Valero Crude by Rail Project
Public Comments received
March 25 - 31, 2016

Commenter	Date Received
Organizations	
Safe Fuel and Energy Resources California	30-Mar-16
Communities for a Better Environment	30-Mar-16
Individual Comments	
Arlene Van Craeynest	29-Mar-16
Elizabth Lasensky	29-Mar-16
Chihoko and Richard Solomon	29-Mar-16
Diane Bolman	29-Mar-16
Marjorie Xavier	30-Mar-16
Carol Warren	30-Mar-16
Phil Serna,County of Sacramento Supervisor	30-Mar-16
Sara Greenwald	31-Mar-16
Identical Comments	
"Public Comment re Valero Crude by Rail Project - Appeal Application No. 16PLN-00009"	3/25-3/31/16
1062 Commenters (list and sample comment attached)	
Identical Comments - With Modifications	
"Public Comment re Valero Crude by Rail Project - Appeal Application No. 16PLN-00009"	3/25-3/31/16
Elizabeth Fisher	
Jan Summers	
Jan Tache	
David Gates	
Rachel Broadwin	
May O' Brien	
Milton Bosch	
Christine Jones	
Ellen Gachesa	
Sharon Morris	
Mark Garcia	
Matthew Reid	
Linnea Fronce	
Theodora Crawford	
Molly Brown	

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MAR 30 2016
CITY OF BENICIA
COMMUNITY DEVELOPMENT

March 30, 2016

VIA EMAIL AND U.S. MAIL

Mayor Patterson and City Council Members
City of Benicia
250 East L Street
Benicia, CA 94510

Re: March 28, 2016 Letter from Valero to City Council

Dear Honorable Mayor Patterson and City Council Members:

We write on behalf of Safe Fuel and Energy Resources California to respond to Valero's March 28, 2016 letter to the City Council regarding the Valero Crude by Rail Project ("Project"). Valero urges the City to ignore the Project's impacts from crude slate changes. Valero's arguments are unsupported by the facts and the law.

First, Valero's argument that the City should not consider Project impacts from crude slate changes because emissions would not exceed its permit limits has already been rejected by the California Supreme Court. The California Environmental Quality Act ("CEQA")[1] requires the City to determine whether a project would change the existing environment by increasing emissions as compared to actual existing emissions -- not whether the Project will change the environment by exceeding hypothetical emissions allowed under permit limits. This was precisely the issue before the California Supreme Court in *Communities for a Better Environment v. South Coast Air Quality Management District*.[2] The Court rejected the argument that "the analytical baseline for a project employing existing equipment should be the maximum permitted operating capacity of the equipment, even if the equipment is operating below those levels at the time the environmental analysis is begun."[3] The Court held that CEQA requires the baseline to reflect "established levels of a particular use," not the "merely hypothetical conditions

[1] Pub. Resources Code § 21000, et seq.
[2] *Communities for a Better Environment v. South Coast Air Quality Management District* (2010) 48 Cal.4th 310.
[3] *Id.* at 316.

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allowable under the permits..."[4] Following the Supreme Court decision, the court in *Communities for a Better Environment v. City of Richmond*[5] similarly rejected the city's use of a hypothetical baseline, which failed to reflect actual operational conditions. "The [Supreme Court] stated that using hypothetical, allowable conditions as a baseline 'will not inform decision makers and the public of the project's significant environmental impacts, as CEQA mandates.'"[6] Thus, Valero's argument has already been rejected by the California Supreme Court.

Second, Valero's argument that the City shouldn't be concerned with crude slate changes, because the "crude must be blended to within the very same operational parameters" currently processed at the refinery, blatantly ignores higher toxic air contaminants ("TAC"), malodorous compounds, vapor pressure and flammability. Valero measures its operational parameters by the weight and sulfur content of crude.[7] Even if crude is blended to the current range of weight and sulfur content, other components in the crude, such as TACs (e.g., benzene), or highly malodorous compounds (e.g., mercaptans), may be present at much higher concentrations than in the crudes they replace.[8] Vapor pressure and flammability may also differ significantly between existing and replacement crudes.[9] The City's own consultant pointed out that there is no relationship between vapor pressure and crude weight.[10] This distinction is important because "vapor pressure of crude determines to a large extent the amount of [reactive organic gases] ("ROG") and TAC emissions" from transport, storage and refining of crude.[11] "Thus, a crude slate may have identical sulfur content and weight, but would result in dramatically different ROG and TAC emissions."[12] Notably, Bakken crudes "have uniquely elevated vapor pressures compared to the light sweet crudes they would replace."[13] In addition, "the nature of the chemical bonds in crude determines the amount of energy and hydrogen that must be supplied to refine it."[14] Therefore, even if a new crude slate is blended to the identical sulfur content and weight as the

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[4] *Id.* at 322.
[5] *Communities for a Better Environment v. City of Richmond* (2010) 184 Cal.App.4th 70.
[6] *Id.* at 89.
[7] DEIR, Appendix C.1, p. 1-3.
[8] Phyllis Fox Comments on DEIR, September 15, 2014, p. 4.
[9] *Id.*
[10] DEIR, p. K-18.
[11] Phyllis Fox Comments on DEIR, September 15, 2014, pp. 5, 11-12.
[12] *Id.*
[13] *Id.* at pp. 13-14.
[14] *Id.* at p. 5.

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existing slate, it will have chemical and physical differences that would result in increased emissions and significant on-site air quality impacts.[15] Indeed, the Bay Area Air Quality Management District ("BAAQMD") urged the City to "evaluate potential changes in emissions associated with handling the new crude as a result of this project."[16] According to the BAAQMD, "[l]ighter crude generally has a higher content of volatile organic compounds which can result in increased fugitive emissions during transport and storage in comparison to the current crude."[17]

CEQA requires the City to determine whether the Project would change the existing environment, regardless of Valero's existing permits. Further, substantial evidence shows that blending new crudes does not address the fact that the crude slate changes would result in significant, on-site air quality and public health impacts. Therefore, the City Council must reject Valero's arguments to the contrary.

Thank you for your consideration and attention to this important matter.

Sincerely,

Rachael E. Koss

REK:ric
cc: Donald Dean, Chair, Planning Commission (via email)
Amy Million, Principal Planner (via email)

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[15] *Id.*
[16] Letter from the BAAQMD to Amy Million re: Valero Crude by Rail Project Draft Environmental Impact Report, September 15, 2014, p. 3.
[17] *Id.*

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Expert Report of Greg Karras
Communities for a Better Environment (CBE)
30 March 2016

RECEIVED
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CITY OF BENICIA
COMMUNITY DEVELOPMENT

Regarding the
Appeal of Planning Commission Actions on the Valero Benicia Crude by Rail Project and **Environmental Impact Report (EIR)**
City of Benicia, California
State Clearinghouse #2013052074
Use Permit App. 12PLN–00063

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

4. I have served as an expert for CBE and other groups participating in environmental impact reviews of related refinery projects, including, among others, the "Contra Costa Pipeline Project," the "Phillips 66 Propane Recovery Project," the "Shell Greenhouse Gas Reduction Project," the "Chevron Richmond Refinery Modernization Project" and the "WesPac Pittsburg Energy Infrastructure Project" in the County of Contra Costa, and the "Phillips 66 Company Rail Spur Extension Project" now pending before the County of San Luis Obispo. My work as an expert for CBE and other non-profit groups in a 2007–2008 review of the proposed Chevron Richmond refinery "Hydrogen Renewal Project" was cited by the Appeals Court in support of CBE's subsequent successful advocacy regarding that proposed project (*See CBE v. City of Richmond* 184 Cal_Ap.4th).

