazard relative to gasoline in enclosed areas. Since propane would be used for combusting VOCs and air toxics from affected storage tanks and pipelines, it is expected that this operation would occur in an open area.

Since the accident release risk of propane is low and propane is likely to dissipate into the atmosphere the adverse hazard risk from PAR 1149 is expected to be less than significant.

In addition, based on conversations with propane vendors, PAR 1149 may increase the number of tanks that would require degassing by adding small tanks; however, these additional tanks are expected to be located at facilities that already degas storage tanks. Since degassing already occurs at these facilities that off-site consequence from these operations is expected to be the same, since these facilities would already have propane use for degassing existing tanks under PAR 1149.

Gases and/or Vapors in Pipelines

From the current and planned activities, it does not appear that the use of internal combustion engines or thermal oxidizers would increase from pipeline repair and maintenance operations. Instead, owner/operators would generally use non-combustion control technology such as carbon adsorption. There was only one company contacted that currently uses ICEs or thermal oxidizers to control VOCs/toxics in areas around receptors. In areas, where there are no receptors, the company vents the vapors from the pipeline into the atmosphere uncontrolled.

The company would use ICEs or thermal oxidizers to control VOCs/toxics in all situations to comply with PAR 1149 (i.e., including areas where there are no receptors). However, since the company already uses ICEs or thermal oxidizers to control VOCs/toxics near receptors, there would be no increased hazards risk under PAR 1149. In areas where receptors are several miles away, the new use of ICEs or thermal oxidizers would not add any new significant adverse hazards impacts because there are no receptors to be adversely impacted.

Since pipeline owners/operators currently vent vapors from pipelines into the atmosphere without control, there is a possibility that the concentrations from the pipelines could dissipate downwind to concentrations within the LEL and UEL. Vapors within concentrations between the LEL and UEL are flammable or explosive. By better control of VOCs under PAR 1149, the possibility of an explosion or fire caused by uncontrolled release of vapors from pipelines would be reduced. Therefore, no new hazard impacts are expected.

Static Charge in Hoses

During the public workshop for PAR 1149, a comment was made on static charges in hoses. Flammable liquid in hoses may create vapors. These vapors will be near saturation which is well over the upper explosive limit and so won’t be flammable within the hose. However, as the vapors exit the hose fresh air will mix and may potentially create a very small zone where there is an explosive atmosphere. However, as stated earlier any new or extended degassing operations are expected to occur at refineries, terminals and hazardous pipeline where these fluids area already passing through hoses. Therefore, while PAR 1149 may increase the frequency of these liquids passing through hoses, it would not increase the severity of adverse impacts (e.g., the adverse impacts are expected to be the same). Since degassing is not expected to occur frequently, the overall explosive and fire adverse impact is not expected to increase.

Based on the above analysis, PAR 1149 is not expected to create any new significant hazard to the public through the routine transport, use or disposal of hazardous material, or through reasonably foreseeable upset and accident conditions involving the release of hazardous material in to the environment.

VIII. c) PAR 1149 would not alter the handling of hazardous or acutely hazardous materials, substances or waste within one-quarter mile of an existing or proposed school. The combustion of VOCs and toxic air contaminates would reduce the amount of hazardous emissions. Therefore, PAR 1149 is not expected to significantly impact schools.

VIII. d) Government Code §65962.5 is related to hazardous material sites at industrial facilities. PAR 1149 would affect commercial and industrial facilities with organic liquid storage tanks or pipelines. Some of these facilities may be on the list of hazardous material sites compiled pursuant to Government Code §65962.5. However, PAR 1149 is expected to reduce VOC and toxic air emission from degassing operations for all affected storage tanks and pipelines. As a result, PAR 1149 is not expected to adversely affect any facilities included on a list of hazardous material sites and, therefore, would not create a significant hazard to the public or environment

VIII. c) e) & f) PAR 1149 is not expected to result in a safety hazard for people residing or working within two miles of an public airport or public use airport, or air strip. PAR 1149 is expected to reduce the amount of VOCs and air toxic emissions from affected storage tanks and pipelines. The reduction of VOC emissions is expected to reduce explosive risk. Therefore, PAR 1149 is not expected to significantly adversely impact public airports or private air strips.

VIII. g) PAR 1149 is not expected to adversely impact emergency response or evacuation plans. However, if complying with PAR 1149 requires changes to the emergency response or evacuation plan, changes would be minor, so emergency response plans could be easily updated. Therefore, PAR 1149 is not expected to significantly impact emergency response or evacuation plans.

VIII. h) and i) PAR 1149 would lower the probability of an explosion since VOCs from storage tanks would be captured and destroyed. However, PAR 1149 may increase the fire hazard, since it would include combustion to destroy the VOCs. Since the contents of storage tanks that have VOCs are assumed to be flammable, combustible or explosive, the areas around such tanks are expected to be devoid of vegetation or flammable materials. Therefore, no significant increase in wildfires or fire hazard is expected from PAR 1149. PAR 1149 is not expected to increase the risk of fire hazard in general and specifically in areas with flammable materials. PAR 1149 would not expose people or structures to significant risk of loss, injury or death involving wildland fires.

In conclusion, potentially significant adverse hazard impacts resulting from adopting and implementing PAR 1149 are not expected and will not be considered further in this ~~Draft~~ Final EA.

		Potentially Significant Impact	Less Than Significant Impact	No Impact
IX.	**HYDROLOGY AND WATER QUALITY.** Would the project:			
a)	Violate any water quality standards or waste discharge requirements?	☐	☐	☑
b)	Substantially deplete groundwater supplies or interfere substantially with groundwater recharge such that there would be a net deficit in aquifer volume or a lowering of the local groundwater table level (e.g. the production rate of pre-existing nearby wells would drop to a level which would not support existing land uses or planned uses for which permits have been granted)?	☐	☐	☑
c)	Substantially alter the existing drainage pattern of the site or area, including through alteration of the course of a stream or river, or substantially increase the rate or amount of surface runoff in a manner that would result in flooding on- or offsite?	☐	☐	☑
d)	Create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff?	☐	☐	☑
e)	Otherwise substantially degrade water quality?	☐	☐	☑
f)	Place housing within a 100-year flood hazard area as mapped on a federal Flood Hazard Boundary or Flood Insurance Rate Map or other flood hazard delineation map?	☐	☐	☑
g)	Place within a 100-year flood hazard area structures which would impede or redirect flood flaws?	☐	☐	☑
h)	Expose people or structures to a significant risk of loss, injury or death involving flooding, including flooding as a result of the failure of a levee or dam?	☐	☐	☑

		Potentially Significant Impact	**Less Than Significant Impact**	**No Impact**
i)	Inundation by seiche, tsunami, or mudflow?	☐	☐	☑
j)	Exceed wastewater treatment requirements of the applicable Regional Water Quality Control Board?	☐	☐	☑
k)	Require or result in the construction of new water or wastewater treatment facilities or expansion of existing facilities, the construction of which could cause significant environmental effects?	☐	☐	☑
l)	Require or result in the construction of new storm water drainage facilities or expansion of existing facilities, the construction of which could cause significant environmental effects?	☐	☐	☑
m)	Have sufficient water supplies available to serve the project from existing entitlements and resources, or are new or expanded entitlements needed?	☐	☐	☑
n)	Require in a determination by the wastewater treatment provider which serves or may serve the project that it has adequate capacity to serve the project's projected demand in addition to the provider's existing commitments?	☐	☐	☑

Significance Criteria

Potential impacts on water resources will be considered significant if any of the following criteria apply:

Water Quality:
- The proposed project does not increase demand for water by more than 5,000,000 gallons per day.
- The project will cause degradation or depletion of ground water resources substantially affecting current or future uses.
- The project will cause the degradation of surface water substantially affecting current or future uses.
- The project will result in a violation of National Pollutant Discharge Elimination System (NPDES) permit requirements.

- The capacities of existing or proposed wastewater treatment facilities and the sanitary sewer system are not sufficient to meet the needs of the project.
- The project results in substantial increases in the area of impervious surfaces, such that interference with groundwater recharge efforts occurs.
- The project results in alterations to the course or flow of floodwaters.

Water Demand:
- The existing water supply does not have the capacity to meet the increased demands of the project, or the project would use a substantial amount of potable water.
- The project increases demand for water by more than five million gallons per day.

Discussion

IX. a), j), k) & m) PAR 1149 would only affect degassing operations. PAR 1149 would not require any new development or require modifications to buildings or other structures to comply with the proposed amended rule. All of the affected activities occur within facility boundaries or along existing pipeline right-of-ways. Cleaning operations itself are not regulated by PAR 11149, only the degassing operations. PAR 1149 does not require the use of water directly, and therefore, wastewater discharge is not expected from degassing operations.

However, water is used for cleaning. Based on conversations with major degassing companies, large gasoline above ground storage tanks use relatively small amounts of water for rinsing, around (1,000 to 4,200) gallons. Crude and heavy product tanks use more water, on the order of 100,000 gallons per tank. Pipelines use nitrogen instead of water and small underground storage tanks use relatively small amounts of water. Since this water is used currently, and PAR 1149 would only require degassing of these new tanks, no new water is required.

Since the water use is part of the existing cleaning operations, PAR 1149 would not cause increased water usage or the construction of additional water resource facilities, the need for new or expanded water entitlements, an alteration of drainage patterns, or substantially deplete groundwater supplies or interfere substantially with groundwater recharge.

These facilities currently treat wastewater from this process either on-site or off-site with water treatment facilities that currently treat wastewater from these facilities. All facility owners/operators are expected to be complying with all federal, state and local water quality standers and wastewater discharge requirements. PAR 1149 is not expected to affect compliance with federal, state and local water quality standers and wastewater discharge requirements.

c), d), e)& l) PAR 1149 would not require any development or construction, therefore, would not create or contribute to runoff water. Storage tank and pipeline operators are typically required to have secondary containment or housekeeping procedures to prevent contaminating stormwater. While PAR 1149 related operations are not expected to adversely impact stormwater, existing secondary containment and housekeeping practices would also reduce the possibility of creating or contributing runoff water that would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff.

As detailed above, the proposed amended rule is not expected to require additional wastewater disposal capacity, violate any water quality standard or wastewater discharge requirements, or otherwise substantially degrade water quality. As result, no changes to storm water runoff, drainage patterns, groundwater characteristics, or flow are expected. Therefore, potential adverse impacts to drainage patterns, etc., are not expected as a result of implementing PAR 1149.

IX. b), & n) PAR 1149 is not expected to substantially deplete groundwater supplies or interfere with groundwater recharge such that there would be a net deficit in aquifer volume or a lowering of the local groundwater table level. PAR 1149 would not increase demand for water from existing entitlements and resources, and will not require new or expanded entitlements because compliant devices do not use water for any reason. Therefore, no water demand impacts are expected as the result of implementing the proposed amendments.

IX. f), g), h) & i) PAR 1149 would not require any development or construction; therefore, PAR 1149 is not expected to generate construction of any new structures in 100-year flood areas as mapped on a federal Flood Hazard Boundary or Flood Insurance Rate Map or other flood delineation map. As a result, PAR 1149 is not expected to expose people or structures to new significant flooding risks. Degassing requirements at existing affected facilities are not expected not affect any existing risks from flood, inundation, etc. Consequently, PAR 1149 would not affect in any way any potential flood hazards, inundation by seiche, tsunami, or mud flow that may already exist relative to existing facilities.

Based upon the above considerations, significant hydrology and water quality impacts are not expected from the implementation of PAR 1149 and will not be further analyzed in this ~~Draft~~ Final EA. Since no significant hydrology and water quality impacts were identified, no mitigation measures are necessary or required.

		Potentially Significant Impact	Less Than Significant Impact	No Impact
X.	**LAND USE AND PLANNING.** Would the project:			
a)	Physically divide an established community?	☐	☐	☑
b)	Conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction over the project (including, but not limited to the general plan, specific plan, local coastal program or zoning ordinance) adopted for the purpose of avoiding or mitigating an environmental effect?	☐	☐	☑
c)	Conflict with any applicable habitat conservation or natural community conservation plan?	☐	☐	☑

Significance Criteria

Land use and planning impacts will be considered significant if the project conflicts with the land use and zoning designations established by local jurisdictions.

Discussion

X. a) PAR 1149 would further reduce VOC emissions at affected facilities during the cleaning and degassing of storage tanks and pipelines. PAR 1149 does not require any new development. Therefore, PAR 1149 does not include any components that would require physically dividing an established community.

X. b) & c) There are no provisions in PAR 1149 that would affect land use plans, policies, or regulations. Land use and other planning considerations are determined by local governments and no land use or planning requirements will be altered by regulating VOC emissions from cleaning and degassing storage tanks and pipelines. Therefore, PAR 1149 would not affect in any way habitat conservation or natural community conservation plans, agricultural resources or operations, and would not create divisions in any existing communities. Therefore, present or planned land uses in the region will not be significantly adversely affected as a result of the proposed amended rule.

Based upon these considerations, significant land use and planning impacts are not expected from the implementation of PAR 1149 and will not be further analyzed in this ~~Draft~~ Final EA. Since no significant land use and planning impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	**Less Than Significant Impact**	**No Impact**
XI. MINERAL RESOURCES. Would the project:			
a) Result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the state?	☐	☐	☑
b) Result in the loss of availability of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan?	☐	☐	☑

Significance Criteria

Project-related impacts on mineral resources will be considered significant if any of the following conditions are met:

- The project would result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the state.
- The proposed project results in the loss of availability of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan.

Discussion

XI.a) & b) PAR 1149 would further reduce VOC emissions at affected facilities during the cleaning and degassing of storage tanks and pipelines. There are no provisions in PAR 1149 that would result in the loss of availability of a known mineral resource of value to the region and the residents of the state, or of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan because compliances is not expected to require mineral resources such as sand, gravel, etc..

Based upon the above considerations, significant mineral resources impacts are not expected from the implementation of PAR 1149 and will not be further analyzed in this ~~Draft~~ Final EA. Since no significant mineral resources impacts were identified, no mitigation measures are necessary or required.

		Potentially Significant Impact	Less Than Significant Impact	No Impact
XII.	**NOISE.** Would the project result in:			
a)	Exposure of persons to or generation of noise levels in excess of standards established in the local general plan or noise ordinance, or applicable standards of other agencies?	☐	☐	☑
b)	Exposure of persons to or generation of excessive groundborne vibration or groundborne noise levels?	☐	☐	☑
c)	A substantial permanent increase in ambient noise levels in the project vicinity above levels existing without the project?	☐	☐	☑
d)	A substantial temporary or periodic increase in ambient noise levels in the project vicinity above levels existing without the project?	☐	☑	☐

		Potentially Significant Impact	Less Than Significant Impact	No Impact
e)	For a project located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public airport or public use airport, would the project expose people residing or working in the project area to excessive noise levels?	☐	☐	☑
f)	For a project within the vicinity of a private airship, would the project expose people residing or working in the project area to excessive noise levels?	☐	☐	☑

Significance Criteria

Impacts on noise will be considered significant if:

- Construction noise levels exceed the local noise ordinances or, if the noise threshold is currently exceeded, project noise sources increase ambient noise levels by more than three decibels (dBA) at the site boundary. Construction noise levels will be considered significant if they exceed federal Occupational Safety and Health Administration (OSHA) noise standards for workers.
- The proposed project operational noise levels exceed any of the local noise ordinances at the site boundary or, if the noise threshold is currently exceeded, project noise sources increase ambient noise levels by more than three dBA at the site boundary.