5. During 2014 I served as an expert for the Natural Resources Defense Council in research on the effects of changes in oil feedstock quality on refinery air emission rates, specifically, on estimating toxic and particulate emissions from U.S. refinery cracking and coking of low quality, bitumen-derived "tar sands" oils.

6. As part of CBE's collaboration with the refinery workers union United Steelworkers (USW), community-based organizations, the Labor Occupational Health Program at UC Berkeley, and environmental groups, I serve as an expert on environmental health and safety concerns shared by refinery workers and residents regionally. In this role I serve as CBE's representative in the Refinery Action Collaborative of Northern California, and as an expert for CBE and other groups in the development of refinery emission control rules to be considered for adoption by the Bay Area Air Quality Management District.

7. I serve as one of CBE's experts supporting informal state-level climate and energy planning discussions with California State agencies and the Office of Governor Edmund G. Brown. In this capacity I participated in meetings organized and attended by

Governor Brown's senior advisors on 12 July 2013 in Oakland, California, and 13 April 2015 in Sacramento, California.

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

9. My more recent publications include the first peer reviewed estimate of combustion emissions from refining lower quality crude oils to be based upon data from U.S. refineries in actual operation, which was published by the American Chemical Society in the journal *Environmental Science & Technology* in 2010. I authored a follow up to this national 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. I authored and presented invited testimony regarding *inherently safer systems* requirements for existing refineries that change crude feedstock at the U.S. Chemical Safety Board's 19 April 2013 public hearing on the Chevron Richmond refinery fire. I authored a research report, published in January 2015, on the results of work I conducted for the Natural Resources Defense Council on estimating toxic and particulate emissions from U.S. refinery cracking and coking of bitumen-derived "tar sands" oils.

10. My curriculum vitae and list of publications were provided to the City of Benicia with my previous comment in this matter. Please see the "Supplemental Technical Comments of Communities for a Better Environment regarding the Valero Benicia Crude by Rail Project ('project')" dated 15 September 2014, which I authored, for this information.

Scope of Review

11. I have reviewed the project called the Valero Benicia Crude by Rail Project ("project") and the project's Environmental Impact Report ("EIR"), including the draft EIR ("DEIR"), revised draft EIR ("RDEIR") and final EIR ("FEIR") documents, and have previously provided expert comment in this matter.[1] I reassert my previous comments as they remain relevant and were not addressed in the EIR. The Planning Commission decided not to approve the land use permit for the project and decided not to certify the EIR on 11 February 2016. Valero Refining Company ("Valero") appealed these Planning Commission decisions to the City Council on 29 February 2016. (*See* the "Appeal of Planning Commission Resolution No. 16–1, Denying Use Permit Application 12PLN-00063 and Declining to Certify Final Environmental Impact Report for the Valero Benicia Crude-by-Rail Project [SCH #2013052074]"; letter from John J. Flynn III, Nossaman LLP to Lisa Wolfe dated 29 February 2016 [hereinafter "29 Feb letter"].)

12. Valero's appeal asserts conclusions regarding factual issues that were addressed by my previous comments. It asserts that: "All of the public discussion about the Project has focused on the impacts of rail operations." (29 Feb letter at ¶ 1.A.) Then it asserts the project will not result in any change to refinery emissions. (29 Feb letter at ¶ 1.D.) Then Valero asserts that "the only significant unmitigated Project-related environmental impacts result from rail operations." (29 Feb letter at ¶ 3.D.) Valero then concludes that "environmental review of Valero's Project has been exhaustive." (29 Feb letter at ¶ 4.) As to that assertion (Id.), among other things, Valero specifically disputes the Planning Commission's findings that the EIR failed to disclose and evaluate project changes in the refinery's crude slate, air quality impacts, and climate impacts sufficiently. (29 Feb letter at ¶ 3.D parts 9, 13.b, 13.c, and 14.)

13. My review of the project, EIR, and Valero appeal reported herein is focused on the assertions made by Valero in its appeal to the City Council that are identified in the paragraph directly above. My opinions on these matters and the basis for these opinions are stated in this report.

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[1] *See* the "Supplemental Technical Comments of Communities for a Better Environment (CBE) regarding the Valero Benicia Crude by Rail Project ('project') Draft Environmental Impact Report ('DEIR'), Use Permit App. 12PLN-00063, SCH #2013052074, by Greg Karras, Senior Scientist, 15 September 2014."

The Appeal Misrepresents the Project Review

14. The assertion that "[a]ll public discussion about the Project has focused on the impacts of rail operations"[2] is inaccurate and misleading. Goodman and Rowan (2013) showed that the project could change the refinery's crude slate.[3] Fox (2013) showed this could cause significant impacts from refining operations.[4] By 1 July 2013 at least eleven groups, including CBE and the refinery workers union United Steelworkers (Local 675), sought full disclosure and analysis of the changes in refinery oil feedstock and emissions that could result from the project.[5] The EIR identified this potential for project-driven changes in its crude slate to cause impacts in the refinery as an "area of controversy."[6] Fox (2014),[7] Pless (2014),[8] Karras (2014),[9] Fox (2016),[10] Pless (2016)[11] and others[12] commented in detail on the EIR's failure to evaluate these and other refining impacts of the proposed project. Valero is on record acknowledging this focus of independent public comment on refining impacts of the project, as shown by the company's attempt, at the Planning Commission's Public Hearing, to rebut comments regarding these refinery impacts of the project,[13] in direct contradiction to its position on appeal.

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[2] This is quoted from paragraph 1.A of Valero's appeal document (29 Feb letter as cited above).
[3] http://www.ci.benicia.ca.us/index.asp?SEC=B7EDC93A-FFF0-4A14-9B1A-1C8563BC256A&Type=B_BASIC ("City Web Site"); Supplemental Documents for NRDC Comment on IS/MND; Goodman Group Report.
[4] City Web Site; Supplemental Documents for NRDC Comment on IS/MND; Report by Dr. Fox.
[5] City Web Site; Initial Study/Mitigated Negative Declaration; Public Comments Received May 30–July 1, 2013; Comment B3.
[6] DEIR at ES-7, 1-4, Appendices C.1 and C.2; FEIR at 4-13 through 4-18.
[7] City Web Site; SAFER California Comments on DEIR Attachment A.
[8] City Web Site; SAFER California Comments on DEIR Attachment C.
[9] City Web Site; CBE Karras Comments on DEIR.
[10] City Web Site; Additional Public Comments; January 29–February 8, 2016; 8 Feb 2016 comments of Dr. Fox (Attachment C to SAFER California Comments).
[11] City Web Site; Additional Public Comments; January 29–February 8, 2016; 8 Feb 2016 comments of Dr. Pless (Attachment D to SAFER California Comments).
[12] Many other comments provided evidence of the potential for these impacts and the failure of the EIR to address them: *see* e.g., 2 Oct 2014 comments of Attorney General Harris; and the 8 Feb 2016 comments of the Natural Resources Defense Council, Benicians for a Safe and Healthy Community, CBE, ForestEthics, and 16 other groups (City Web Site; Additional Public Comments; September 16–October 16, 2014; and January 29–February 8, 2016).
[13] City Web Site; Planning Commission Minutes, Presentation & Miscellaneous Information; Planning Commission February 9, 2016 Full Transcript; pp. 27–51 (*see esp.* page 27, lines 10–15; page 34 line 12 through page 35 line 4; and page 49 line 12 through page 51 line 4).

15. Comments on the EIR link the project's crude switch to many refinery impacts. Contaminants that are more concentrated in the new crude slate could pass through the refinery in greater amounts: for example, high-selenium crude can cause a refinery's releases of this toxic element to increase by a factor of up to ten times.[14] Refining properties of the new crude slate could require more intensive processing that increases refinery emissions: for example, peer reviewed work shows the potential for crude feed quality to drive processing changes that require burning 2–3 times more fuel energy per barrel of crude refined.[15] This more severe (intensive) processing environment also could increase the frequency and magnitude of hazardous incidents: for example, worsening oil quality worsened equipment corrosion that contributed to fatal fire and catastrophic air pollution incidents at Bay Area refineries.[16] Additional examples of refinery hazard and emission impacts from the placement and operation of new, existing and expanded refinery facilities that enable the feedstock switch are discussed below.

16. In fact, changing refinery feedstock is the sine qua non[17] of the project. The basic function of the project as proposed requires refining the oil to be received.[18] Because the Benicia plant already runs near capacity, refining crude received via its pipeline and wharf, the project thus requires replacing current refinery feedstock.[19] But the Alaskan, Californian, and globally sea-tankered crude streams the refinery receives by pipeline and ship cannot be accessed economically by rail, and the tar sands and fracked shale oils that project oil trains would access from the U.S. Great Plains and Alberta, Canada cannot be accessed economically at project volume by pipeline or ship.[20] Therefore, the project would both enable and <u>require</u> the refinery to change its crude slate.

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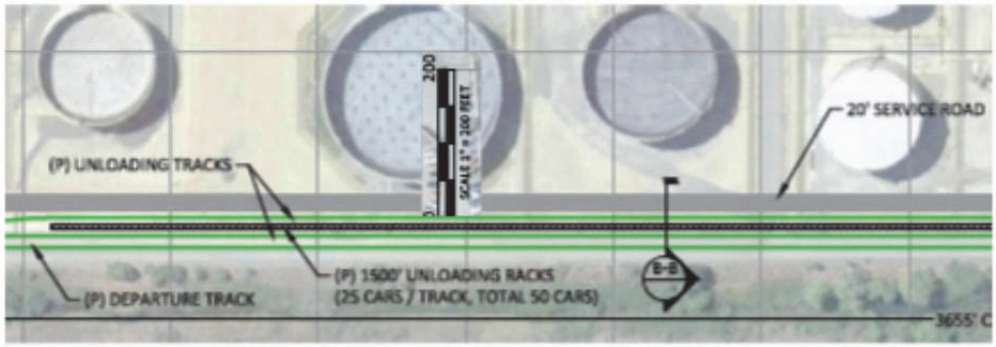
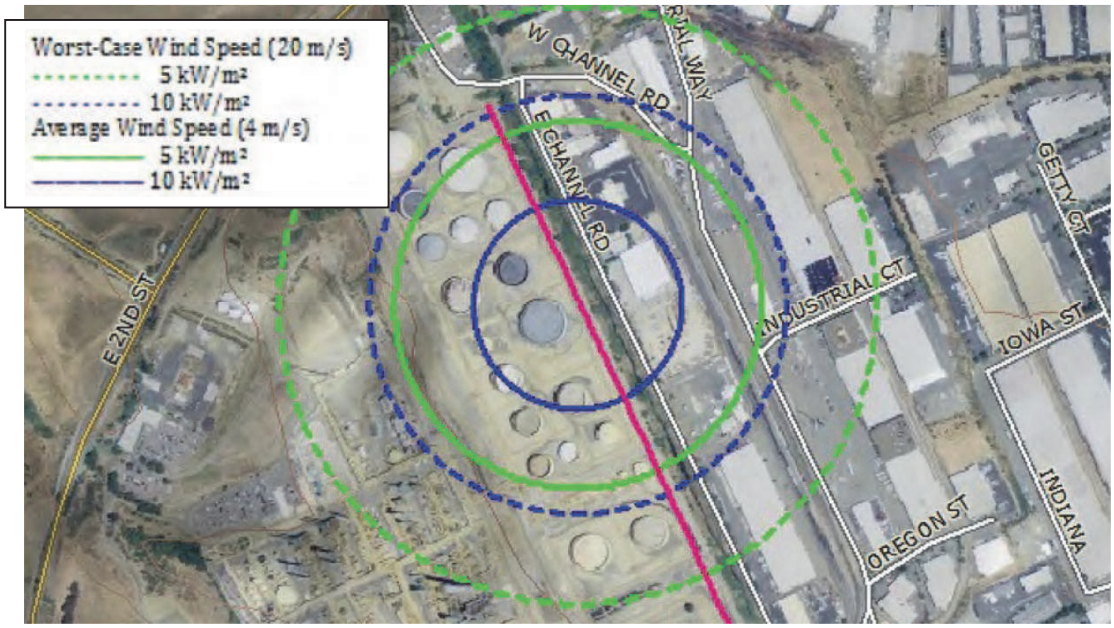
[14] *See* CBE Report 94-1, incorporated by reference in previous comment (Karras, 2014 at 15).
[15] *See* attachments KR 2–4, incorporated by reference in prior comment (Karras, 2014 at 17).
[16] *See* U.S. CSB, 2001; and CSB, 2013 (Attachment KR-5), incorporated in Karras, 2014 at 17.
[17] The essential element, without which it cannot come into existence as proposed.
[18] Valero does not propose exporting this crude and the EIR asserts Benicia will refine all of it.
[19] Valero asserts barrel-for-barrel replacement of current crude input; the EIR asserts crude slate volume will not change (*see* RDEIR at 2-6); and data in permit orders it cites (Att. KR-7) indicate that at least 55,000 b/d of the crude slate must be displaced at the 70,000 b/d project capacity.
[20] West Coast access to these landlocked high plains and Alberta oils via pipeline and ship is severely bottlenecked (Goodman and Rowan, 2013; Fox, 2013), as Valero's objective to "[a]llow for the delivery of up to 70,000 barrels per day of North American-sourced crude oil" (RDEIR at 2-2) implies. From 2010-2012 it proved able to get an average of only 2,210 b/d of Canadian tar sands "dilbit" crude (*see* Table 4 in Karras, 2014; 19–24 ºAPI, 3.5–3.9% sulfur), only 3.1% of its 70,000 b/d objective. Fox (2016), showing that rail-to-pipeline access for these landlocked and bottlenecked crude streams is an alternative version of the project, further proves the point.

The Appeal Ignores Refinery Hazard Impacts

17. An excerpt from the DEIR showing that the new facilities would be very close to existing storage tanks on the refinery site that was presented in my previous comments, and a project oil fire hazard radius map of the same post-project onsite area from the RDEIR, are excerpted below. This evidence indicates a new catastrophic hazard from "knock-on" effects (e.g., project oil fires could catch nearby refinery tanks on fire).



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



Map 2. Excerpt from RDEIR Figure 4.7-8. "Worst-Case Facility Thermal Radiation Hazards." Existing refinery storage tanks within the inner hazard circle (10 kW/m^2 at 4 m/s wind speed) are those shown in the center of Map 1 above. Proposed unloading facilities are represented by the diagonal pink line in this map and by the horizontal green and black lines in Map 1.