Discussion

XII. a) Drain dry breakout tanks would require construction to cut roof support legs on 14 tanks to one foot height. Cutting would be done with oxyacetylene torches and the roof is expected to be supported by a bobcat loader; therefore, construction is not expected to generate a significant amount of noise over the background noise generated by other equipment in and around affected storage tank farms. Tank farms are industrial facilities that generate noise from heavy-duty trucks, rail lines, maintenance and other operations.

Degassing operations occur for existing tanks captured by the existing Rule 1149. Existing degassing operations have not been known for excessive noise. Tank degassing operations would include heavy-duty, diesel truck trips, blowers and either a tank to capture gases or a combustion unit to destroy fugitive VOCs. Pipelines would include heavy-duty, diesel truck trips, blowers and either a tank to capture gases or a carbon adsorption unit.

Existing facilities with storage tanks are expected to be in commercial or industrial zones. Affected facilities are expected to have an existing amount of noise associated with filling, loading, and maintenance operations. Degassing operations are not expected to be substantially noisier than existing operations. Thus, the proposed project is not expected to expose persons to the generation of excessive noise levels above current facility/residential levels. It is expected that any facility/residence affected by PAR 1149 would comply with all existing local noise control laws or ordinances.

In commercial environments Occupational Safety and Health Administration (OSHA) and California-OSHA have established noise standards to protect worker health. It is expected that operators at affected facilities/residences will continue complying with applicable noise standards, which would limit noise impacts to workers, patrons and neighbors.

XII. b) Drain dry breakout tanks would require construction to cut roof support legs on 14 tanks to a one-foot height. Cutting would be done with oxyacetylene torches and the roof is expected to be supported by a bobcat loader. Since these types of equipment do not generate substantial vibrations, construction is not expected to generate a significant amount of groundborne vibration.

Degassing operations occur for tanks that are already captured by the existing Rule 1149. SCAQMD staff is not aware of groundborne vibrations from existing operations. PAR 1149 is not anticipated to expose people to or generate excessive groundborne vibration or groundborne noise levels since ~~no construction operations are expected to occur at the existing facilities and compliance~~ changes to operations is not expected to involve equipment that generates substantial groundborne vibrations.

XII. c) Construction operations would be temporary and only affect 14 breakout tanks; therefore, construction would not contribute to a permanent increase in noise levels. A permanent increase in ambient noise levels at the affected facilities above existing levels as a result of implementing the proposed project is unlikely to occur because degassing operations are infrequent, occurring approximately once a day every three years. PAR 1149 related noise would only occur during degassing operations. Since degassing operations are not expected to increase noise above regulatory noise levels and is only expected to last two days every three years, no permanent increase in ambient noise level is expected.

XII. d) Drain dry breakout tanks would require construction to cut roof support legs on 14 tanks to a one-foot height. Cutting would be done with oxyacetylene torches and the roof is expected to be supported by a bobcat loader. Since these types of equipment do not generate substantial volumes of noise, construction is not expected to generate a substantial amount of ambient noise in the project vicinity above levels existing without the proposed project.

PAR 1149 may cause an increase in periodic or temporary ambient noise levels in the vicinity of affected facilities above levels existing prior to its adoption. However, since the noise levels are expected to be consistent with other operations at affected facilities, PAR 1149 is not expected to cause a substantial increase in periodic or temporary ambient noise levels.

XII. e) & f) PAR 1149 may affect storage tanks near or at airports or airfields. Drain dry breakout tanks would require construction to cut roof support legs on 14 tanks to a one-foot height. Cutting would be done completely onsite with oxyacetylene torches and the roof is expected to be supported by a bobcat loader; therefore, construction is not expected to impact people residing or working in the project area near airports or airfields.

~~However, t~~The noise generated by degassing operations is not expected to be greater than the noise generated for other storage tank operations, such as filling, loading or maintenance. Thus, PAR 1149 is not expected to expose people residing or working in the vicinities of public airports to excessive noise levels.

Based upon these considerations, significant noise impacts are not expected from the implementation of PAR 1149 and are not further evaluated in this ~~Draft~~ Final EA. Since no significant noise impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	**Less Than Significant Impact**	**No Impact**
XIII. POPULATION AND HOUSING. Would the project:			
a) Induce substantial growth in an area either directly (for example, by proposing new homes and businesses) or indirectly (e.g. through extension of roads or other infrastructure)?	☐	☐	☑
b) Displace substantial numbers of existing housing, necessitating the construction of replacement housing elsewhere?	☐	☐	☑
c) Displace substantial numbers of people, necessitating the construction of replacement housing elsewhere?	☐	☐	☑

Significance Criteria

Impacts of the proposed project on population and housing will be considered significant if the following criteria are exceeded:

- The demand for temporary or permanent housing exceeds the existing supply.
- The proposed project produces additional population, housing or employment inconsistent with adopted plans either in terms of overall amount or location.

Discussion

XIII. a) PAR 1149 would further reduce VOC emissions at affected facilities during the cleaning and degassing of storage tanks and pipelines. The proposed project is not anticipated to generate any significant effects, either direct or indirect, on the district's population or population distribution as no additional workers are anticipated to be required to comply with the proposed amendments. Human population within the jurisdiction of the SCAQMD is anticipated to grow regardless of implementing PAR 1149. It is expected that any construction activities at affected facilities would use construction workers from the local labor pool in southern California. As such, PAR 1149 will not result in changes in population densities or induce significant growth in population.

XIII. b) & c) Because the proposed project affects storage tank and pipeline cleaning and degassing at existing industrial facilities, PAR 1149 is not expected to result in the creation of any industry that would affect population growth, directly or indirectly, induce the construction of single- or multiple-family units, or require the displacement of people elsewhere.

Based upon these considerations, significant population and housing impacts are not expected from the implementation of PAR 1149 and are not further evaluated in this ~~Draft~~ Final EA. Since no significant population and housing impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant Impact	No Impact
XIV. PUBLIC SERVICES. Would the proposal result in substantial adverse physical impacts associated with the provision of new or physically altered governmental facilities, need for new or physically altered government facilities, the construction of which could cause significant environmental impacts, in order to maintain acceptable service ratios, response times or other performance objectives for any of the following public services:			
a) Fire protection?	☐	☐	☑
b) Police protection?	☐	☐	☑
c) Schools?	☐	☐	☑
d) Parks?	☐	☐	☑
e) Other public facilities?	☐	☐	☑

Significance Criteria

Impacts on public services will be considered significant if the project results in substantial adverse physical impacts associated with the provision of new or physically altered governmental facilities, or the need for new or physically altered government facilities, the construction of which could cause significant environmental impacts, in order to maintain acceptable service ratios, response time or other performance objectives.

Discussion

XIV. a) & b) The control of VOCs from the cleaning and degassing of storage tanks and pipelines is not expected to change or increase the chances for fires or explosions requiring a response from local fire departments. As shown in the Section VIII - Hazards and Hazardous Material section of this ~~Draft~~ Final EA, the use of portable ICEs and thermal oxidizers is not expected to generate significant explosion or fire hazard impacts. PAR 1149 is not expected to have any adverse effects on local police departments for the following reasons. Police would be required to respond to accidental releases of hazardous materials during transport. Since hazards impacts from implementing PAR 1149 were concluded to be less than significant, potential impacts to local police departments are also expected to be less than significant.

XIV.c) & d) As indicated in discussion under item XIII. Population and Housing, implementing PAR 1149 would not induce population growth or dispersion during either construction or operation. Therefore, with no increase in local population anticipated, additional demand for new or expanded schools or parks is not anticipated. As a result, no significant adverse impacts are expected to local schools or parks.

XIV. e) PAR 1149 is not expected to require the increase for government services. The proposal would not result in the need for new or physically altered government facilities in order to maintain acceptable service ratios, response times, or other performance objectives. There will be no increase in population and, as a result of implementing; therefore, no need for physically altered government facilities.

Based upon these considerations, significant public services impacts are not expected from the implementation of PAR 1149 and are not further evaluated in this ~~Draft~~ Final EA. Since no significant public services impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant Impact	No Impact
XV. RECREATION.			
a) Would the project increase the use of existing neighborhood and regional parks or other recreational facilities such that substantial physical deterioration of the facility would occur or be accelerated?	☐	☐	☑
b) Does the project include recreational facilities or require the construction or expansion of recreational facilities that might have an adverse physical effect on the environment?	☐	☐	☑

Significance Criteria

Impacts to recreation will be considered significant if:
- The project results in an increased demand for neighborhood or regional parks or other recreational facilities.
- The project adversely affects existing recreational opportunities.

Discussion

XV.a) & b) As discussed under "Land Use and Planning" above, there are no provisions in the PAR 1149 that would affect land use plans, policies, or regulations. Land use and other planning considerations are determined by local governments and no land use or planning requirements will be altered by the changes proposed in PAR 1149. The proposed project would not increase the demand for or use of existing neighborhood and regional parks or other recreational facilities or require the construction of new or expansion of existing recreational facilities that might have an adverse physical effect on the environment because it will not directly or indirectly increase or redistribute population.

Based upon these considerations, significant recreation impacts are not expected from the implementation of PAR 1149 and are not further evaluated in this ~~Draft~~ Final EA. Since no significant recreation impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant Impact	No Impact
XVI. SOLID/HAZARDOUS WASTE. Would the project:			
a) Be served by a landfill with sufficient permitted capacity to accommodate the project's solid waste disposal needs?	☐	☑	☐
b) Comply with federal, state, and local statutes and regulations related to solid and hazardous waste?	☐	☐	☑

Significance Criteria

The proposed project impacts on solid/hazardous waste will be considered significant if the following occurs:
- The generation and disposal of hazardous and non-hazardous waste exceeds the capacity of designated landfills.

Discussion

XVI. a and b) PAR 1149 would require one owner/operator to shorten the support legs for 14 drain dry breakout tanks. Paint removed from the support legs that are cut would need disposal. However, the amount of paint removed from where the support legs would be cut is expected to be minor. Since the support legs are metal, it is expected that the cut portions of the legs would be recycled. Therefore, construction is expected to generate only minor waste from paint removed from where the support legs are cut, and this waste is expected to be less than significant.

PAR 1149 would only affect VOCs from liquids stored in pipelines or storage tanks. No solid wastes are expected directly from PAR 1149 operational activities. The remaining liquids and sludge in a tank that is removed during cleaning and degassing is not collected and disposed of as a result of PAR 1149, but is a part of the cleaning process. The liquid and sludge would be collected as part of the cleaning and degassing process associated with operations and maintenance of storage tanks and pipelines. Therefore, no hazardous wastes are expected to be generated by PAR 1149 itself.

Based on discussions with owners/operators, PAR 1149 would increase the use of carbon adsorption. Owners/operators of tank farms or vendors that represent them may need to replace carbon more often in existing systems used to degas storage tanks and would be used for smaller storage tanks that would be captured by PAR 1149. This may require either additional carbon beds or new carbon beds for adsorption. Degassing time would increase for some existing storage tanks and new storage tanks would need to be degassed. Pipeline owners/operators have stated that carbon adsorption is likely to be used to control VOCs during degassing operations. This would add new carbon beds for adsorption.

Carbon from adsorption units is recharged by vendors, but after a period of time the carbon can no longer be reactivated and is disposed of in landfills. ~~Based on discussions with vendors, PAR 1149 would require 30,400 pounds (15.2 tons) of activated carbon.~~ In the Draft EA, it was assumed that 15.2 tons of additional activated carbon per year would be needed. However, owner/operators have stated that additional carbon adsorption would be required during the removal of the sludge from crude storage tanks to comply with PAR 1149. Based on conversations with vendors an additional 36,300 pounds (18.2 tons) of activated carbon would be required. Therefore, the total carbon required per year would be approximately 33.4 tons (15.2 + 18.2).

There are 48 Class II/Class III landfills within the SCAQMD's jurisdiction. The total daily permitted disposal capacity of district landfills is approximately 93,979 tons per day[7]. If all ~~15.2~~ 33.4 tons of carbon waste generated each year were disposed of on the same day, the carbon waste would represent ~~0.000167~~ 0.036 percent of the total district permitted disposal capacity. Solid waste that is ~~0.000167~~ 0.036 percent of the total daily permitted landfill disposal capacity for landfills in the district is well within the disposal capacity of district landfills. Therefore, the proposed project is less than significant for hazardous waste and accidental release.

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[7] SCAQMD. 2007. Final Program Environmental Impact Report for the 2007 Air Quality Management Plan. (SCH. No.2006111064).

Existing carbon vendors are expected to currently comply with federal, state and local statues and regulations related to solid and hazardous waste. PAR 1149 is not expected to alter the disposal of activated carbon or any other solid or hazardous waste. Therefore, carbon vendors are expected to comply with federal, state and local statues and regulations related to solid and hazardous waste under PAR 1149.

Based on these considerations, PAR 1149 is not expected to significantly increase the volume of solid or hazardous wastes disposed at existing municipal or hazardous waste disposal facilities or require additional waste disposal capacity. Further, implementing PAR 1149 is not expected to interfere with any affected facility's ability to comply with applicable local, state, or federal waste disposal regulations. Since no solid/hazardous waste impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	**Less Than Significant Impact**	**No Impact**
XVII. TRANSPORTATION/TRAFFIC. Would the project:			
a) Cause an increase in traffic which is substantial in relation to the existing traffic load and capacity of the street system (i.e., result in a substantial increase in either the number of vehicle trips, the volume to capacity ratio on roads, or congestion at intersections)?	☐	☐	☑
b) Exceed, either individually or cumulatively, a level of service standard established by the county congestion management agency for designated roads or highways?	☐	☐	☑
c) Result in a change in air traffic patterns, including either an increase in traffic levels or a change in location that results in substantial safety risks?	☐	☐	☑
d) Substantially increase hazards due to a design feature (e.g. sharp curves or dangerous intersections) or incompatible uses (e.g. farm equipment)?	☐	☐	☑
e) Result in inadequate emergency access or?	☐	☐	☑
f) Result in inadequate parking capacity?	☐	☐	☑

		Potentially Significant Impact	Less Than Significant Impact	No Impact
g)	Conflict with adopted policies, plans, or programs supporting alternative transportation (e.g. bus turnouts, bicycle racks)?	☐	☐	☑

Significance Criteria

Impacts on transportation/traffic will be considered significant if any of the following criteria apply:

- Peak period levels on major arterials are disrupted to a point where level of service (LOS) is reduced to D, E or F for more than one month.
- An intersection's volume to capacity ratio increase by 0.02 (two percent) or more when the LOS is already D, E or F.
- A major roadway is closed to all through traffic, and no alternate route is available.
- There is an increase in traffic that is substantial in relation to the existing traffic load and capacity of the street system.
- The demand for parking facilities is substantially increased.
- Water borne, rail car or air traffic is substantially altered.
- Traffic hazards to motor vehicles, bicyclists or pedestrians are substantially increased.
- The need for more than 350 employees
- An increase in heavy-duty transport truck traffic to and/or from the facility by more than 350 truck round trips per day
- Increase customer traffic by more than 700 visits per day.

Discussion

XVII. a) & b) PAR 1149 would further reduce VOC emissions at affected facilities during the cleaning and degassing of storage tanks and pipelines.

SCAQMD estimates that two diesel-fueled truck round-trips per day would be required for construction operations. One owner/operator would need to cut support legs for 14 drain dry breakout tanks; however, construction would be restricted to one drain dry breakout tank at a time to prevent disruption of operations.