A hydrocarbon tank fire that could result from this hazard, should it manifest, could cause catastrophic and irreversible impacts. This new knock-on impacts hazard would be caused by Valero's proposal to place and to operate new crude oil unloading facilities dangerously close to existing facilities within the refinery.

18. This evidence also reveals clear and significant errors in the EIR. Instead of responding to my previous comment that this knock-on hazard was not identified, evaluated, or addressed by the DEIR, the FEIR refers to a quantitative risk analysis in the RDEIR,[21] but that referenced analysis (RDEIR at 2-106 to 2-108; RDEIR Appendix F) does not include any analysis of this knock-on hazard. The EIR thus fails to respond to comment, and fails to identify or address a significant potential hazard impact of the project. Valero ignores this evidence that directly contradicts its position on appeal.

The Appeal Obscures Refinery Emission Impacts

19. Comments on the EIR provide abundant evidence for significant impacts from increased refinery emissions of toxic, criteria, and climate-disrupting air pollutants that would be caused by project changes in properties of the refinery crude slate that are not disclosed, evaluated, or addressed in the EIR or by Valero's appeal.[22] An example of this evidence that was summarized in my testimony before the Planning Commission is presented in Table KR-1 and the discussion below.

20. Refining hydrogen-rich engine fuels from hydrogen-poor tar sands oils requires adding hydrogen to the oils during processing, and the intentional production of this hydrogen in fossil fuel-fed steam reforming plants is a major greenhouse gas (GHG) emitter in refineries.[23] Hydrogen is the most abundant atom in crude, and at 1/12th the mass of carbon, small differences in hydrogen wt. % represent larger differences in H_2 deficiency among crude oils. The 1.0–1.9 lb/b H_2 deficiency of project tar sands blends as compared with the Alaskan crude and Brazilian/Iraqi blend in Table KR-1 represents an additional 70,000–133,000 lb/d of H_2 production to refine post-project crude slates that replace 70,000 b/d of these current crude feeds with project tar sands blends.

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[21] FEIR Response to Comments at comment B9-39.
[22] Goodman and Rowan (2013); Fox (2013); CBE et al. (2013); Fox (2014); Pless (2014); Karras (2014); Harris (2014); NRDC et al. (2016); Fox (2016), and Pless (2016). (Footnotes 3–5; 7–12.)
[23] *See* attachments KR-1 through KR-4 appended hereto. These documents were incorporated by reference in previous comments and are re-supplied herein for the City Council's convenience.

Table KR-1. Potential CO_2 emissions increment from Benicia Refinery hydrogen production to process hydrogen-deficient tar sands oils enabled by the project.

Crude oil data[a]	Density		Sulfur content		Hydrogen content	
	(°API)	(lb/bbl)	(wt. %)	(lb/bbl)	(wt. %)	(lb/bbl)
Baseline crude oils/blends						
Alaska North Slope (ANS)	31.4	304	0.85	2.59	12.8	39.0
Brazil Lula (BL)	29.3	308	0.27	0.83	12.7	39.3
Iraq Basra (IB)	30.2	306	2.66	8.15	12.5	38.4
50% BL / 50% IB blend	30.0	307	1.46	4.49	12.6	38.8
Tar sands dilbit oils						
Cold Lake (CL)	20.7	325	3.89	12.7	11.2	36.4
Seal Heavy (SH)	20.6	326	5.14	16.7	10.6	34.5
W. Canadian Select (WCS)	20.5	326	3.38	11.0	11.2	36.5
Tar sands SCO oils						
Husky Synthetic Blend (HSB)	32.6	302	0.09	0.27	12.9	38.8
Suncor Synthetic A (OSA)	33.1	301	0.16	0.48	12.7	38.2
Syncrude Synthetic Bld (SSB)	31.5	304	0.14	0.42	12.5	38.1
Tar sands rail import blends						
50% WCS / 50% OSA blend	26.7	313	1.84	5.75	11.9	37.4
45% CL / 55% HSB blend	27.2	312	1.87	5.85	12.1	37.8
30% SH / 70% SSB blend	28.3	310	1.71	5.32	11.9	37.1

	Crude slate change (hydrogen deficiency) from:	
	replacing ANS with WCS/OSA blend (lb H_2/bbl)	–1.60
	replacing BL/IB with CL/HSB blend (lb H_2/bbl)	–1.00
	replacing ANS with SH/SSB blend (lb H_2/bbl)	–1.90
CO_2 emission factor[b]	H_2 steam reforming emissions (kg CO_2/lb H_2 produced)	4.68

Emissions increase from H_2 production to offset the decreased H_2 content of the post-project crude slate	CO_2 emission increment from:	kg/bbl	MTY @ 70 kbpd
	replacing ANS with WCS/OSA	+ 7.49	+ 191,000
	replacing BL/IB with CL/HSB	+ 4.68	+ 120,000
	replacing ANS with SH/SSB	+ 8.89	+ 227,000

CO_2 emissions from refinery hydrogen production could increase by ≈ 120,000–227,000 metric tons per year to make up the hydrogen deficiency from replacing 70,000 barrels per day of the current Benicia refinery crude slate with tar sands oil imports, a likely result of Valero's proposed project. **MTY:** metric tons per year. **kbpd:** thousand barrels per day. **Dilbit:** blend of diluent oil and bitumen to enable transport of the crude oil. **SCO:** synthetic crude oil; bitumen that is partially upgraded before refining. **(a)** Crude oil data are from Abella and Bergerson (*see* also www.ucalgary.ca/lcaost/prelim) and are given in Attachment KR-4. Blends within the refinery's 20–36 °API and 0.4–1.9 % sulfur crude slate envelope the EIR reports were calculated from mass/barrel data. For example, the 50% BL / 50% IB blend was calculated from the Brazil Lula (BL) and Iraq Basra (IB) data as follows: 0.5 x 308 + 0.5 x 306 = 307 lb/bbl (30.0 °API); 0.5 x 0.83 + 0.5 x 8.15 = 4.49 lb/bbl sulfur (1.46 wt. % of the 307 lb bbl); and 0.5 x 39.3 + 0.5 x 38.4 = 38.8 lb/bbl hydrogen. In addition to the Alaska North Slope crude (ANS) it was designed for, the Benicia refinery runs significant amounts of crude from Brazil and Iraq with the density and sulfur content of Lula, and Basra, respectively. *See* Karras (2014) Table 4. Tar sands oils shown span the range of density, sulfur, and hydrogen in Canadian bitumen-derived oils that the project allows the refinery to run in much larger volume. **(b)** Refiners must add hydrogen to H_2-deficient crude oils such as bitumen to make H_2-rich engine fuels, and refiners produce the additional H_2 by steam reforming, a major CO_2 emitter in refineries. (Atts. KR 1–4.) The refinery has begun to expand its H_2 production capacity. (*See* Att. KR-7.) The emission factor of 4.68 kg CO_2 per pound of H_2 production is a conservative estimate from the peer reviewed literature. (Att. KR-2 Table S1 [16.4 MJ/m^3 H_2 and 52.7 kg CO_2/GJ in steam reforming], and USDOE H_2 conversion [5.42 m^3 per lb. H_2]).

21. Crude density, sulfur, and H_2 data shown in the table were reported by a peer-reviewed study in previous comment. (Att. KR-4.) The project could replace 70,000 b/d of the current crude slate—including Alaskan North Slope crude (ANS; Att. KR-2), and oils from Brazil and Iraq with API Gravity and sulfur content matching the Brazil-Lula and Iraq-Basra oils in Table KR-1[24]—with the tar sands oil blends shown in the table.[25] Individual current (Lula, Basra) and project (dilbit and SCO) crude oils fall outside the crude slate envelope reported in the EIR for sulfur, but all the blends of these oils shown in the table are within the 20–36 ºAPI and 0.4–1.9% sulfur crude slate envelope it reports. The project enables this switch to crude with a 1.0–1.9 pounds per barrel H_2 deficiency.

22. Producing each pound of this extra hydrogen would emit ≈ 4.68 kilograms of carbon dioxide (CO_2) from hydrogen steam reforming. This is a conservative estimate from my peer-reviewed work.[26] The steam reforming process runs at extremely high temperature and pressure, requires a large fuel energy input, and co-produces H_2 and CO_2 from its hydrocarbon feed as major reaction products. At 4.68 kg CO_2/lb H_2, making up the 1.0–1.9 lb/b H_2 deficiency shown in the table would emit ≈ 4.68–8.89 kilograms more CO_2 for each barrel of ANS, 50% Lula / 50% Basra blend—or other oils in the current crude slate with similar hydrogen content—that the project enables Valero to replace with the tar sands rail import blends in Table KR-1.

23. This evidence indicates that, at the project potential to replace 70,000 b/d of current crude feed with tar sands bitumen-derived oils, hydrogen production to make up the hydrogen deficiency of the new crude oil slate enabled by the project could increase refinery CO_2 emissions by ≈ 120,000–227,000 metric tons/year.[27] This refinery emission increment exceeds the EIR's significance threshold (10,000 MTY) by 11–22 times.

24. As stated (¶ 19), the EIR does not disclose, evaluate, or mitigate any of the significant refinery emission impacts documented by comments. The EIR does not even disclose the changes in refinery crude slate quality that would be enabled by the project and would drive these impacts. (*See* Karras, 2014; Fox, 2016; and atts. KR 1–6.) Both

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[24] Compare Table 4 in Karras (2014) to the BL and IB crude data shown in Table KR-1 herein.
[25] Tar sands oil is the likely rail import: Goodman and Rowan (2013); Fox (2013); Karras (2014).
[26] Attachment KR-2 at Table S1 (16.4 MJ/m^3 H_2 product and 52.7 kg CO_2/GJ in steam reforming) and 16.4/1,000 x 52.7 = 0.864 kg/m^3 H_2; or 0.864 x 5.42 m^3/lb H_2 = 4.68 kg CO_2/lb H_2 produced. The 5.42 m^3/lb H_2 value is from the U.S. Department of Energy hydrogen conversion calculator.
[27] Low end from 4.68 kg/b crude x 70,000 b/d x 365 d/y ÷ 1,000 kg/ton = 119,574 metric tons/y; high end from 8.89 kg/b crude x 70,000 b/d x 365 d/y ÷ 1,000 kg/ton = 227,140 metric tons/y.

Valero and the EIR argue against these disclosures, arguing that the crude oil data are confidential and that there is no need for further disclosure. Specifically, they assert that any feedstock-driven impacts in the refinery would be correlated with the API Gravity (density) and sulfur content of its crude slate, and would remain within such a narrow refinery operating envelope ("range") of oil density, oil sulfur, and process capacity limits that no such impacts could occur.[28] These assertions are clearly erroneous.

25. Karras (2010) showed that density and sulfur alone did not predict anomalously high hydrogen requirements that were documented at Rocky Mountain States refineries running crude slates including tar sands oils. (Att. KR-2.) Abella and Bergerson (2012) showed that accurate prediction of crude slate impacts on a refinery's processing and emissions requires evaluation of other crude oil properties besides density and sulfur, such as distillation properties and hydrogen content. (Att. KR-4.) Fox (2016) showed that many other properties of the crude slate that could cause significant impacts in the refinery do not correlate with its density and sulfur content. In fact, refiners routinely model new crude slates based on many other properties including detailed distillation properties and hydrogen content. (*See* Atts. KR-3, KR-4.) Valero's insistence on the fallacy that density and sulfur content correlate with and predict all potential impacts of its crude slate on its refinery's processing appears disingenuous: it could not operate its refineries efficiently if it actually put this fallacy into practice.

26. Valero's assertion that the "narrow" range of its crude slate operating envelope will prevent refining impacts is similarly inaccurate and misleading. The significant H_2 impacts discussed above would occur within this envelope. (¶ 21.) Increased crude slate sulfur content that stayed within the Richmond refinery's operating envelope greatly worsened corrosion of the pipe that failed catastrophically in the August 2012 fire that sent some 15,000 people to area hospitals. (Att. KR-5.) Moreover, the alleged range is not so "narrow" as Valero asserts: actual operating data from U.S. refineries predict that a U.S. crude slate change of much less than this 20–36 ºAPI and 0.4–1.9% sulfur range, from 33.0 to 26.5 ºAPI and 0.93 to 1.21 wt. % sulfur, could cause the average U.S. refinery's CO_2 emissions to increase by ≈ 30%, from ≈ 270–350 kg/m^3 crude refined.[29]

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[28] *See* Valero Data Response #1 at pp. 1–2; Valero appeal (29 Feb letter) at ¶¶ 1.D, 3.D, and 4; DEIR at 3-22 through 3-24; RDEIR at 2-6, 2-23; FEIR Response to Comments at comments A20-1, B9-63 through B9-78, and J3-4; and FEIR at 4-13 through 4-18.

[29] Attachment KR-2; *esp.* Table S8, PADDs 1 and 5, 2000 (33.0–26.5 ºAPI, 0.93–1.21% sulfur). Note: ºAPI = (141.5 ÷ SG)–131.5, where SG (specific gravity) = crude density in kg/m^3 ÷ 1,000.

As Harris (2014)[12] and others correctly commented on this same error in the EIR, the project could cause impacts by changing the proportion of low quality crude in the refinery's slate, whether or not it stays within the asserted operating envelope range.

27. Valero's assertion that its current refinery capacity and permit limits prevent any change in its crude slate, processing, or emissions also is inaccurate and misleading. Based on the data in Attachment KR-7,[30] the refinery's permitted capacity allows it to increase its crude feed rate by ≈ 18 % (from 140,000–165,000 b/d), its catalytic cracking feed rate by ≈ 10 %, its coking rate by ≈ 35 %, and its hydrocracking rate by ≈ 23 %. Further, its air permit allows hydrogen production to increase by at least 16 % (+26 MMSCFD), upon commissioning of its concurrent hydrogen plant expansion.[31] The EIR admitted Valero was concurrently considering this hydrogen expansion (DEIR at 3-12), but then committed the same clear error as Valero's appeal: asserting permit conditions that <u>allow</u> changes in processing will prevent changes in processing. The increase in maximum permitted hydrogen production upon completing Valero's concurrent plant expansion (+26 MMSCFD) represents ≈ 50,500,000 lb/y of additional H_2 production,[32] which could emit ≈ 236,000 metric tons/y of CO_2,[33] consistent with the emission increment that could be driven by the project's crude switch.