SCAQMD estimates that during operation ~~six~~ seven diesel-fueled vehicle round trips (for existing storage tanks – an additional truck trip for carbon adsorption, for existing crude storage tanks that would be captured by PAR 1149 - ~~a vacuum truck~~, a truck for the portable ICE or thermal oxidizer, and a truck for propane; for pipelines – a ~~vacuum truck~~, a truck for the carbon adsorption unit~~, truck for the carbon~~) per affected facility. Only the trucks carrying the portable ICE or thermal oxidizer, carbon adsorption unit, carbon and propane would be considered part of the project. Vacuum trucks would be required whether or not PAR 1149 is approved. The maximum daily number of tanks that have been degassed in the past is ten. SCAQMD staff expects that as a worst-case one new aboveground storage tank and two 10-mile sections of pipeline might be degassed or cleaned per peak day.

Therefore, ~~six~~ nine additional trucks trips (two from construction and seven from operation) might be added by PAR 1149 on a worst-case day. However, it is not expected that the affected facilities would be adjacent so in any given area only two additional truck trips are expected to be added to any area by PAR 1149. The addition of two diesel truck trips at three additional non-adjacent facilities is not expect to significantly adversely affect circulation patterns on local roadways or the level of service at intersections near affected facilities.

XVII. c) The activities associated with PAR 1149 are not expected to involve equipment (diesel trucks, ICEs and thermal oxidizers) that extends substantially above the height of storage tanks or nearby structures. Therefore, PAR 1149 will not affect in any way air traffic in the region to any appreciable extent.

XVII. d) Since PAR 1149 affects the degassing and cleaning of tanks or pipelines, no offsite modifications to roadways are anticipated for the proposed project that would result in an additional design hazard or incompatible uses.

XVII. e) Since PAR 1149 affects the degassing and cleaning of tanks or pipelines, no changes are expected to emergency access at or in the vicinity of the affected facilities. The proposed project is not expected to adversely impact emergency access because does not add a substantial amount of equipment and emergency access to storage tanks and pipelines are required by other federal, state and local regulations.

XVII. f) Since PAR 1149 affects the degassing and cleaning of tanks or pipelines, no changes are expected to the parking capacity at or in the vicinity of the affected facilities. PAR 1149 is not expected to require additional workers, so additional parking capacity will not be required. Therefore, the project is not expected to adversely impact on- or off-site parking capacity.

XVII. g) Since PAR 1149 affects the degassing and cleaning of tanks or pipelines, the implementation of PAR 1149 would not result in conflicts with alternative transportation, such as bus turnouts, bicycle racks, et cetera.

Based upon these considerations, PAR 1149 is not expected to generate significant adverse transportation/traffic impacts and, therefore, this topic will not be considered further in this ~~Draft~~ Final EA. Since no significant transportation/traffic impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant Impact	No Impact
XVIII. MANDATORY FINDINGS OF SIGNIFICANCE.			
a) Does the project have the potential to degrade the quality of the environment, substantially reduce the habitat of a fish or wildlife species, cause a fish or wildlife population to drop below self-sustaining levels, threaten to eliminate a plant or animal community, reduce the number or restrict the range of a rare or endangered plant or animal or eliminate important examples of the major periods of California history or prehistory?	☐	☐	☑
b) Does the project have impacts that are individually limited, but cumulatively considerable? ("Cumulatively considerable" means that the incremental effects of a project are considerable when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects)	☐	☑	☐
c) Does the project have environmental effects that will cause substantial adverse effects on human beings, either directly or indirectly?	~~☑~~	☑	☐

Discussion

XVIII. a) As discussed in the “Biological Resources” section, PAR 1149 is not expected to significantly adversely affect plant or animal species or the habitat on which they rely because PAR 1149 is expected to affect equipment or processes located at existing residential or commercial facilities, which are typically areas that have already been greatly disturbed and that currently do not support such habitats. PAR 1149 would require construction to cut roof support legs from 14 drain dry breakout tanks to one foot height. The construction would occur within the drain dry breakout tanks at existing industrial facilities so no biological adverse impacts are expected.

Additionally, PAR 1149 does not require or induce construction of any new land use projects that could affect biological resources. Construction of new land use projects would be done for reasons unrelated to PAR 1149.

XVIII. b) Because PAR 1149 does not generate project-specific adverse impacts from ~~other~~ any environmental topic~~s~~ ~~besides air quality~~, cumulative impacts are not consider to be "cumulatively considerable” as defined by CEQA guidelines §15065(a)(3)~~ for any air quality topic besides air quality~~. For example, the environmental topics checked ‘No Impact’ (e.g., aesthetics, agriculture resources, biological resources, cultural resources, geology and soils, hydrology and water quality, land use and planning, mineral resources, population and housing, public services, recreation, and transportation and traffic) would not be expected to make any contribution to potential cumulative impacts whatsoever. For the environmental topic checked 'Less than Significant Impact' (e.g., air quality, energy, hazards and hazardous material, noise and solid/hazardous waste), the analysis indicated that project impacts would not exceed any project-specific significance thresholds. This conclusion is based on the fact that the analyses for each of these environmental areas concluded that the incremental effects of the proposed project would be minor and, therefore, not considered to be cumulatively considerable. Also, in the case of air quality impacts, the net effect of implementing the proposed project with other proposed rules and regulations, and AQMP control measures is an overall reduction in district-wide emissions contributing to the attainment of state and national ambient air quality standards. Therefore, it is concluded that PAR 1149 has no potential for significant cumulative or cumulatively considerable impacts in any environmental areas.

XVIII. c) Based on the foregoing analyses, PAR 1149 ~~may~~ is not expected to cause significant adverse effects on human beings. ~~Significant adverse air quality impacts from the implementation of PAR 1149 will be evaluated in the Draft EA.~~ Based on the preceding analyses, no significant adverse impacts to aesthetics, agriculture resources, air quality, biological resources, cultural resources, energy, geology and soils, hazards and hazardous materials, hydrology and water quality, land use and planning, mineral resources, noise, population and housing, public services, recreation, solid/hazardous waste and transportation and traffic are expected as a result of the implementation of PAR 1149.

As discussed in items I through XVIII above, the proposed project is not expected to cause significant adverse environmental effects.

APPENDIX A

PROPOSED AMENDED RULE 1149

In order to save space and avoid repetition, please refer to the latest version of the PAR 1149 located elsewhere in the final rule package. The PAR 1149 (PAR April 4, 2008) version of the proposed amended rule circulated with the Draft EA released on March 11, 2008 for a 30-day public review and comment period ending April 9, 2008 has been updated but, as noted in the preface, the changes do not require the EA to be recirculated.

Original hard copies of the Draft EA, which include PAR 1149 (PAR April 4, 2008) version of the proposed amended rule circulated with the Draft EA, can be obtained through the SCAQMD Public Information Center at the Diamond Bar headquarters or by calling (909) 396-2039.

APPENDIX B

ASSUMPTIONS AND CALCULATIONS

Table C-1
PAR 1149 Increase in Degassing Hours

Source	Capacity	Content	Hours to Degas Under Rule 1149	Hours to Degas under PAR 1149	Increased Hours to Degas under PAR 1149
Existing	4,380,000	Gasoline	6.7	18.8	12.1
Existing	3,360,000	Gasoline	5.2	14.6	9.4
Existing	19,446,000	Crude	16.9	47.3	30.4
Existing	1,596,000	Crude	1.4	3.9	2.5
Existing	18,900,000	Crude	16.4	45.9	29.5
New AST	3,206,000	Xylene	N/A	7	7
New Pipeline	155,016	gasoline	N/A	6.2	6.2
New Pipeline	155,016	crude	N/A	3.4	3.4
Total hourly increase:					**100.5**

Worst Day Increased Propane Usage (@8.8 gal/hour) = 884 gal/hour

Table C-2
PAR 1149 Emission Factors

Description	VOC	Methane	NOx	SOx	CO	PM	PM2.5
LPG for ICE	1.8	0	35	0.35	25	5.0	5.0
LPG for TO	0.26	0.28	13	4.6	3.2	0.28	0.28

PM2.5 is 99.8 percent of PM10 for internal combustion of gaseous fuels in the CEIDARS Database
PM2.5 is 100 percent of PM10 for external combustion of gaseous fuels in the CEIDARS Database

Table C-3
PAR 1149 Emissions from Degassing Operations

Emission Increase (lb/day)	VOC	Methane	NOx	SOx	CO	PM	PM2.5
at 100% ICE use	1.6	0	31	0.31	22	4.4	4.4
at 100% TO use	0.23	0.25	11	4.1	2.8	0.25	0.25
at 69.2/30.8 T.O./ICE use	0.65	0.17	17	2.9	8.8	1.5	1.5

Emissions, lb/day = (Use, gal/day)/(1,000 gal) x EF, lb/1,000 gal

Table C-4
PAR 1149 Emissions from Diesel Truck Emissions

Addition Tank Trips

Description	No of Tanks	Annual Trips
New Tanks	470	94

Annual trips, trip/year = No of Tanks/10 years
Daily trips, trip/day = 2 trucks x (annual trips, trip/year)/(365 day/year)

Pipeline Trips

Description	Miles	Annual Trips
Pipeline	800	320

Annual trips, trip/year = Miles/5 mile/segment
Daily trips, trip/day =2 trucks x (annual trips, trip/year)/(365 day/year)

EMFAC2007 Emission Factors

Description	CO, lb/mile	NOx, lb/mile	VOC, lb/mile	SOx, lb/mile	CO2, lb/mile	PM10, lb/mile
Heavy-Duty Truck	0.0055	0.0356	0.0012	4.57E-05	4.22	0.0006

EMFAC2007, SCAQMD district

Mobile Emissions

~~Description~~	~~Annual Trips, trip/year~~	~~Daily Trips, trip/day~~	~~One-Way, mile/trip~~	~~CO, lb/day~~	~~NOx, lb/day~~	~~VOC, lb/day~~	~~SOx, lb/day~~	~~CO2, tons/yr~~	~~PM10, lb/day~~	~~PM2.5, lb/day~~
~~Heavy-Duty Truck~~	~~414~~	~~6~~	~~40~~	~~2.65~~	~~17.1~~	~~0.59~~	~~0.0219~~	~~70~~	~~0.309~~	~~0.284~~

Description	**Annual Trips, trip/year**	**Daily Trips, trip/day**	**One-Way, mile/trip**	**CO, lb/day**	**NOx, lb/day**	**VOC, lb/day**	**SOx, lb/day**	**CO2, tons/yr**	**PM10, lb/day**	**PM2.5, lb/day**
Heavy-Duty Truck	414	7	40	3.09	20.0	0.69	0.0256	70	0.361	0.332

Emissions, lb/day = daily trips, trips/day x one-way, mile/trip x EF, lb/mile x 2 one-way trips
Emissions, ton/year = annual trips, trips/year x one-way, mile/trip x EF, lb/mile x 2 one-way trips
PM2.5 is 92 percent of PM10 for on-road diesel combustion in the CEIDARS Database

Table C-5
Summary of PAR 1149 Operational Emissions

Description	**CO, lb/day**	**NOx, lb/day**	**VOC, lb/day**	**SOx, lb/day**	**PM10, lb/day**	**PM2.5, lb/day**
Control Technology	8.8	17	0.65	2.9	1.5	1.5
Mobile Source	3.1	20	0.69	0.026	0.36	0.33
Total	12	37	1.3	2.9	1.9	1.9

Table C-6
PAR 1149 Daily Construction Emissions

Construction Activity

Construction Schedule

Equipment Type[a]	**No. of Equipment**	**hr/day**	**Crew Size**
Tractors/Loaders/Backhoes	1	1	3
Generator Sets	1	4	

Construction Equipment Combustion Emission Factors

	CO	**NOx**	**PM10**	**VOC**	**SOx**	**CO2**
Equipment Type[c]	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Tractors/Loaders/Backhoes	0.406	0.775	0.120	0.060	0.001	66.806
Generator Sets	0.346	0.698	0.107	0.043	0.001	60.993

Construction Vehicle (Mobile Source) Emission Factors

	CO	**NOx**	**PM10**	**VOC**	**SOx**	**CO2**
	lb/mile	lb/mile	lb/mile	lb/mile	lb/mile	lb/mile
Heavy-Duty Truck[d]	0.01361368	0.04458017	0.00215635	0.00351579	0.00004136	4.210671446

On-Site Number of Trips and Trip Length

Vehicle	**No. of One-Way Trips/Day**	**One-Way Trip Length (miles)**
Haul Trucks	2	40

Table C-6 (Continued)
PAR 1149 Daily Construction Emissions

Incremental Increase in Onsite Idling Emissions from Onroad Mobile Vehicles

Equation: Emission Factor (lb/hr) x No. of Equipment x Work Day (hr/day) = Onsite Construction Emissions (lb/day)

	CO	**NOx**	**PM10**	**VOC**	**SOx**	**CO2**
Equipment Type	lb/day	lb/day	lb/day	lb/day	lb/day	lb/day
Tractors/Loaders/Backhoes	0.41	0.77	0.12	0.06	0.001	67
Generator Sets	1.38	2.79	0.43	0.17	0.003	244
Total	**1.79**	**3.57**	**0.55**	**0.23**	**0.004**	**311**

Incremental Increase in Onsite Combustion Emissions from Onroad Mobile Vehicles

Equation: Emission Factor (lb/mile) x No. of One-Way Trips/Day x 2 x Trip length (mile) = Mobile Emissions (lb/day)

	CO	**NOx**	**PM10**	**VOC**	**SOx**	**CO2**
Vehicle	lb/day	lb/day	lb/day	lb/day	lb/day	lb/day
Flatbed Trucks	2.178	7.133	0.3450	0.563	0.007	674
Total	**2.18**	**7.13**	**0.345**	**0.563**	**0.007**	**674**

Total Incremental Combustion Emissions from Construction Activities

	CO	**NOx**	**PM10**	**VOC**	**SOx**	**CO2**
Sources	lb/day	lb/day	lb/day	lb/day	lb/day	lb/day
On-Site Emissions	**4.0**	**10.7**	**0.9**	**0.8**	**0.01**	**984**
Regional Significance Threshold	***550***	***55***	***150***	***75***	***150***	
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**N/A**

Table C-6 (Concluded)
PAR 1149 Daily Construction Emissions

Combustion and Fugitive Summary	**PM2.5 Fraction**[e]	**PM10** lb/day	**PM2.5** lb/day
Combustion (Offroad)	0.92	0.6	0.5
Combustion (Onroad)	0.96	0.345	0.333
Fugitive	0.21	0	0
Total		**0.90**	**0.84**
Regional Significance Threshold			**55**
Exceed Significance?			**NO**

Notes:
a) SCAQMD, estimated
c)CARB, Offroad http://www.aqmd.gov/ceqa/handbook/offroad/offroadEF07_25.xls
d) CARB, EMFAC2007 http://www.aqmd.gov/ceqa/handbook/onroad/onroadEFHHDT07_26.xls
e) ARB's CEIDARS database PM2.5 fractions - construction dust category for fugitive and diesel vehicle exhaust category for combustion.

Table C-7~~5~~
Summary of PAR 1149 Criteria Emissions

~~**Description**~~	~~**CO, lb/day**~~	~~**NOx, lb/day**~~	~~**VOC, lb/day**~~	~~**SOx, lb/day**~~	~~**PM10, lb/day**~~	~~**PM2.5, lb/day**~~
~~Control Technology~~	~~9~~	~~17~~	~~0.65~~	~~2.9~~	~~1.5~~	~~1.5~~
~~Mobile Source~~	~~2.6~~	~~17~~	~~0.59~~	~~0.022~~	~~0.31~~	~~0.28~~
~~Total~~	~~11~~	~~34~~	~~1.2~~	~~2.9~~	~~1.8~~	~~1.8~~
~~Significance Threshold~~	~~550~~	~~55~~	~~55~~	~~150~~	~~150~~	~~55~~
~~Significant?~~	~~No~~	~~No~~	~~No~~	~~No~~	~~No~~	~~No~~

Description	**CO, lb/day**	**NOx, lb/day**	**VOC, lb/day**	**SOx, lb/day**	**PM10, lb/day**	**PM2.5, lb/day**
Construction	4.0	11	0.59	1.1	0.59	0.56
Operational	12	37	1.3	2.9	1.9	1.9
Total	16	48	1.9	4.1	2.5	2.4
Significance Threshold	550	55	55	150	150	55
Significant?	No	No	No	No	No	No

Table 8
GHG Emissions from Oxyacetylene

C_2H_2 Usage, cft/day	Density, lb/ft3	Conversion, g/lb	C_2H_2 Mol Weight, g/mol	C_2H_2 Usage, mol/day
70	0.0686	453.59	26.04	84

Usage, mol/day = (usage, cft/day x density, lb/ft3 x conversion, g/lb)/(molecular weight, g/mol)

C_2H_2 Usage, mol/day	CO2, mol/day	CO2 Mol Weight, g/mol	Conversion, g/lb	CO2, lb/day
84	167	44	453.59	16

$2C_2H_2 + 5O_2 \rightarrow 4CO_2 + 2H_2O$, therefore two moles of CO_2 are generated from every C_2H^2 mole.
CO_2, lb/day = CO_2, mole/day x MW, g/mol x conversion, g/lb

CO2, lb/day	Cutting/ Welding Days	Number of Tanks	Construction Period	CO2, lb/year
16	4	14	4	227

CO2, lb/project = CO2, lb/day x cutting/welding days x number of tanks

Table C-9~~5~~
Summary of PAR 1149 GHG Emissions

~~Description~~	~~CO2, ton/yr~~	~~CO2, metric ton/yr~~
~~Control Technology~~[a]	~~1,217~~	~~1,198~~
~~Mobile Source~~	~~70~~	~~69~~
~~Total~~	~~1,287~~	~~1,267~~

Table C-9~~5~~ (Continued)
Summary of PAR 1149 GHG Emissions

Description	CO, lb/year	CO, ton/year	CO, metric ton/year
Construction - Mobile and Construction[a]	13,783	6.9	6.3
Construction Oxyacetylene[a]	227	0.11	0.10
Operational – Degassing[b]	2,710,521	1,355	1,229
Operational - Mobile	139,833	70	63
Total CO2 emissions	2,864,364	1,432	1,299

a) Based on four days of cutting and welding and construction over four years.

b) Control Technology Annual CO2 from Table 7 – Related Increase in Criteria Pollutants and Greenhouse Gas Emissions in the Draft Staff Report for Proposed Amended Rule 1149 – Storage Tank and Pipeline Cleaning and Degassing, February 2008.

Table C-9~~6~~
Acute Health Risk from ICE

Code	Pollutant	CAS NO.	Usage, 1,000 gal/hr	4 Stroke-Rich Burn EF, lb/1,000 gal	4 Stroke-Rich Burn Qhr, lb/hr	Acute REL, (µg/m3)	X/Qhr ([µg/m3]/[lb/hr])	4 Stroke-Rich Burn HI
2	Benzene	71432	0.0176	0.143	0.0025168	28000	2000	0.0001798
4	1,3-Butadiene	106990	0.0176	0.06	0.001056	0	2000	
6	Carbon Tetrachloride	56235	0.0176	0.0016	2.816E-05	1900	2000	2.964E-05
9	Ethylene Dibromide	106934	0.0176	0.00193	3.397E-05	0	2000	
10	1,2-Dichloroethane	107062	0.0176	0.00102	1.795E-05	0	2000	
12	Formaldehyde	50000	0.0176	1.86	0.032736	94	2000	0.6965106
16	Methylene Chloride	75092	0.0176	0.00373	6.565E-05	68000	2000	1.931E-06
19	2-Methylnaphthalene	91576	0.0176	0	0	0	2000	
19	Acenaphthene	83329	0.0176	0	0	0	2000	
19	Acenaphthylene	208968	0.0176	0	0	22000	2000	0
19	Anthracene	120127	0.0176	0	0	22000	2000	0
19	Benz(a)anthracene	56553	0.0176	0	0	0	2000	
19	Benzo(a)pyrene	50328	0.0176	0	0	0	2000	
19	Benzo(b)fluoranthene	205992	0.0176	0	0	22000	2000	0
19	Benzo(e)pyrene	192972	0.0176	0	0	22000	2000	0

Table C-9~~6~~ (Continued)
Acute Health Risk from ICE

Code	Pollutant	CAS NO.	Usage, 1,000 gal/hr	4 Stroke-Rich Burn EF, lb/1,000 gal	4 Stroke-Rich Burn Qhr, lb/hr	Acute REL, (µg/m3)	X/Qhr ([µg/m3]/ [lb/hr])	4 Stroke-Rich Burn HI
19	Benzo(g,h,i)perylene	191242	0.0176	0	0	22000	2000	0
19	Benzo(k)fluoranthene	207089	0.0176	0	0	22000	2000	0
19	Chrysene	218019	0.0176	0	0	22000	2000	0
19	Fluoranthene	206440	0.0176	0	0	22000	2000	0
19	Fluorene	86737	0.0176	0	0	0	2000	
19	Indeno(1,2,3-c,d)pyrene	193395	0.0176	0	0	22000	2000	0
19	Naphthalene	91203	0.0176	0.00879	0.0001547	0	2000	
19	Perylene	198550	0.0176	0	0	22000	2000	0
19	Phenanthrene	85018	0.0176	0	0	0	2000	
19	Pyrene	129000	0.0176	0	0	22000	2000	0

Table C-9~~6~~ (Concluded)
Acute Health Risk from ICE

Code	Pollutant	CAS NO.	Usage, 1,000 gal/hr	4 Stroke-Rich Burn EF, lb/1,000 gal	Qhr, lb/hr	Acute REL, (µg/m3)	X/Qhr ([µg/m3]/ [lb/hr])	HI
21	Vinyl Chloride	75014	0.0176	0.00065	1.144E-05	68000	2000	3.365E-07
24	1,1,2,2-Tetrachloroethane	79345	0.0176	0.00229	4.03E-05	0	2000	
25	1,1,2-Trichloroethane	79005	0.0176	0.00138	2.429E-05	0	2000	
26	1,2,4-Trimethylbenzene	95636	0.0176	0	0	0	2000	
27	1,2-Dichloropropane	78875	0.0176	0.00118	2.077E-05	68000	2000	6.108E-07
28	1,3-Dichloropropene	542756	0.0176	0.00115	2.024E-05	22000	2000	1.84E-06
29	Acetaldehyde	75070	0.0176	0.252	0.0044352	68000	2000	0.0001304
30	Acrolein	107028	0.0176	0.238	0.0041888	0	2000	
32	Ammonia	7664417	0.0176	0.3	0.00528	22000	2000	0.00048
35	Chloroform	67663	0.0176	0.00124	2.182E-05	28000	2000	1.559E-06
40	Ethylbenzene	100414	0.0176	0.00224	3.942E-05	0	2000	
44	n-Hexane	110543	0.0176	0	0	22000	2000	0
51	Methanol	67561	0.0176	0.277	0.0048752	28000	2000	0.0003482
66	Styrene	100425	0.0176	0.00108	1.901E-05	0	2000	
68	Toluene	108883	0.0176	0.0505	0.0008888	22000	2000	0.0000808
70	Xylene	1330207	0.0176	0.0176	0.0003098	22000	2000	2.816E-05
								0.697794

Assumes two engines are used
Usage, 1,000 gal/hr = (8.8 gal/hr * 2 engines)/1,000
4 Stroke-Rich Burn EF, lb/1,000 gal from Annual Emissions Reporting Program
Qhr, lb/hr = usage, 1,000 gal/hr x 4 Stroke-Rich Burn EF, lb/1,000 gal
X/Qhr, ([µg/m3]/ [lb/hr]) from Table 6 of the Risk Assessment Procedures for Rules 1401 and 212, stack ≥ 14 to 24 foot and receptors within 25 meters of source.
4 Stroke-Rich Burn HI = (Qhr, lb/hr)/X/Qhr, ([µg/m3]/ [lb/hr])

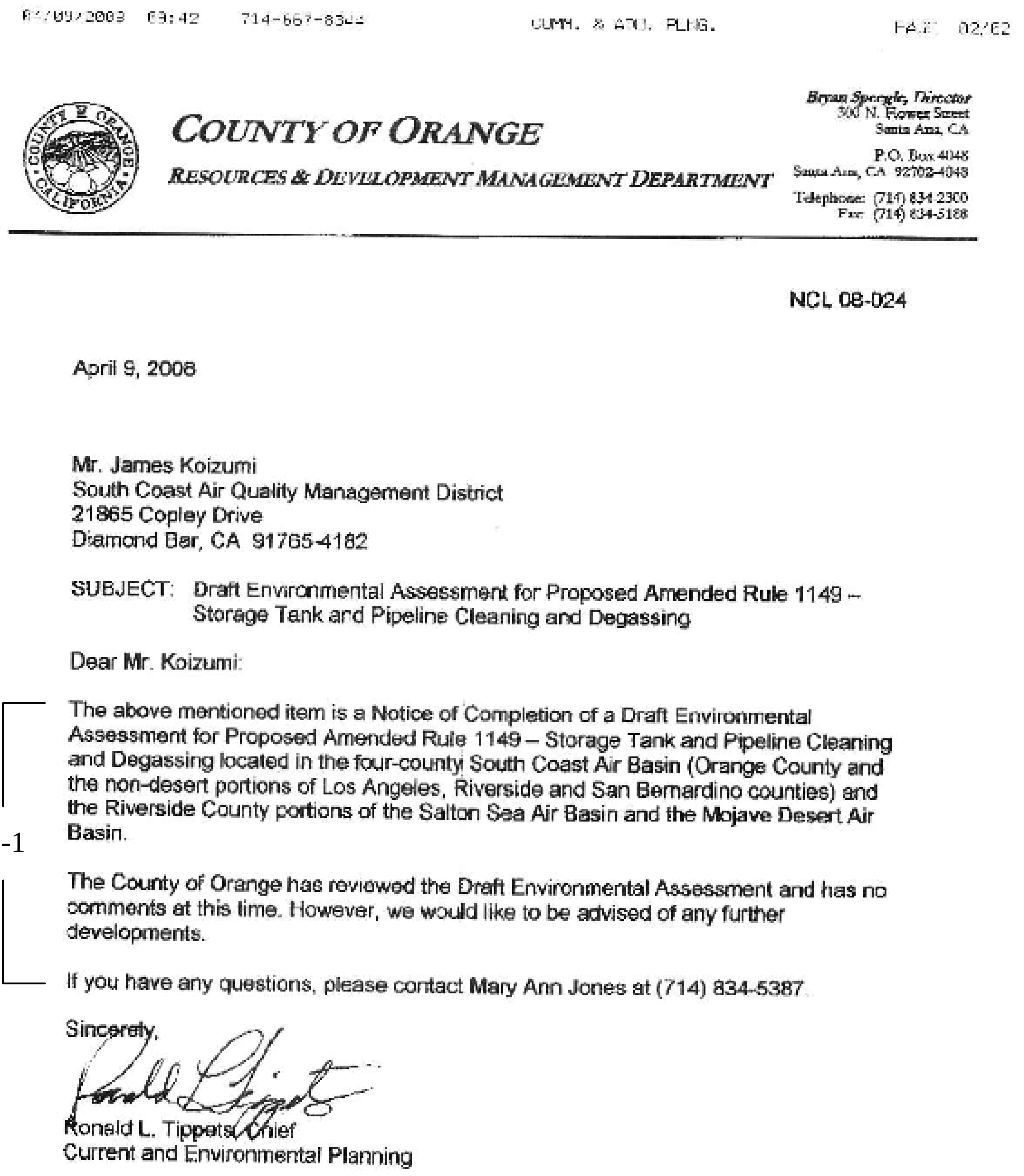
Table C-10~~7 (~~
Acute Health Risk from Afterburners

Code	POLLUTANT	CAS NO.	EF <10 MMBTU/HR EF, lb/1,000 gal	10-100 MMBTU/HR EF, lb/1,000 gal	Usage, 1,000 gal/hr	Qhr, lb/hr	Acute REL, (µg/m3)	X/Qhr ([µg/m3]/ [lb/hr])	HI
2	Benzene	71432	0.00071	0.00051	0.0176	0.000012496	28000	2000	8.92571E-07
12	Formaldehyde	50000	0.00151	0.00109	0.0176	0.000026576	94	2000	0.000565447
19	PAHs (excluding Naphthalene)	1151	0.00001	0.00001	0.0176	0.000000176	0	2000	
19	Naphthalene	91203	0.00003	0.00003	0.0176	0.000000528	0	2000	
29	Acetaldehyde	75070	0.00038	0.00028	0.0176	0.000006688	68000	2000	1.96706E-07
30	Acrolein	107028	0.00024	0.00024	0.0176	0.000004224	0	2000	
32	Ammonia	7664417	0.3	0.3	0.0176	0.00528	22000	2000	0.00048
40	Ethyl benzene	100414	0.00084	0.00061	0.0176	0.000014784	0	2000	
44	Hexane	110543	0.00056	0.00041	0.0176	0.000009856	22000	2000	0.000000896
68	Toluene	108883	0.00325	0.00235	0.0176	0.0000572	22000	2000	0.0000052
70	Xylene	1330207	0.00241	0.00175	0.0176	0.000042416	22000	2000	0.000003856
									0.001056488

Assumes two afterburners are used
Usage, 1,000 gal/hr = (8.8 gal/hr * 2 engines)/1,000
EF <10 MMBTU/HR EF, lb/1,000 gal from Annual Emissions Reporting Program
Qhr,lb/hr = Usage, 1,000 gal/hr x EF <10 MMBTU/HR EF, lb/1,000 gal
X/Qhr, ([µg/m3]/ [lb/hr]) from Table 6 of the Risk Assessment Procedures for Rules 1401 and 212, stack ≥ 14 to 24 foot and receptors within 25 meters of source.
HI = (Qhr, lb/hr)/X/Qhr, ([µg/m3]/ [lb/hr])

APPENDIX C

COMMENT LETTER AND RESPONSE TO COMMENT



COUNTY OF ORANGE
RESOURCES & DEVELOPMENT MANAGEMENT DEPARTMENT

Bryan Speegle, Director
300 N. Flower Street
Santa Ana, CA

P.O. Box 4048
Santa Ana, CA 92702-4048

Telephone: (714) 834-2300
Fax: (714) 834-5188

NCL 08-024

April 9, 2008

Mr. James Koizumi
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765-4182

SUBJECT: Draft Environmental Assessment for Proposed Amended Rule 1149 – Storage Tank and Pipeline Cleaning and Degassing

Dear Mr. Koizumi:

The above mentioned item is a Notice of Completion of a Draft Environmental Assessment for Proposed Amended Rule 1149 – Storage Tank and Pipeline Cleaning and Degassing located in the four-county South Coast Air Basin (Orange County and the non-desert portions of Los Angeles, Riverside and San Bernardino counties) and the Riverside County portions of the Salton Sea Air Basin and the Mojave Desert Air Basin.

1-1

The County of Orange has reviewed the Draft Environmental Assessment and has no comments at this time. However, we would like to be advised of any further developments.

If you have any questions, please contact Mary Ann Jones at (714) 834-5387.

Sincerely,

Ronald L. Tippets

Ronald L. Tippets, Chief
Current and Environmental Planning

Responses to Comment Letter #1
County of Orange
April 9, 2008

Response 1-1
SCAQMD staff understands that the County of Orange has no comments on the Draft EA. SCAQMD staff thanks the County of Orange for their interest in PAR 1149. The proposal will be presented to the SCAQMD Governing Board at the May 2, 2008 meeting.