28. The crude density, sulfur, and hydrogen data presented in Table KR-1 are public data. (Att. KR-4.) This also is true of the refinery-specific crude source and crude slate density and sulfur content data in Table S9 of Attachment KR-2; the refinery-specific imported crude source, density, and sulfur data in Table 4 of Karras (2014); the detailed ANS assay data in Table 5 of Karras (2014); and the refinery-specific crude slate density, sulfur, cadmium, mercury, nickel, selenium, vanadium, and distillation data reported in Attachment KR-6. Public data are not secret. Thus, the assertion that the EIR properly omitted disclosure and evaluation of these data as confidential information is false. The Attorney General's comment that the EIR is deficient because of this nondisclosure that results from its "overly broad determination of trade secrets" (Harris, 2014)[12] is correct.

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[30] Excerpts from permit orders issued to the refinery by the Air Quality Management District and the Regional Water Quality Control Board that were cited and relied upon by the EIR; *<u>compare</u>* limits for S#s 1006, 5, 6, and 1003 in Table II A with process-specific throughputs in Table F-1E.
[31] Attachment KR-7 at Table II A, sources S-1010 and S-1062.
[32] Based on 365 days/y 26,000,000 SCF/d ÷ 188 SCF/lb H_2 = 50,478,723 lb H_2/year.
[33] Based on 50,500,000 lb H_2/y x 4.68 kg CO_2/lb H_2 x 1/1,000 tons/kg = 236,340 metric tons/y CO_2 emission. The emission factor (4.68 kg CO_2/lb H_2) is from Att. KR-2 as described in ¶ 22.

By relying on a false assertion of confidentiality to withhold disclosure and evaluation of the changes in crude slate properties that would result from the project and would affect refinery processing and emissions, Valero's appeal—and its EIR—obscure significant potential refining impacts of the project.

29. A U.S. Energy Information Administration report that identifies the Benicia refinery as exporting refined engine fuels product overseas is appended hereto as Attachment KR-8.[34] This evidence is relevant because Valero asserts its project will reduce emissions by reducing ship traffic, but it has not disclosed or accounted for growing exports, which move by ship. Valero's assertion is unsupported. Even if the project replaces crude that is delivered by ship rather than by pipeline,[35] Valero would likely use the wharf capacity this frees up to increase its product exports, in order to offset the trend of California gasoline demand decline—a trend which has continued over the past decade, and would continue under state climate policy. It also would avoid any obligation to comply with the state's Low Carbon Fuel Standard, for the refined fuels its refinery exports. Valero's unsupported claim that reduced ship traffic emissions will offset project emissions further obscures refinery-related impacts of its project.

30. Comments to the Bay Area Air Quality Management District on the ongoing development of a proposed petroleum refining emission limits and risk thresholds rule, Regulation 12, Rule 16, that were submitted by Valero in September 2015 are appended hereto as Attachment KR-9. Valero opposes this proposal "to cap refinery emissions" (prevent them from increasing), arguing, among other things, that its Benicia refinery "will be significantly impacted" because it needs the "operational flexibility" to increase emissions up to its maximum currently permitted potential to emit. (Att. KR-9 at 1–3.) The company's position in this concurrent regional policy proceeding—that it will be "significantly impacted" unless its refinery emissions are allowed to increase—stands in contradiction the position it has taken before the City Council on appeal, that there will be "no change to refinery emissions."[36]

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[34] Following questions about possible current or future exports from the refinery that were asked by the Planning Commission during its hearing on the project, this document (Att. KR-8) was presented during the Planning Commission hearing for the record.

[35] Available evidence suggests that crude delivered by rail as a result of the project is at least equally likely, and is probably more likely, to replace crude deliveries by pipeline than to replace crude deliveries by marine transport over the Benicia refinery's wharf (Karras, 2014).

[36] *Compare* Attachment KR-9 at pp. 1–3 with Valero's appeal (29 Feb letter) at ¶ 1.D.

Opinion

31. Changing refinery feedstock is the essential element of the proposed project. The switch to a lower quality, higher tar sands oil-content crude slate that is enabled by the project, and the operation of project oil delivery facilities onsite very close to existing refinery facilities, would likely result in significant refinery emission and hazard impacts. Instead of disclosing and addressing these impacts the EIR obscures them. The EIR claims to evaluate a hazard it did not evaluate, fails to disclose crude slate quality impacts of the project, and argues against this disclosure based on assertions that are clearly false. It asserts that public data are secret, that non-correlated crude slate impacts are correlated, that significant ranges in these impacts are insignificant, and that capacity limits allowing these impacts will prevent them. Valero's appeal misrepresents the project review and perpetuates this nondisclosure based on these same clearly false assertions while omitting evidence that its own export and policy activities suggest increasing refinery emissions. Valero thereby further obscures the refinery impacts of its project.

32. 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 30th day of March 2016 at Richmond, California

Greg Karras

Attachments List

Attachment KR-1. Meyer et al., 2007. *Heavy Oil and Natural Bitumen Resources in Geological Basins of the World;* U.S. Geological Survey Open-File Report 2007–1084.

Attachment KR-2. Karras, 2010. Combustion Emissions from Refining Lower Quality Oil: What Is the Global Warming Potential? *Environmental Science & Technology* **44**(24): 9584–9589. DOI: 10.1021/es1019965. Includes Supplemental Information (SI).

Attachment KR-3. Bredeson et al., 2010. Factors Driving Refinery CO_2 Intensity, with Allocation into Products. *International Journal of Life Cycle Assessment* **15:** 817–826.

Attachment KR-4. Abella and Bergerson, 2012. Model to Investigate Energy and Greenhouse Gas Emissions Implications of Refining Petroleum. *Environmental Science & Technology*. **46:** 13037–13047. DOI: 10.1021/es3018682. Includes excerpts from crude oil inventory data developed for this analysis from www.ucalgary.ca/lcaost/prelim.

Attachment KR-5. U.S. Chemical Safety and Hazard Investigation Board, 2013. *Interim Investigation Report: Chevron Richmond Refinery Fire;* final report adopted at Richmond, California on 19 April 2013.

Attachment KR-6. Excerpts from the *Chevron Refinery Modernization Project Environmental Impact Report;* State Clearinghouse No. 2011062042; Lead Agency: City of Richmond, California; excerpts including Appendix 4.3-URM (Unit Rate Model) and Six Element Test Reports. Richmond, CA.

Attachment KR-7. Excerpts from Valero Benicia Refinery permits including refinery capacity and utilization data: pages 8–37 from the Major Facility Review (Title V) Permit issued to the Valero Refining Co. Benicia Facility as revised by the Bay Area Air Quality Management District on 30 April 2013; and Attachment F-1 of Order No R2-2015-0037 for renewal of NPDES Permit No. CA0005550, adopted by the Valero Benicia Refinery by the San Francisco Bay Regional Water Quality Control Board on 12 August 2015.