Exhibit P

NATURAL RESOURCES DEFENSE COUNCIL

July 1, 2013

Via Fax to
City of Benicia Community Development Department
Attn: Amy Million
250 East L Street
Benicia, CA 94510
Fax: (707) 747-1637

Re: Notice of Intent to Adopt a Mitigated Negative Declaration for the Valero Crude by Rail Project

Dear Ms. Million:

On behalf of the Natural Resources Defense Council (NRDC), which has over 1.4 million members and activists, 250,000 of whom are Californians and approximately 100 of whom reside in Benicia, we submit the following comments on the Notice of Intent to Adopt a Mitigated Negative Declaration for the Valero Crude by Rail Project. The Notice of Intent for the project was issued on May 28, 2013, and indicated that the public comment period closes on July 1, 2013. Valero applied for a land use permit from the City of Benicia in December of 2012 to allow Valero to receive crude oil by train in quantities up to 70,000 barrels per day, in 100 rail cars per day.

Although the May 31, 2013 Initial Study/Mitigated Negative Declaration [IS/MND] on the Valero Crude by Rail Project assumed the project would cause no significant unmitigated effects on the environment, the IS/MND failed to consider all potential impacts. Our evaluation of the Project, as well as that of two independent experts retained by NRDC to evaluate the project, indicates that it will likely result in significant environmental impacts that have been neither discussed in the Initial Study nor mitigated under the IS/MND. Our comments below focus on air quality, public health, public safety, noise, general hazards and ecological risks.[1]

Because this Project could result in significant impacts to the environment, an Environmental Impact Report [EIR] must be prepared and circulated for public comment before the City may lawfully approve the project. Any significant impacts revealed by the EIR should be thoroughly analyzed and fully mitigated.

I. Air Quality and Public Health Impacts

The two key premises of the IS/MND's air quality analysis—that the new "North American-sourced crudes" received by the refinery as a result of the project will have a sulfur

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[1] Selected sources cited have been provided to the City of Benicia in hard copy. All sources cited in NRDC's comments and in the expert reports will be provided in CD to follow.

www.nrdc.org
111 Sutter Street
20th Floor
San Francisco, CA 94104
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NEW YORK · WASHINGTON, DC · LOS ANGELES · CHICAGO · BEIJING

content and density similar to the refinery's current slate, and that as a result, air emissions will not significantly change—is both unsupported and demonstrably wrong. The range of sulfur contents and densities projected for the new crude slate is wide, and air impacts could vary substantially within that range. Even more importantly, air emissions from crude refining depend on a host of characteristics other than sulfur content and density, and likely changes in those other characteristics are not disclosed or discussed by the IS/MND at all. Nor are other potentially significant air impacts, as further discussed below. The IS/MND thus fails to recognize the full suite of potential air quality and public health impacts of this project or provide any meaningful mitigation for those impacts.

No mitigation is included for the operational phase of this project. The operation of this project has very serious implications for air quality and public health that are not discussed in the IS/MND because the IS/MND fails to consider the appropriate scenarios of crude oils that may be transported by rail.

Valero's application states that "[t]he crude oil to be transported by rail cars is expected to be of similar quality compared to existing crude oil imported by marine vessel" and that the Project would not result in changes in refinery emissions. The May 31, 2013 IS/MND also assumes that there would be no significant change in crude oil slate due to the Project and no change in refinery emissions. But neither Valero's application nor the IS/MND provide data, let alone any analysis, sufficient to support these assumptions.

We have included as attachments to our comment letter, two expert reports that evaluate whether this Project would impact the crude oil slate or refinery emissions. The first report, by The Goodman Group, discusses changes to the refinery's crude slate that would likely occur due to the Crude by Rail Project. The report concludes that, although much of the relevant information needed to evaluate the proposed Project's exact effect on crude oil slate was not made publically available by either Valero or the City of Benicia, the Project is likely to significantly affect crude quality. In particular, the project is likely in the long-term to facilitate the refinery's use of Canadian tar sand crudes blended with diluent or "DilBits."

The second report, by Dr. Phyllis Fox, concludes that Canadian tar sand crudes blended with diluent have the potential to significantly change the profile of and increase air emissions compared to current crude slates. These changes may be, and indeed are likely to be, significant. The transport and refining of dilbits could significantly increase emissions of a wider range of pollutants including but not limited to volatile organic compounds (VOCs); hazardous air pollutants, including benzene and lead; and highly odiferous sulfur compounds. This additional pollution would degrade ambient air quality, adversely affect the health of workers and residents around the subject facilities, and create public nuisance odors. Further, the high acid levels in these crudes would accelerate corrosion of refinery components, contributing to equipment failure and increased accidental releases.

Unfortunately, contrary to CEQA's goals of public disclosure and evaluation, the IS/MND does not disclose enough specific information about the chemical composition of the crudes that would be imported and the crudes that would be displaced to fully assess crude quality changes and resulting air quality and other impacts. The number and nature of the deficiencies are so substantial that the IS/MND should be withdrawn. The City should prepare an EIR with a complete Project description and a thorough environmental impact analysis.

The minor mitigations included for the construction component of the project amount to little more than dust control. The construction phase of the project should require all trucks, construction equipment and any other equipment utilizing a diesel engine to meet the latest and cleanest U.S. EPA emission standards or be retrofitted with exhaust controls to achieve similar emission reductions.

A. Increased Air Emissions Due to Heavier, Lower Quality Crude Oil

The IS/MND fails to disclose or quantify the increases in emissions that could and likely would result from modifications to the crude slate at the Valero refinery that could and likely would result from the Crude by Rail Project. As noted in the concurrently submitted expert report of The Goodman Group, publicly disclosed information supports a finding that the rail project could foreseeably lead to replacing as much as 40% or more of the refinery's current crude slate (70,000 barrels per day) with tar sands crudes. This would make the refinery's overall crude slate heavier, increase emissions, and result in significant environmental impacts.

The CEQA baseline that must be considered for this project is the current slate of crude oil. Current refinery conditions and current air emissions must be analyzed. 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. However, even if emissions increases from the Crude by Rail Project fell within the limits of existing permits and plans, those increases may still be significant for purposes of CEQA. 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. The California Supreme Court specifically concluded, regarding the ConocoPhillips refinery in Los Angeles, that the pre-existing permits did not establish the baseline for CEQA analysis. *Communities for a Better Environment v. South Coast Air Quality Management District (2010) 48 Cal.4th 310.*

Thus, even if the emission increases identified below, when fully analyzed, fell within existing permit limits, or potential future emissions analyzed with respect to other projects,[2] this would 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. (And even if those increased emissions had

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[2] Although the IS/MND neglected to discuss the Valero Improvement Project (VIP) that began in 2002 and remains in progress, that Project envisioned process changes designed to facilitate the import and processing of much higher sulfur and heavier crudes than the current slate. Documents related to the VIP are relevant to our comments because those VIP documents articulate Valero's clear intent to process much dirtier crudes, and provide some insight into the additional energy usage required and potential increased air emissions.

been considered earlier, they would now have to be evaluated now within the regulatory and other framework on the ground now.)

In fact the potential air emissions increases related to this project 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 fails to evaluate these potential emission increases and their environmental consequences, yet we find that they are significant and unmitigated, requiring the preparation of an EIR.

1) *Changes in Crude Slate and Chemical Composition*

The air quality impacts of refining North American-sourced crudes such as tar sands depends on the chemical and physical composition of the refinery slate with tar sands crude compared to the current slate. The current slate includes very little tar sands, from 0.5% to 2% of the Refinery total crude slate over the period 2010 to 2012. 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 with a dramatically different chemical composition, which will change the emissions profile and cause significant increases in emissions of some pollutants compared to the emissions from the Refinery's current crude slate.[3]

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.[4] These pollutants contribute to smog, soot, acid rain, and odors that affect residents nearby.

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[3] 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, *available at* http://link.springer.com/book/10.1007/978-1-4684-4133-8/page/1;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; 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.

[4] 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.

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.[5] The type of data required to evaluate emissions would require, at a minimum, the following information:

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

Valero is likely to have access to the crude assay or "fingerprint" of the oil, but it was not made available to the public, foreclosing any meaningful public review. The IS/MND 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, asserting that there would be no change. 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 and they would arrive at the Refinery with the largest discount relative to other crudes.

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[5] 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.

Although specific information is lacking, significant impacts can reasonably be expected from including tar sands crudes in the crude slate. The IS/MND claims that new "North American-sourced crudes" will not significantly change the range of sulfur content and density of the crude slate; however, it is possible and probable for the range of API and sulfur reported in the IS/MND to remain similar, yet with relatively small shifts in the average levels of sulfur and density and with major shifts in other properties, for emissions to increase. Essentially, the premise of the IS/MND that the composition of the crude slate will not change and thus will not impact air emissions, is inherently false.

For example, sulfur content of crude oils represents 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 total sulfur expressed as a percent of the crude oil by weight. Although a range in the total sulfur content of rail-imported crude and the current crude slate may appear similar, even a small increase in total sulfur content can have profound impacts, and the composition of sulfur species also matters. A minor increase in sulfur content was reported by the Federal Chemical Safety Board (CSB) as a major contributing factor in the recent (August 2012) catastrophic fire at the Chevron Richmond Refinery in California.

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.[6] 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.

The specific chemicals in crude oil also 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 IS/MND failed to consider these finer details that have important implications for air quality and public health, and thus, failed to satisfy the disclosure requirements of CEQA and failed to analyze relevant impacts.

2) *Heavier Crudes Require More Processing*

Canadian tar sands bitumen is distinguished from conventional petroleum by the small concentration of low molecular weight hydrocarbons and the abundance of high molecular

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

weight polymeric material.[7] Crudes derived from Canadian tar sands bitumen—DilBits, Synthetic crude oils (SCOs) and the combination of the two (SynBits)—are heavier, i.e., have larger, more complex molecules such as asphaltenes,[8] some with molecular weights above 15,000.[9] They 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. The increases in fuel consumption also releases increased amounts of NO_x, SO_2, VOCs, CO, PM10, PM2.5, and HAPs as well as greenhouse gas emissions (GHG). The IS/MND fails to analyze these impacts of crude composition on the resulting emissions from generating increased amount of these utilities.

a. Higher Concentrations of Asphaltenes and Resins

The severity (e.g., temperature, amount of catalyst, hydrogen) of hydrotreating crude oil in a refinery 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.[10] 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.[11]

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[7] 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.

[8] 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.

[9] 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.

[10] 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.

[11] See, for example, the discussion of hydrotreating and hydrocracking of Athabasca tar sands cuts in. Gary R. Brierley, Visnja A. Gembicki, and Tim M. Cowan, Changing Refinery Configurations for Heavy and Synthetic Crude Processing, 2006, pp. 11-17. Available at:

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.[12] 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 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.[13]

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.[14] 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.

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https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BA07DE342-E9B1-402A-83F7-36B18DC3DD05%7D&documentTitle=5639138.

[12] 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.

[13] 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.

[14] Turini et al. Processing Heavy Crudes in Existing Refineries, prepared for AIChE Spring Meeting, Chicago, IL 2011, p. 9.; available at: http://www.aiche-fpd.org/listing/112.pdf

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.[15] Thus, much more hydrogen per barrel of feed and higher temperatures would be required to remove the larger amounts of these chemicals. 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.[16]

Canadian tar sands crudes generally have higher nitrogen content, 3,000 to >6,000 ppm[17] and specifically higher organic nitrogen content, particularly in the naphtha range, than other heavy crudes.[18] 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 emissions.

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. Some of these increased utility impacts were revealed in the VIP FEIR as of 2002. For example, the VIP FEIR indicated that the 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; (3) an increase in the firing rate of heaters and boilers of 400 MMBtu/hr; (4) an increase in the hydrogen capacity of 30 MMscf/day; and an increase in coker capacity of 5,000 BPD. 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

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[15] 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.

[16] 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.

[17] 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.

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

proposed change in crude slate would result in further increased impacts or if the changed regulatory framework requires more aggressive mitigation.

3) *Failure to Mitigate Air Emissions of Crudes*

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 (marine shipping may have been the focus 10 years ago, while the current development is for rail), 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 and the crude slate composition. The impacts of importing unidentified crudes by rail cannot be reasonably evaluated without considering and re-evaluating the impacts of the VIP modifications to the refinery.

a. VOC emissions of the Project are Significant and Unmitigated

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.[19] However, the dilbits that may now be imported with this Project would result in much higher VOC emissions than the originally anticipated heavier crude oil. These VOC emissions include large amounts of hazardous air pollutants, such as benzene, toluene and xylenes that result in significant health impacts, including elevated cancer risk.

Increased VOC emissions impacts have not been sufficiently analyzed for the current project. While we have focused our comments mainly on the reasonably foreseeable possibility that the Crude by Rail project will bring in heavy bitumen tar sands crudes, the IS/MND asserts that the imported crudes could include up to 70,000 BPD of light, low density crudes, which would create increased VOC emissions. 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, which similarly have significant VOC emissions increases associated with them, discussed below.

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[19] 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. See VIP RTC, p. IV-61. Supporting documents available at: http://www.ci.benicia.ca.us/index.asp?Type=B_BASIC&SEC=%7B737165B4-11C5-4974-9B0B-0AE4AC535ECC%7D.

The BAAQMD CEQA significance threshold for VOCs is 15 tons/year based on conservative 1999 guidance.[20] 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 tons/year or by 31 tons/year. 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, as explored further below.

b. Cumulative impacts of simultaneous construction of the VIP Project and the Crude By Rail Project are significant and unmitigated.

The Initial Study for the Crude by Rail Project estimated that the daily average construction exhaust emissions from building the rail terminal would be 51.9 lb/day.[21] The CEQA significance threshold is 54 lb/day.[22] Taken together with NOx emissions from the VIP Project, which is still being constructed, cumulative NOx emissions are likely to exceed the significance threshold. The last portion of the VIP project, the new Hydrogen Plant, will be under construction at the same time that the new rail terminal is being constructed. The VIP FEIR did not calculate construction emissions, as this was not required at the time, which is an example of the change in regulatory framework. If the NOx emissions from constructing the Hydrogen Plant would exceed 2.1 lb/day, cumulative NOx emissions from simultaneously constructing the Hydrogen Plant and the Crude by Rail project would be cumulatively significant. The IS/MND does not analyze cumulative NOx emissions and provides no support for an implicit assumption that NOx emissions from constructing the Hydrogen Plant would be less than 2.1 lb/day (i.e., 25 times less than from constructing the rail terminal). It is reasonable to assume—at least absent contrary analysis—that the emissions from constructing the Hydrogen Plant will exceed 2.1 lb/day (i.e., not be 25 times less than for constructing the rail terminal) and that the cumulative impacts of constructing the two projects simultaneously will exceed the significance threshold.

c. Emissions must be reduced to assure that regulatory levels are not exceeded.

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

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[20] Newer guidelines adopted in 2010 lowered the thresholds of significant for VOCs and other pollutants to 10 tons per year. However, the newer guidance is on hold due to ongoing litigation. See: http://www.baaqmd.gov/Divisions/Planning-and-Research/CEQA-GUIDELINES.aspx

[21] ESA, Valero Crude by Rail Project, Initial Study/Mitigated Negative Declaration, Use Permit Application 12PLN-00063, Prepared for City of Benicia, May 2013,Table 3-1.

[22] BAAQMD 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.

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:

- 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.[23] 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. [24] Coke contains many contaminants including lead.[25] 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 cumulative increase in coke fugitive emissions estimated in the VIP EIR and facilitated by the Crude by Rail Project are a significant public health impact.

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[23] See, e.g., VIP DEIR, p. 4.2-14.

[24] 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.

[25] For example, see a Material Safety Data Sheet for Petroleum Coke: http://www.tsocorp.com/stellent/groups/corpcomm/documents/tsocorp_documents/msdspetrocoke.pdf

Further, the VIP DEIR assumed health impacts from coke dust exposure would be mitigated by complying with the then-current PM10 and PM2.5 regulations.[26] 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 and heavy metal-laden coke dust, that could reasonably be expected to result from the Crude to Rail Project, could comply with these new standards, or that such compliance would mitigate lead health impacts, given CARB's zero threshold finding, or that other contaminants in coke dust would not pose a significant risk to public health.

B. Increased Air Emissions from Diluent

The majority of the crudes that will eventually be transported by rail will likely be a blend of bitumen and diluent due to their discounted price compared to conventional light sweet crudes. When heavy crude is shipped by pipeline, it needs to be diluted so that it will flow in the pipe, and this is similarly the case for un-heated railcars. We estimate that the Dilbit likely to be imported by this project will contain 20% to 30% diluent based on the description of the rail facility in the IS/MND.[27]

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 evaporates easily when exposed to ambient conditions, leaving behind the heavy ends, the vacuum gas oil (VGO) and residuum.[28] Thus, when a DilBit is released accidentally, it will generally create a difficult to cleanup spill as the heavier bitumen will be left behind.[29] 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 the more desirable

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[26] VIP DEIR, p. 4.8-14.

[27] Bitumen blended to pipeline specifications can be loaded on and off conventional rail tank cars like other light crudes. The amount of diluent depends on the type of rail tank car and design details of the offloading facilities. Although this information was not provided in the IS/MND, the document did discuss the use of 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.

[28] 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.

[29] 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.

middle range.[30] Thus, they yield very little middle distillate fuels, such as diesel, heating oil, kerosene, and jet fuel and much more coke, than other heavy crudes. A typical DilBit, for example, will have 15% to 20% by weight light material, 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 show major differences between DilBits and the crudes currently refined at Benicia.[31]

The large amount of light material in DilBits 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. It is unlikely that any other heavy crudes processed at the Refinery currently arrive with diluent, since EIA crude import data 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 HAPs 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 is reported on the website, www.crudemonitor.ca.[32] The specific diluents that would be used by the Project are unknown. However, the CrudeMonitor information indicates that several different types of diluents contain very high concentrations (based on 5-year averages) of the hazardous air pollutants

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[30] 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.

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

[32] 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.

(HAPs) benzene (5,200 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 12,400 ppm.[33] Similarly, the BTEX in synthetic crude oils (SCOs) ranges from 6,100 ppm to 14,100 ppm.[34] These are very high concentrations that were not considered in the emission calculations in the IS/MND 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 0.06 wt % or 0.6 wt % for the default value.[35] Thus, the IS/MND's assumptions as to benzene in fugitive emissions are inconsistent. The default crude oil speciation profile from the TANKS4.09d model reports benzene at 0.6 wt %.[36] Thus, the

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[33] 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) - 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.

[34] 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.

[35] See Appendix A.1 of the IS/MND (The Air Permit Application or Authority To Construct, “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.

[36] The profile, "Tanks_Crude_Speciation.xls" can be extracted from the TANKS409d model available at http://www.epa.gov/ttnchie1/software/tanks/ by using the "Data --> Speciation

IS/MND apparently lowered the benzene concentration in rail-imported crude oil by a factor of ten.[37] This contradicts published crude composition for the range of North American-sourced crudes that could be imported by the Project, as reviewed above and summarized in Table 1. The benzene value used in the IS/MND substantially underestimates the amount of benzene that would be present in tank and fugitive component emissions when processing either DilBits or Bakken crudes.

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 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.

Profiles --> Export" menu selection and choosing crude oil. This spreadsheet confirms that the default benzene level for crude oils is 0.6wt.%.

[37] The information in IS/MND Appendix A confirms that the lower value for benzene in crude, 0.06wt.%, was used to calculate benzene emissions.

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)[38] (wt.%)	Christina DilBit[39] (5-yr Avg) (wt.%)	Western Canadian Select[40] (5-yr Avg) (wt.%)	Bakken[41] 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).[42] Further, the IS/MND and underlying ATC fail to disclose that benzene emissions from fugitive components, when calculated using the correct benzene level (at least 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.[43] However, the benzene emissions used in this analysis apparently (the records lacks sufficient data to be certain) were underestimated by factors of 2.5 to 4.5 assuming DilBits and up to a factor of 17 for Bakken crudes. Although there is one DilBit with an unusually low benzene concentration of 0.06 wt.%, Borealis Heavy Blend, there is no evidence that this is the only DilBit that would be imported by rail.

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[38] 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.

[39] 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 44..

[40] 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 44..

[41] 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 44.

[42] ATC, p. 17-18 & Table 4-3.

[43] IS, p. II-15.

Although crude oil contains many different chemicals that are carcinogens, benzene is the only carcinogen included in the HAP emission calculations in the IS/MND.[44] 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 risks reported in the IS/MND in Table 3-3 can be adjusted for this error by multiplying that cancer risk by the benzene ratios reported above. With this correction, the cancer risk to the maximum exposed worker increases from the 4 in a million reported in the IS/MND to up to 20 in a million for DilBits and up to 76 in a million for Bakken crudes. For the maximum exposed residential receptor, the reported cancer risk increases from 2 in a million reported in the IS/MND to up to 10 in a million for DilBits and to 39 in a million for Bakken crudes. These cancer risk levels equal or exceed the assumed cancer significance threshold of 10 in a million. Thus, these are significant unmitigated impacts both to workers and nearby residents that were not disclosed in the IS/MND and are directly caused by the failure of the IS/MND to consider the composition of the crude that is being imported.

Information on diluents from the CrudeMontior also indicates 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.[45]

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 has experienced shortages of diluents, any material with a suitable thinning ability could be used, which could contain still other hazardous components, with the potential for even greater air quality and health impacts than discussed here.

C. Health Impacts of Chemical Constituents in DilBits

Heavy bitumen tar sands and diluents are composed of hundreds of chemicals with known health impacts. Below is a summary of the health impacts of some of those hazardous compounds associated with refining dirtier crude oils. Many of these compounds present significant hazards to human health at varying levels of exposure.

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[44] IS/MND, Appx. A.

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

1. Hydrogen Sulfide is a flammable and colorless gas that smells like rotten eggs. It is a broad spectrum poison that can be lethal at high concentrations. At low concentrations, hydrogen sulfide can cause irritation to the eyes, nose and throat. Additionally, exposure may result in incoordination, memory loss, hallucinations, personality changes, loss of sense of smell, cough, and shortness of breath; people with asthma may experience difficulty breathing. In occupational settings, workers have died from exposure to high levels of hydrogen sulfide.[46]

2. Mercaptans[47] are a large class of toxic compounds that generally have a strong and unpleasant odor even at very low concentrations. They are added in small amounts to natural gas to help detect gas leaks. Because they are extremely flammable, mercaptans present fire and explosion hazards in industrial processe. Exposure to mercaptans may cause irritation of the skin, eyes, and upper respiratory tract. All mercaptans negatively affect the central nervous system. Workers accidentally exposed to high levels of mercaptans experienced muscular weakness, nausea, dizziness, stupor, and uncounsciousness (narcosis).[48]

3. Thiophene[49] is a highly flammable and hazardous component of petroleum.[50] Exposure to thiophene results in adverse effects to the skin, eyes, nose and throat.[51] Workers breathing thiophene vapors generated from normal handling of the material may experience respiratory irritation, dizziness, fatigue, unconsciousness, loss of reflexes, lack of coordination, and vertigo. Long term exposure to thiophene may damage the liver, or produce asthma-like symptoms which may continue for months or years after exposure to the chemical stops.[52]

4. Benzothiophene[53] is a solid compound with an odor similar to naphthalene (mothballs). It is found in petroleum, and used primarily in industries such as pharmaceuticals and in

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[46] Agency for Toxic Substances and Disease Registry, *Toxicological Profile for Hydrogen Sulfide,* U.S. Department of Health and Human Services, July 2006.

[47] Mercaptans are also commonly known as thiols, thioalcohols, or sulphydrates.

[48] Stellman, Jeanne Mager, *Encyclopaedia of Occupational Health and Safety,* vol. 4,Geneva: International Labor Office, 1998.

[49] Thiophene is also called divinylene sulphide, thiacyclopentadiene, and thiofuran

[50] National Library of Medicine Hazardous Substances Databank , 'Thiophne', http://toxnet.nlm.nih.gov/cgi-bin/sis/search/f?./temp/~xlH0IB:1 (accessed June 2013)

[51] New Jersey Department of Health and Senior Services, ‘Thiophene Hazardous Substance Fact Sheet’, December 2000, http://nj.gov/health/eoh/rtkweb/documents/fs/1851.pdf (accessed June 2013)

[52] Santa Cruz Biotechnology, ‘ThiopheneMaterial Safety Data Sheet’ March 2009, http://datasheets.scbt.com/sc-251237.pdf (accessed June 2013)

[53] Benzothiophene is also known as thianaphthene, benzo(b)thiophene, 1-benzothiophene, 1-thiaindene, 2,3-benzothiophene, benzothiofuran, benzothiophen, thianaphtene, thianaphthen, thianaphthene, and thionaphthene

research.[54] A person exposed to benzothiophene may experience irritation of the eyes, skin, or respiratory tract.[55]

5. Methylsulfonic acid[56] is used in the process of refining petroleum. The general population is exposed through breathing outdoor air.[57] Methylsulfonic acid is harmful to humans and can irritate or burn the eyes, skin, and mucous membranes.[58] Inhaling methylsulfonic acid vapor is extremely destructive to the tissue of the mucous membranes and upper respiratory tract.[59]

6. Dimethyl sulfone[60,61] is an odorless, combustible liquid and vapor. If inhaled as a dust, it may cause respiratory irritation. It may also cause irritation to the eyes.[62]

7. Thiacyclohexane[63] is a sulfur containing component of crude oil. It is highly flammable, and exists in both liquid and vapor form. Exposure to thiacyclohexane may cause skin or eye irritation. At present, the short and long-term toxicity of this compound is not fully

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[54] Merck Index, 'Thianaphthene Structure Details', n.d., http://themerckindex.cambridgesoft.com/themerckindex/Forms/Search/ContentArea/ChemBioVizSearch.aspx?FormGroupId=200000&AppName=THEMERCKINDEX&AllowFullSearch=true&KeepRecordCountSynchronized=false&SearchCriteriaId=5&SearchCriteriaValue=95-15-8&CurrentIndex=0 (accessed June 2013)

[55] National Institue of Health Haz-Map Database, 'Benzothiophene Haz-Map Category Details', *Haz-Map*, n.d., http://hazmap.nlm.nih.gov/category-details?id=12230&table=copytblagents (accessed June 2013)

[56] Methylsulfonic acid is also called methanesulfonic acid

[57] National Library of Medicine Hazardous Substances Data Bank, 'Methanesulfonic Acid -', *Toxnet: Toxicology Data Network* http://toxnet.nlm.nih.gov/cgi-bin/sis/search/a?dbs+hsdb:@term+@DOCNO+5004 (accessed June 2013)

[58] Occupational Safety and Health Administration 'Methanesulfonic Acid Chemical Sampling Information', n.d., http://www.osha.gov/dts/chemicalsampling/data/CH_250710.html (accessed June 2013)

[59] National Library of Medicine Hazardous Substances Data Bank, 'Methanesulfonic Acid', http://toxnet.nlm.nih.gov/cgi-bin/sis/search/a?dbs+hsdb:@term+@DOCNO+5004 (accessed June 2013)

[60] Dimethyl sulfone is also known as methyl sulfone, methylsulfonylmethane, sulfonylbismethane, methane, sulfonylbis-, and dimethyl sulphone

[61] Dimethyl sulphone is commonly known as methylsulfonylmethane, or MSM, and used widely as a food supplement and medicine.

[62] Gaylord Chemical Corporation, 'Dimethyl Sulfone Material Safety Data Sheet', August 20, 2004, http://www.clean.cise.columbia.edu/msds/dimethylsulfoxide.pdf (accessed June 2013)

[63] Synonyms include thiapyran, tetrahydro- (4CI), thiopyran, tetrahydro- (6CI), pentamethylenesulfide, penthiophane, tetrahydro-2H thiopyran, tetrahydrothiapyran, tetrahydrothiopyran, thiacyclohexane, thiane. Search for this compound using thiane, or its CAS number 1613-51-0.

understood.[64]

8. Pentane[65] is a volatile organic compound (VOC) commonly found in natural gas and crude oil. Aside from the fact that is highly flammable—mixtures of pentane and air can be explosive—pentane has been identified as a central nervous system (CNS) depressant.[66] Exposure to pentane vapors can cause irritation to the eyes, skin, and respiratory system, as well as, nausea, vomiting, headaches, and dizziness.[67,68] Chronic or long-term exposure can result in anoxia, or a severe lack of oxygen to body organs and tissues.[69] Exposure to high levels of pentane can be deadly.[70]

9. Naphtha[71] is a highly flammable, toxic organic solvent distilled from petroleum with a wide range of industrial and commercial uses. Exposure to naphtha can cause headaches, dizziness, nausea, and vomiting.[72] Naphtha vapor is a central nervous system depressant as well as an irritant of the mucous membranes and the respiratory tract—exposure to high concentrations can cause fatigue, lightheadedness, and loss of consciousness.[73] Female workers exposed to naphtha experienced reproductive impacts in the form of disturbances in menstrual cycles, abnormal uterine bleeding, and a disturbance of the ovarian function.[74] Long-term exposure may cause damage to the liver, kidneys, blood, nervous system, and skin.[75] Naphtha contains benzene which is a known carcinogen. [76]

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[64] Alfa Aesar, 'Tetrahydrothiopyran Material Safety Data Sheet', June 2011, http://www.msds.com/servlet/B2BDocumentDisplay?document_version_nri=5175301&manuf_nri=704&manuf_name=&supplier_nri=704&page_number=1&search_source=centraldb&CLIENT_session_key=A736334_Kitty89&CLIENT_language=2 (accessed June 2013)

[65] Also known as n-Pentane, normal-Pentane

[66] National Library of Medicine Hazardous Substances Data Bank, 'PENTANE', http://toxnet.nlm.nih.gov/cgi-bin/sis/search/f?./temp/~mKkbnT:1 (accessed June 2013)

[67] NIOSH, 'CDC - NIOSH Pocket Guide to Chemical Hazards - n-Pentane', November 2010, http://www.cdc.gov/niosh/npg/npgd0486.html (accessed June 2013)

[68] NIOSH, 'n-Pentane International Chemical Safety Cards', October 1999 http://www.cdc.gov/niosh/ipcsneng/neng0534.html (accessed June 2013)

[69] National Library of Medicine Hazardous Substances Data Bank, 'Pentane', http://toxnet.nlm.nih.gov/cgi-bin/sis/search/f?./temp/~mKkbnT:1 (accessed June 2013)

[70] NIOSH, 'n-Pentane International Chemical Safety Cards', October 1999 http://www.cdc.gov/niosh/ipcsneng/neng0534.html (accessed June 2013)

[71] Like pentane, naphtha may be used as a diluent in heavy crude oils.