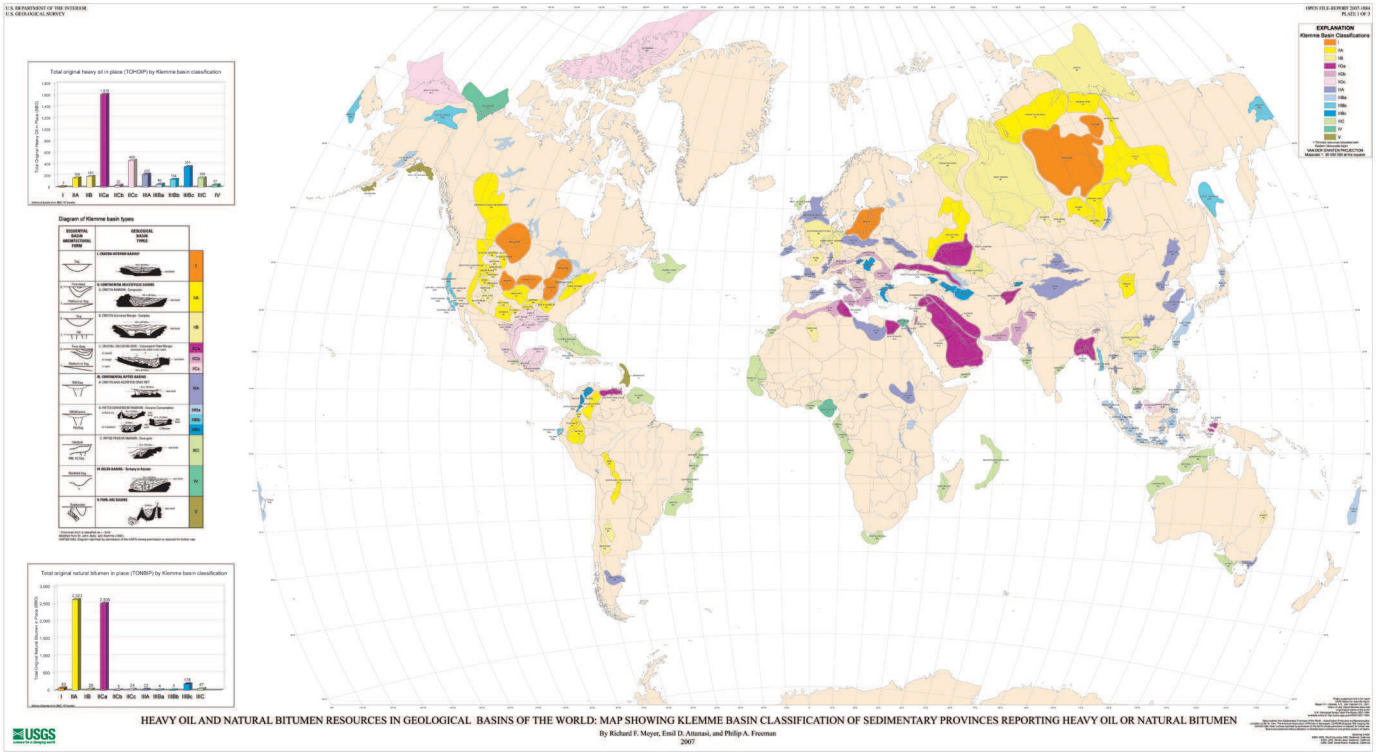
Attachment KR-8. U.S. Energy Information Administration, 2015. *PADD 5 Transportation Fuels Markets;* Energy Information Administration (USEIA), U.S. Department of Energy: Washington, D.C. September 2015.

Attachment KR-9. Cuffel, 2015. *Proposed Petroleum Refining Emissions Limits and Risk Thresholds Rule: Regulation 12, Rule 16, Comments from Valero.* Comments to the Bay Area Air Quality Management District dated 25 September 2015. Valero Refining Company-California: Benicia, CA.

Attachment KR–1

Meyer et al., 2007. *Heavy oil and natural bitumen resources in geological basins of the world;* U.S. Geological Survey (http://pubs.usgs.gov/of/2007/1084.
(Incorporated by reference in CBE supp. technical comments of 15 Sep 2014.)

Heavy Oil and Natural Bitumen Resources in Geological Basins of the World



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U.S. Department of the Interior
U.S. Geological Survey

Heavy Oil and Natural Bitumen Resources in Geological Basins of the World

By Richard F. Meyer, Emil D. Attanasi, and Philip A. Freeman

Open File-Report 2007–1084

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Heavy Oil and Natural Bitumen Resources in Geological Basins of the World

By Richard F. Meyer, Emil D. Attanasi, and Philip A. Freeman

Abstract

Heavy oil and natural bitumen are oils set apart by their high viscosity (resistance to flow) and high density (low API gravity). These attributes reflect the invariable presence of up to 50 weight percent asphaltenes, very high molecular weight hydrocarbon molecules incorporating many heteroatoms in their lattices. Almost all heavy oil and natural bitumen are alteration products of conventional oil. Total resources of heavy oil in known accumulations are 3,396 billion barrels of original oil in place, of which 30 billion barrels are included as prospective additional oil. The total natural bitumen resource in known accumulations amounts to 5,505 billion barrels of oil originally in place, which includes 993 billion barrels as prospective additional oil. This resource is distributed in 192 basins containing heavy oil and 89 basins with natural bitumen. Of the nine basic Klemme basin types, some with subdivisions, the most prolific by far for known heavy oil and natural bitumen volumes are continental multicyclic basins, either basins on the craton margin or closed basins along convergent plate margins. The former includes 47 percent of the natural bitumen, the latter 47 percent of the heavy oil and 46 percent of the natural bitumen. Little if any heavy oil occurs in fore-arc basins, and natural bitumen does not occur in either fore-arc or delta basins.

Introduction

Until recent years conventional, light crude oil has been abundantly available and has easily met world demand for this form of energy. By year 2007, however, demand for crude oil worldwide has substantially increased, straining the supply of conventional oil. This has led to consideration of alternative or insufficiently utilized energy sources, among which heavy crude oil and natural bitumen are perhaps the most readily available to supplement short- and long-term needs. Heavy oil has long been exploited as a source of refinery feedstock, but has commanded lower prices because of its lower quality relative to conventional oil. Natural bitumen is a very viscous crude oil that may be immobile in the reservoir. It typically requires upgrading to refinery feedstock grade (quality). When natural bitumen is mobile in the reservoir, it is generally known as extra-heavy oil. As natural asphalt, bitumen has been exploited since antiquity as a source of road paving, caulk, and mortar and is still used for these purposes in some parts of the world. The direct use of mined asphalt for road paving is now almost entirely local, having been replaced by manufactured asphalt, which can be tailored to specific requirements.

This study shows the geological distribution of known heavy oil and natural bitumen volumes by basin type. These data are presented to advance a clearer understanding of the relationship between the occurrence of heavy oil and natural bitumen and the type of geological environment in which these commodities are found. The resource data presented were compiled from a variety of sources. The data should not be considered a survey of timely resource information such as data published annually by government agencies and public reporting services. With the exception of Canada, no such data source on heavy oil and natural bitumen accumulations is available. The amounts of heavy oil yet unexploited in known deposits represent a portion of future supply. To these amounts may be added the heavy oil in presently poorly known and entirely unexploited deposits. Available information indicates cumulative production accounts for less than 3 percent of the discovered heavy oil originally in place and less than 0.4 percent of the natural bitumen originally in place.

Terms Defined for this Report

- Conventional (light) Oil: Oil with API gravity greater than 25°.
- Medium Oil: Oil with API gravity greater than 20°API but less than or equal to 25°API.
- Heavy Oil: Oil with API gravity between 10°API and 20°API inclusive and a viscosity greater than 100 cP.
- Natural Bitumen: Oil whose API gravity is less than 10° and whose viscosity is commonly greater than 10,000 cP. It is not possible to define natural bitumen on the basis of viscosity alone because much of it, defined on the basis of gravity, is less viscous than 10,000 cP. In addition, viscosity is highly temperature-

dependent (fig. 1), so that it must be known whether it is measured in the reservoir or in the stock tank. In dealing with Russian resources the term natural bitumen is taken to include both maltha and asphalt but excludes asphaltite.