[72] New Jersey Department of Health and Senior Services, 'Naphtha Hazardous Substance Fact Sheet', April 2007, http://nj.gov/health/eoh/rtkweb/documents/fs/0518.pdf (accessed June 2013)

[73] National Library of Medicine Hazardous Substances Data Bank, 'Naphtha', http://toxnet.nlm.nih.gov/cgi-bin/sis/search/f?./temp/~PqjFcw:1 (accessed June 2013)

[74] National Library of Medicine Hazardous Substances Data Bank, 'Naphtha', http://toxnet.nlm.nih.gov/cgi-bin/sis/search/f?./temp/~PqjFcw:1 (accessed June 2013)

[75] Collection Care, 'Naphtha Material Safety Data Sheet', June 27, 2011, http://www.collectioncare.org/MSDS/naphthamsds.pdf (accessed June 2013)

BTEX: The following compounds (benzene, toluene, ethylbenzene, and xylene) are some of the VOCs found in petroleum.

10. Benzene is a common component of crude oil and gasoline, and a widespread environmental pollutant resulting mainly from refinery activity.[77] People are primarily exposed to benzene through breathing contaminated air. Benzene is a known carcinogen; long term exposure can cause leukemia.[78] Inhalation of high doses of benzene may impact the central nervous system leading to drowsiness, dizziness, irregular heartbeat, nausea, headaches, and depression.[79] Female workers experiencing high exposure levels over the course of many months experienced reproductive impacts, such as a decrease in the size of their ovaries. In animal studies, breathing benzene was associated with developmental effects such as low birth weight, delayed bone formation, and bone marrow damage.[80]

11. Toluene is a volatile organic compound (VOC) used widely in industry as a raw material and as a solvent. Toluene concentrations are highest in areas of heavy traffic, near gas stations and petroleum refineries. According to California's list of chemicals known to cause cancer or reproductive toxicity, toluene is listed as a developmental toxicant.[81] Similar to many organic solvents, toluene acts as a respiratory tract irritant, particularly at high air concentrations.[82] For this reason, it can be more harmful to people with asthma. A ubiquitous air pollutant, exposure to toluene constitutes a serious health concern as it has negative impacts on the central nervous system. Exposure to toluene can cause headaches, impaired reasoning, memory loss, nausea, impaired speech, hearing, and vision, amongst other health effects.[83] Long term exposure may damage the

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[76] New Jersey Department of Health and Senior Services, 'Naphtha Hazardous Substance Fact Sheet', April 2007, http://nj.gov/health/eoh/rtkweb/documents/fs/0518.pdf (accessed June 2013)

[77] Agency for Toxic Substances and Disease Registry, *Toxicological Profile for Benzene,* U.S. Department of Health and Human Services, August 2007.

[78] California EPA Office of Environmental Health Hazard Assessment, 'Chemicals Known to the State to Cause Cancer or Reproductive Toxicity', 2013, http://oehha.ca.gov/prop65/prop65_list/files/P65single052413.pdf (accessed June 2013)

[79] Agency for Toxic Substances and Disease Registry, *Toxicological Profile for Benzene,* U.S. Department of Health and Human Services, August 2007.

[80] Agency for Toxic Substances and Disease Registry, *Toxicological Profile for Benzene,* U.S. Department of Health and Human Services, August 2007.

[81] California EPA Office of Environmental Health Hazard Assessment, 'Chemicals Known to the State to Cause Cancer or Reproductive Toxicity', 2013, http://oehha.ca.gov/prop65/prop65_list/files/P65single052413.pdf (accessed June 2013)

[82] Agency for Toxic Substances and Disease Registry, *Toluene Toxicity*: *Case Studies in Environmental Medicine*, U.S. Department of Health and Human Services, Division of Toxicology and Environmental Medicine, February 2001, http://www.atsdr.cdc.gov/csem/toluene/docs/toluene.pdf (accessed June, 2013)

[83] Agency for Toxic Substances and Disease Registry, *Toluene Toxicity*: *Case Studies in Environmental Medicine,* U.S. Department of Health and Human Services, Division of

liver and kidneys.[84]

12. Ethylbenzene is a commonly occurring component of petroleum. Once refined, it is used in many consumer products such as gasoline, pesticides, varnishes and paints. Ethylbenzene has been recently classified as a possible human carcinogen by the International Agency for Research on Cancer (IARC)[85], and has been associated with a number of adverse health outcomes. Breathing high levels can cause dizziness as well as throat and eye irritation; chronic, low-level exposure over several months to years can result in kidney damage as well as hearing loss.[86]

13. Xylene[87] is a VOC in petroleum. Short term exposure to xylene may result in a number of adverse human health effects including irritation of the skin, eyes, nose and throat, difficulty breathing, damage to the lungs, impaired memory, and possible damage to the liver and kidneys. Long term exposure may affect the nervous system presenting symptoms such as headaches, lack of muscle coordination, dizziness, confusion, and loss of balance.[88] More serious long term health effects include memory impairment, red and white blood cell abnormalities, abnormal heartbeat (in laboratory workers), liver damage, mutagenesis (mutations of genes), reproductive system effects, and death due to respiratory failure.[89]

14. Polycyclic aromatic hydrocarbons (PAHs) are a group of over 100 different chemicals that are formed during incomplete combustion.[90,91,92] Infants and children are *especially*

Toxicology and Environmental Medicine, February 2001, http://www.atsdr.cdc.gov/csem/toluene/docs/toluene.pdf (accessed June, 2013)

[84] National Institute for Occupational Safety and Health, ‘Toluene’, *NIOSH Pocket Guide to Chemical Hazards*, 2010, http://www.cdc.gov/niosh/npg/npgd0619.html (accessed June 2013)

[85] Henderson, Leigh, David Brusick, Flora Ratpan, and Gauke Veenstra, ‘A Review of the Genotoxicity of Ethylbenzene’, *Mutation Research/Reviews in Mutation Research*, 635 (2007), 81-89 <doi:10.1016/j.mrrev.2007.03.001>

[86] Agency of Toxic Substances and Disease Registry, *Toxicological Profile for Ethylbenzene, ToxFAQs*, 2010, http://www.atsdr.cdc.gov/toxfaqs/tf.asp?id=382&tid=66 (accessed June 2013)

[87] Also known as dimethyl benzene

[88] Agency for Toxic Substances and Disease Registry, *Toxicological Profile for Xylene,* U.S. Department of Health and Human Services, August 2007.

[89] Zoveidavianpoor, M., A. Samsuri, and S. R. Shadizadeh, ‘The Clean Up of Asphaltene Deposits in Oil Wells’, *Energy Sources, Part A: Recovery, Utilization, and Environmental Effects*, 35 (2013), 22–31 <doi:10.1080/15567036.2011.619630>

[90] Salmon A.G. and Meehan T. Potential Impact of Environmental Exposures to Polycyclic Organic Material (POM) on Children’s Health, California Office of Environmental Health Hazard Assessment (OEHHA). http://www.oehha.ca.gov/public_info/public/kids/pdf/PAHs%20on%20Children's%20Health.pdf

susceptible to the hazards of PAHs, a class of known human mutagens, carcinogens, and developmental toxicants found in diesel exhaust.[93] Greater lifetime cancer risks result from exposure to carcinogens at a young age. These substances are known to cross the placenta to harm the unborn fetus, contributing to fetal mortality, increased cancer risk and birth defects.[94] Prenatal exposure to PAHs may also be a risk factor for the early development of asthma-related symptoms and can adversely affect children's cognitive development, with implications for diminished school performance.[95] Exposure of children to PAHs at levels measured in polluted areas can also adversely affect IQ.[96]

15. Lead is a well-known toxic heavy metal with diverse and severe health impacts.[97] In particular, lead is associated with neurological, hematological, and immune effects on children, and hematological, cardiovascular and renal effects on adults. Children are particularly sensitive to the effects of lead, including sensory, motor, cognitive and behavioral impacts. Cognitive effects of special concern include decrements in IQ scores and academic achievement, as well as attention deficit problems. Children in poverty and black, non-Hispanic children face higher exposures to lead and are consequently more susceptible to lead's health impacts. Reproductive effects, such as

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[91] Agency for Toxic Substances and Disease Registry, Public Health Statement for Polycyclic Aromatic Hydrocarbons (PAHs). August 1995.
http://www.atsdr.cdc.gov/PHS/PHS.asp?id=120&tid=25

[92] Perera FP. DNA Damage from Polycyclic Aromatic Hydrocarbons Measured by Benzo[a]pyrene-DNA Adducts in Mothers and Newborns from Northern Manhattan, The World Trade Center Area, Poland, and ChinaCancer Epidemiol Biomarkers Prev 2005;14(3):709–14.

[93] Salmon A.G. and Meehan T. "Potential Impact of Environmental Exposures to Polycyclic Organic Material (POM) on Children's Health," California Office of Environmental Health Hazard Assessment (OEHHA).
http://www.oehha.ca.gov/public_info/public/kids/pdf/PAHs%20on%20Children's%20Health.pdf
Agency for Toxic Substances and Disease Registry, Public Health Statement for Polycyclic Aromatic Hydrocarbons (PAHs). August 1995.
http://www.atsdr.cdc.gov/PHS/PHS.asp?id=120&tid=25.

[94] Perera FP. "DNA Damage from Polycyclic Aromatic Hydrocarbons Measured by Benzo[a]pyrene-DNA Adducts in Mothers and Newborns from Northern Manhattan, The World Trade Center Area, Poland, and China," *Cancer Epidemiology Biomarkers & Prevention* 14, no. 3 (2005):709–14.

[95] Perera FP, Rauh V, Tsai WY, Kinney P, Camann D, et al. "Effects of transplacental exposure to environmental pollutants on birth outcomes in amultiethnic population," *Environmental Health Perspective* 111 (2003): 201–205.
Perera FP et. al. "Effect of Prenatal Exposure to Airborne Polycyclic Aromatic Hydrocarbons on Neurodevelopment in the First 3 Years of Life among Inner-City Children," *Environmental Health Perspective* 114 (2006):1287–1292.

[96] Perera, FP et. al. "Prenatal Airborne Polycyclic Aromatic Hydrocarbon Exposure and Child IQ at Age 5 Years," *Pediatrics* 124 (2009):e195–e202.

[97] The lead health impacts are also derived from the final rule on the National Ambient Air Quality Standards for Lead, 73 Fed. Reg. 66964, 66975-76 (Nov. 12, 2008).

decreased sperm count in men and spontaneous abortions in women, have been associated with lead exposure. EPA has classified lead as a probable human carcinogen.

16. Nickel is associated with chronic dermatitis, respiratory impacts and potentially also reproductive impacts.[98] The EPA has classified nickel refinery subsulfide as a Group A, human carcinogen and nickel carbonyl as a Group B2, probable human carcinogen.

D. Accidental Releases

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 suggests that failure to perform required metallurgical upgrades can lead to catastrophic accidents.[99] 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. Crude oils with a TAN number greater than 0.5 mg KOH/g[100] are generally considered to be potentially corrosive and indicative of a level of concern. A TAN number greater than 1.0 mg KOH/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 mg KOH/g.[101]

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

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[98] Agency for toxic substances and Disease Registry, Public Health Statements, http://www.atsdr.cdc.gov/

[99] 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/.

[100] 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.

[101] www.crudemonitor.ca.

A crude slate change could result in corrosion from the particular suite of sulfur compounds or naphthenic acid content, which can lead 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, which 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. The IS/MND and VIP FEIR assume, however, that crude slate changes within the refinery design range of sulfur and API will not be a problem. In fact, although the sulfur composition at Chevron Richmond remained within the design range, they did change significantly over time.[102] 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. It also put workers at the unit in grave danger, with several escaping the gas cloud and inferno narrowly.

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.[103] 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.[104] These potential emissions must be evaluated and mitigated.

E. Unmitigated Impacts of Locomotive Emissions

The location of air emissions matters a great deal with respect to exposure levels and resulting health impacts to workers and residents. Yet the IS/MND fails to evaluate the likely pollutant exposure levels from locomotive activity of the proposed project compared to the marine shipping activity that would be replaced. In fact, the IS/MND states that the resulting emissions from rail activity will be lower than shipping. It is not clear whether that comparison accounted for all of the environmental regulations that shippers must now comply with

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[102] 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.").

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

[104] 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.

including much cleaner, lower sulfur marine fuels. Regardless, the slightly lower locomotive emissions reported are misleading because those emissions are occurring much closer to residential populations and thus may result in significantly higher exposure to toxic diesel exhaust.

The diesel engines in locomotives emit fine particulate matter (particles that are 2.5 microns or less in diameter or "PM2.5"), NOx, and VOCs along with many other toxic chemicals.[105] The soot in diesel exhaust—diesel PM—is especially toxic, not only due to the very small size of the soot particles, but also because these particles contain roughly 40 different toxic air contaminants, 15 of which are recognized carcinogens.[106] In fact, diesel PM itself has been identified as a carcinogen by the World Health Organization as well as the State of California,[107] which lists it as a "Toxic Air Contaminant." Dozens of studies have shown a high risk of lung cancer in occupations with high diesel exposures, including rail workers, truck drivers, and miners. Recent studies of miners indicate that the most heavily exposed workers have a risk of lung cancer approaching that of heavy smokers; studies also show that elevated risks of lung cancer apply not only to workers but to the general population in areas with high levels of diesel PM (*e.g.,* near freeways and busy freight corridors).[108]

Moreover, diesel pollution is estimated to contribute to roughly 60,000 or more premature deaths attributable to outdoor air pollution in the U.S.[109] People who live or go to school near

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[105] NRDC, Clean Cargo: A Guide to Reducing Diesel Air Pollution from the Freight Industry in Your Community, January 2013.

[106] Diesel exhaust contains the following toxic constituents: acetaldehyde, acrolein, aniline, antimony compounds, arsenic, benzene, beryllium compounds, biphenyl, bis[2-ethylhexyl]phthalate, 1,3-butadiene, cadmium, chlorine, chlorobenzene, chromium compounds, cobalt compounds, cresol isomers, cyanide compounds, dioxins and dibenzofurans, dibutylphthalate, ethyl benzene, formaldehyde, hexane, inorganic lead, manganese compounds, mercury compounds, methanol, methyl ethyl ketone, naphthalene, nickel, 4-nitrobiphenyl, phenol, phosphorus, POM including PAHs and their derivatives, propionaldehyde, selenium compounds, styrene, toluene, xylenes.
www.oehha.ca.gov/public_info/facts/dieselfacts.html;
www.oehha.ca.gov/air/toxic_contaminants/html/Diesel%20Exhaust.htm.

[107] www.oehha.ca.gov/prop65/prop65_list/files/P65single021712.pdf;
http://press.iarc.fr/pr213_E.pdf.

[108] Silverman, D.T., et al. "The Diesel Exhaust in Miners Study: A Nested Case-Control Study of Lung Cancer and Diesel Exhaust," Journal of the National Cancer Institute, Vol. 104, No. 11, June 6, 2012,
www.oxfordjournals.org/our_journals/jnci/press_releases/silvermandjs034.pdf.

[109] According to U.S. EPA, the following regulations avoid 52,000 annual premature deaths by 2030: 2001 highway Diesel (8,300); 2004 Nonroad Diesel (12,000), 2008 Locomotive/Marine (1,100), 2010 Emission Control Area (IMO ECA)/marine fuel (31,000). Assuming a 90% diesel PM reduction from each rule (though some of the rules yield 95% reductions), this means that diesel PM emissions led to roughly 58,200 premature deaths before the rules were in place. This is likely a significant under-estimate since several diesel PM sources are not accounted for here, such as light duty diesel trucks and stationary diesel engines.

rail yards face disproportionately higher exposure to diesel exhaust and associated health impacts, including increased risks of asthma and other respiratory effects, cancer, adverse birth outcomes, adverse impacts to the brain (including potentially higher risk of autism),[110] heart disease, and premature death.[111]

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[110] Autism spectrum disorders (ASDs) - a group of developmental disabilities that can cause significant social, communication and behavioral challenges - have increased 78 percent since 2002 to impact 1 in 88 children, according to the Centers for Disease Control and Prevention (CDC), *see* http://www.cdc.gov/Features/CountingAutism/. While experts are still working to better understand the risk factor, they agree that risk factors are not only genetic but environmental. Several recent studies in California have shown how air pollution contributes to autism, finding elevated risks in areas of elevated air pollution and in close proximity to freeways.

[111] Kim, J., et al. “Traffic-Related Air Pollution and Respiratory Health: East Bay Children’s Respiratory Health Study,” *American Journal of Respiratory and Critical Care Medicine* 2004;170:520-526.
McConnell, R., et al. “Childhood Incident Asthma and Traffic-Related Air Pollution at Home and School,” *Environmental Health Perspectives* 2010; 118(7):1021-1026.
Van Vliet, P., M. Knape, et al. “Motor Vehicle Exhaust and Chronic Respiratory Symptoms in Children Living Near Freeways,” *Environmental Research* 1997; 74(2):122-32.
Appatova, A.S., et al. “Proximal Exposure of Public Schools and Students to Major Roadways: A Nationwide U.S. Survey,” *Journal of Environmental Planning and Management* 2008; 51(5):631-646.
Nicolai, T., D. Carr, S.K. Weiland, H. Duhme, O. Von Ehrenstein, C. Wagner, and E. von Mutius. “Urban Traffic and Pollutant Exposure Related to Respiratory Outcomes and Atopy in a Large Sample of Children,” *European Respiratory Journal* 2003*;*21:956–963.
Brunekreef, B.; N.A. Janssen, J. de Hartog, H. Harssema, M. Knape, and P. van Vliet. “Air Pollution From Truck Traffic and Lung Function in Children Living Near Motorways,” *Epidemiology* 1997; 8(3):298-303.
Duhme, H., S.K. Weiland, et al. “The Association Between Self-Reported Symptoms of Asthma and Allergic Rhinitis and Self-reported Traffic Density on Street of Residence in Adolescents,“ *Epidemiology* 1996; 7(6):578-582.
Edwards, J., S. Walters, et al. “Hospital Admissions for Asthma in Preschool Children: Relationship to Major Roads in Birmingham, United Kingdom,” *Archives of Environmental Health* 1994; 49(4):223-227.
Gauderman W.J., et al. “Childhood Asthma and Exposure to Traffic and Nitrogen Dioxide,” *Epidemiology* 2005; 16:737-743.
McConnell, R., Berhane K, Yao L, Jerrett M, Lurmann F, Gilliland F, et al. 2006. Traffic, susceptibility, and childhood. *Environ Health Perspect* 2006; 114(5):766-772.
Gauderman WJ et al. Effect of exposure to traffic on lung development from 10 to 18 years of age: a cohort study. *Lancet* 2007; 369(19561): 571-7.
Wilhelm et al.. Environmental Public Health Tracking of Childhood Asthma Using California Health Interview Survey, Traffic, and Outdoor Air Pollution Data. *Environmental Health Perspectives* 2008;116(8):1254-1260.
Meng et al.. Are Frequent Asthma Symptoms Among Low-Income Individuals Related to Heavy Traffic Near Homes, Vulnerabilities, or Both? AEP 2008; 18(5):343-350.

Detailed health assessments of some major California rail yards found extremely high cancer risk from the operations, with elevated cancer risk extending as far as eight miles away.[112] Locomotives may produce about half of all harmful diesel particulate matter emissions in rail yards.[113] Locomotive engines are not only highly polluting, they are incredibly long-lasting, which means many older, high-polluting locomotives are still in operation throughout the U.S.[114] Emissions standards for locomotives lag behind the standards for trucks and even off-road equipment. New Tier 4 standards, comparable to those for modern trucks, will not start

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Venn et al. Living Near A Main Road and the Risk of Wheezing Illness in Children. *American Journal of Respiratory and Critical Care Medicine* 2001; 164:2177-2180.
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[112] California Air Resources Board, Railyard Health Risk Assessments and Mitigation Measures, www.arb.ca.gov/railyard/hra/hra.htm. Cancer risks exceed 1,000 per million next to some of the largest railyards.

[113] “Supplement to the June 2010 Staff Report on Proposed Actions to Further Reduce Diesel Particulate Matter at High-Priority California Railyards.” California Air Resources Board, July 5, 2011. Available at: http://www.arb.ca.gov/railyard/commitments/suppcomceqa070511.pdf, page 2.

[114] EPA, Fact Sheet: EPA Finalizes More Stringent Emissions Standards for Locomotive Engines and Marine Compression-Ignition Engines (PDF) (5 pp, 134K, EPA420-F-08-004, March 2008); available at:
http://www.epa.gov/otaq/regs/nonroad/420f08004.pdf

to be phased in until 2015; these Tier 4 locomotives will emit 80 percent less NOx and 90 percent less PM than a train engine built in 2008.[115] Where Tier 4 locomotives are not yet available, diesel particulate filters (DPFs) and selective catalytic reduction (SCR, a common catalyst based technology used to reduce NOx emissions) can be installed on existing locomotives to achieve emissions reductions similar to those of certified Tier 4s.[116]

Also, 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.[117] 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 by 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,[118] rather than the locomotive engine, to move the cars through the unloading facility.

In addition to electronic positioning systems, mitigations for line haul locomotives should also be included. We recommend tier 4 compliant locomotives or locomotives retrofitted with exhaust controls that can meet tier 4 standards; and a commitment not to idle locomotive engines in the unloading facility, including the use of locomotive idle controls.

II. Public Safety and Noise Impacts

With residential areas just 3,000 feet away from this project (IS/MND at I-2), noise from this project is certain to be a major nuisance. It appears from the project description (IS/MND at I-11 and elsewhere) that the rail activity of four 50-car trains per day would occur predominantly at night. Operations would occur constantly, "24 hours per day/7 days per week/365 days per year." (IS/MND at I-11) Each train crossing Park Road would block that intersection for more than eight minutes for a total of more than half an hour per day of that intersection being blocked (IS/MND at I-11).

While the travel delays caused by lengthy rail crossings may pose a safety concern and a nuisance to the community, our primary concern over health impacts related to the additional rail traffic is in regard to noise. The analysis erroneously dismisses noise from the additional train traffic as "not result[ing] in substantial permanent increases in ambient noise levels," and

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[115] U.S. Environmental Protection Agency. "EPA Finalizes More Stringent Emissions Standards for Locomotives and Marine Compression-Ignition Engines." Regulatory Announcement EPA420-F-08-004, March 2008. Available at: http://www.epa.gov/otaq/regs/nonroad/420f08004.htm.

[116] West Coast Collaborative, Locomotive and Rail Sector meeting materials, 2012, http://westcoastcollaborative.org/wkgrp-loco.htm.

[117] See attached expert report from Dr. Phyllis Fox.

[118] 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).

the project "noise would be similar to noise levels generated by existing refinery operations." (IS/MND at II-53 and II-54) The analysis fails to consider the horns and noise of the four additional trains going through at-grade crossings, particularly at night when most of the activity is expected. Grade separations at major rail crossings should be considered as mitigation.

The IS/MND also fails to adequately address residents' existing noise concerns or to discuss the adverse effects that noise has on people. The IS/MND provides no attempt to gauge existing levels of communication interference, sleep interference or physiological responses and annoyance, nor does it attempt to predict future levels associated with the Project.

The IS/MND also dismisses impacts related to construction noise, on the basis that the nearest residence is 2,700 feet away and thus the project is in compliance with local performance standards (IS/MND at II-53). However, compliance with a certain standard does not necessarily mean noise impacts are insignificant.[119] This is especially true in an area that is already adversely impacted by high noise levels. The IS/MND (at II-52) concedes that worst case noise impacts could be 58 dBA at the nearest residence. In fact, noise from locomotive horns may be much higher and it is not clear that this was considered in the IS/MND. The Federal Rail Administration estimates that railroad horns are in the 95-115 dBA range from 100 feet away and that "the noise resulting from the sounding of train horns has a similar impact to that of low flying aircraft and emergency vehicle sirens."[120]

In any case, noise levels from this project are likely to be above the level that the U.S. Environmental Protection Agency ("EPA") states is significant. EPA holds that a noise impact is significant if it exceeds 55 DNL, identified as the requisite level with an adequate margin of safety for areas with outdoor uses, including residential and recreational uses.[121] However, the IS/MND offers no mitigation for these impacts. Mitigating noise impacts is important not only to address the nuisance aspect of it but also because research on noise from transportation shows significant health impacts.

A. **Communication Interference**

A primary concern in environmental noise problems is communication interference including speech interference and interference with activities such as watching television. Normal conversational speech is in the range of 60 to 65 dBA and any noise in this range or louder may interfere with speech. There are specific methods of describing speech interference as a function of distance between speaker and listener and voice level.

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[119] *See Oro Fino Gold Mining Corporation v. County of El Dorado*, 225 Cal. App. 872, 881-82 (1990).

[120] Federal Rail Administration, Horn Noise FAQ, available at: http://www.fra.dot.gov/Page/P0599

[121] *See* EPA, "Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety" 21 (March, 1974), http://www.nonoise.org/library/levels74/levels74.htm.

B. Sleep Interference

Sleep interference is a major noise concern in noise assessment and is most critical during nighttime hours. Noise can make it difficult to fall asleep, create momentary disturbances of natural sleep patterns by causing shifts from deep to lighter stages and cause awakening. Noise may also cause awakening which a person may or may not be able to recall. Extensive research has been conducted on the effect of noise on sleep disturbance. Recommended values for desired sound levels in residential bedrooms range from 25 to 45 dBA, with 35 to 40 dBA being the norm.

The National Association of Noise Control Officials has published data on the probability of sleep disturbance with various single event noise levels. Based on experimental sleep data as related to noise exposure, a 75 dBA interior noise level event will cause noise induced awakening in 30 percent of the cases.

C. Physiological Responses

These are measurable effects of noise on people such as changes in pulse rate and blood pressure. Generally, physiological responses are a reaction to a loud short term noise such as a rifle shot or a loud jet overflight, or in this case the horn of a train. Noise above 60 decibels ("db") has been shown to have distinct psychological impacts, such as worsening children's mental health, concentration, and classroom behavior in children at school.[122] Other studies show that chronic noise exposure contributes to a worsening of heart disease and higher rates of stroke, after accounting for the risks association with air pollution.[123]

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[122] Matsuoka, M., Hricko, Al, Gottlieb, R., and De Lara, J., Global Trade Impacts: Addressing the Health, Social and Environmental Consequences of Moving International Freight through Our Communities, Occidental College and University of Southern California (Los Angeles, 2011) (hereinafter "Global Trade Impacts"), citing World Health Organization, Guidelines for Community Noise, Chapter 3, Adverse Health Effects of Noise (1999), available at: http://www.who.int/docstore/peh/noise/Comnoise3.htm; van Kempen, E.E., van Kamp, I., Stellato, R.K., et al., "Children's Annoyance Reactions to Aircraft and Road Traffic Noise," J. Accoust. Soc. Am. (2009) 125(2): 895-904; U.S. Department of Transportation, Federal Railroad. Administration, The General Health Effects of Transportation Noise (2002), Document # DTS-34-RR297-LR2 FRS/RDV-03/01; Lercher, P., "Ambient Neighborhood Noise and Children's Mental Health," Occup. Environ. Med. (2002) 59(6): 380-6; Evans, G.W., "Child Development and the Physical Environment," Annual Review of Psychology (2006) 57: 423-51.

[123] Global Trade Impacts, 18, citing Babisch, W., "Transportation Noise and Cardiovascular Risk: Updated Review and Synthesis of Epidemiological Studies Indicate that the Evidence Has Increased," Noise & Health (Jan. 2006), Vol. 8, Iss. 30, 1-29; Sorensen, M., Hvidberg, M., Andersen, Z. J., et al., "Road Traffic Noise and Stroke: A Prospective Cohort Study," Eur. Heart J. (Jan. 25, 2011).

Annoyance is a very individual characteristic which can vary widely from person to person. What one person considers tolerable can be quite unbearable to another of equal hearing capability. The level of annoyance depends on the characteristics of the noise, defined as the loudness, frequency, time and duration of the noise, and how much speech and/or sleep interference results from the noise. The level of annoyance is also a function of the attitude of the receiver. Personal sensitivity to noise varies widely. It has been estimated that 2 to 10 percent of the population is highly susceptible to annoyance from noise not of their own making, while approximately 20 percent is unaffected by noise.

III. General Hazards and Ecological Risks

The IS/MND completely fails to consider or mitigate the potential for rail car accidents or spills. While the IS/MND concedes that crude oil is a hazardous material (IS/MND at II-37), it erroneously concludes that the "quantities of crude delivered by rail and marine vessel offset each other, it is, at a minimum, expected that the relative risks offset each other and that rail transport would present no new significant hazard above the current Refinery baseline risk for marine transport of crude oil to the Refinery." In fact, there is a history of major spills of hazardous materials along California rail routes.[124]

Due to the nature of the very dense and toxic diluted bitumen that the rail cars are likely to carry, as discussed above, these fuels in particular pose an especially serious environmental and public health threat when accidentally released into the environment. EPA recently noted that spills of diluted bitumen require different response action or equipment than for conventional oil spills.[125] Dilbit spills are simply more difficult and more expensive to clean up.[126] In fact, three years after a major spill of dilbit into the Kalamazoo River in Michigan, the heavy oil remains at the bottom of the river requiring dredging and $1 billion clean-up cost.[127] The IS/MND fails entirely to consider the possibility of a dilbit spill into the fragile San Francisco Bay Delta, and what the wildlife, ecosystem, economic and human health implications would be.

It is important to note that human health impacts of bituminous oil spills can be quite serious. We are only beginning to understand the full potential of impacts but spills like the one in Marshall, Michigan give a cautionary sense of how severe impacts can be. There public health officials found numerous acute health impacts lasting for days and spanning numerous areas: Cardiovascular, dermal, gastrointestinal, neurological, ocular, renal, respiratory and other

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[124] For example, there was a very major spill into Upper Sacramento River in 1991. See: http://www.dfg.ca.gov/ospr/NRDA/Cantara.aspx

[125] EPA, Comment letter to US Department of State regarding the Supplemental Draft Environmental Impact Statement from TransCanada's proposed Keystone XL project, 2013.

[126] Environmental Working Group, Poisons in the Pipeline, Tests Find Toxic Stew in Oil Spill, June 2013, page 6.

[127] EPA, 2013

impacts.[128, 129]

IV. Conclusion

The Crude by Rail Project has significant unmitigated effects on the environment. These effects must be analyzed in an Environmental Impact Report and fully mitigated before this Project may lawfully be approved.

Sincerely,

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[128] Michigan Department of Community Health, *Acute Health Impacts of the Enbridge Oil Spill*, November 2010. http://www.michigan.gov/documents/mdch/enbridge_oil_spill_epi_report_with_cover_11_22_10_339101_7.pdf [accessed 19 June 2013]

[129] U.S Department of Health and Human Services and ATSDR, *Kalamazoo River/Enbridge Spill: Evaluation of Crude Oil Release to Talmadge Creek and Kalamazoo River on Residential Drinking Water Wells in Nearby Communities*, 27 February 2013, p. 90. http://www.michigan.gov/documents/mdch/enbridge_oil_spill_epi_report_with_cover_11_22_10_339101_7.pdf [accessed 20 June 2013]