- Total Original Oil in Place (TOOIP): Both discovered and prospective additional oil originally in place.
- Original Oil in Place-Discovered (OOIP-Disc.): Discovered original oil in place.
- Reserves (R): Those amounts of oil commonly reported as reserves or probable reserves, generally with no further distinction, and quantities of petroleum that are anticipated to be technically but not necessarily commercially recoverable from known accumulations. Only in Canada are reserves reported separately as recoverable by primary or enhanced methods. Russian reserve classes A, B, and C1 are included here (See Grace, Caldwell, and Hether,1993, for an explanation of Russian definitions.)
- Prospective Additional Oil in Place: The amount of resource in an unmeasured section or portion of a known deposit believed to be present as a result of inference from geological and often geophysical study.
- Original Reserves (OR): Reserves plus cumulative production. This category includes oil that is frequently reported as estimated ultimately recoverable, particularly in the case of new discoveries.

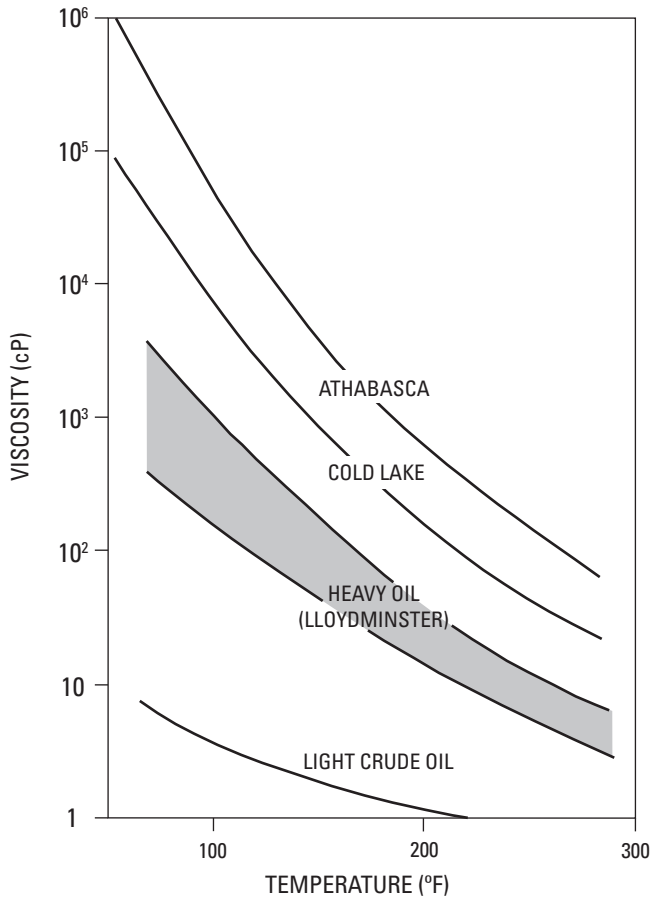

Figure 1. Response of viscosity to change in temperature for some Alberta oils (cP, centipoise), (Raicar and Proctor, 1984).

Chemical and Physical Properties

Fundamental differences exist between natural bitumen, heavy oil, medium oil, and conventional (light) oil, according to the volatilities of the constituent hydrocarbon fractions: paraffinic, naphthenic, and aromatic. When the light fractions are lost through natural processes after evolution from organic source materials, the oil becomes heavy, with a high proportion of asphaltic molecules, and with substitution in the carbon network of heteroatoms such as nitrogen, sulfur, and oxygen. Therefore, heavy oil, regardless of source, always contains the heavy fractions, the asphaltics, which consist of resins, asphaltenes, and preasphaltenes (the carbene-carboids) (Yen, 1984). No known heavy oil fails to incorporate asphaltenes. The large asphaltic molecules define the increase or decrease in the density and viscosity of the oil. Removal or reduction of asphaltene or preasphaltene drastically affects the rheological properties of a given oil and its aromaticity (Yen, 1984). Asphaltenes are defined formally as the crude oil fraction that precipitates upon addition of an n-alkane, usually n-pentane or n-heptane, but remains soluble in toluene or benzene. In the crude oil classification scheme of Tissot and Welte (1978), the aromatic-asphaltics and aromatic-naphthenics characterize the heavy oil and natural bitumen deposits of Canada and Venezuela and are the most important of all crude oil classes with respect to quantity of resources. The aromatic-intermediate class characterizes the deposits of the Middle East (Yen, 1984).

Some of the average chemical and physical properties of conventional, medium, and heavy crude oils and natural bitumen are given in table 1, in order to show their distinguishing characteristics. The data are derived from multiple sources, some old and others adhering to standards employed in different countries. The conversion factors outlined in table 2 were used to convert published data to a uniform standard. Some of the properties in table 1 are important with respect to heavy oil and natural recovery from the ground and other properties in table 1 serve as the basis for decisions for upgrading and refinery technologies. Moving across table 1 from conventional oil to natural bitumen, increases may be seen in density (shown as reductions in API gravity), coke, asphalt, asphaltenes, asphaltenes + resins, residuum yield (percent volume), pour point, dynamic viscosity, and the content of copper, iron, nickel, vanadium among the metals and in nitrogen and sulfur among the non-metals. Values diminish for reservoir depth, gasoline and gas-oil yields, and volatile organic compounds (VOC and BTEX –Benzene, Toluene, Ethylbenzene, and

Xylenes). The significance of these differences is often reflected in the capital and operating expenses required for the recovery, transportation, product processing, and environmental mitigation of the four oil types. The principal sources of analytical data for table 1 are Environmental Technology Centre (2003), Hyden (1961), Oil & Gas Journal Guide to Export Crudes (2006), U.S. Department of Energy, National Energy Technology Laboratory (1995), and various analyses published in technical reports.

The resins and asphaltenes play an important role in the accumulation, recovery, processing, and utilization of petroleum. The resins and asphaltenes are the final form of naphtheno-aromatic molecules. The carbon skeleton appears to comprise three to five polyaromatic sheets, with some heterocyclic (N-S-O) compounds. These crystallites may combine to form high molecular weight aggregates, with the high viscosity of heavy oils related to the size and abundance of the aggregates. Most asphaltenes are generated from kerogen evolution in response to depth and temperature increases in sedimentary basins. Different types of asphaltenes may be derived from the main kerogen types. Asphaltenes are not preferentially mobilized, as are light hydrocarbons during migration from source rocks to reservoir beds, where they are less abundant if the crude oil is not degraded (Tissot, 1981).

Some heavy oil and natural bitumen originates with chemical and physical attributes shown in table 1 as immature oil which has undergone little if any secondary migration. The greatest amount of heavy oil and natural bitumen results from the bacterial degradation under aerobic conditions of originally light crude oils at depths of about 5,000 feet or less and temperatures below 176°F. The consequence of biodegradation is the loss of most of the low molecular weight volatile paraffins and naphthenes, resulting in a crude oil that is very dense, highly viscous, black or dark brown, and asphaltic. An active water supply is required to carry the bacteria, inorganic nutrients, and oxygen to the oil reservoir, and to remove toxic by-products, such as hydrogen sulfide, with low molecular weight hydrocarbons providing the food (Barker, 1979). The low molecular weight components also may be lost through water washing in the reservoir, thermal fractionation, and evaporation when the reservoir is breached at the earth's surface (Barker, 1979). The importance of this process to the exploitation of heavy oil and natural bitumen lies in the increase of NSO (nitrogen-sulfur-oxygen) compounds in bacterially-altered crude oil and the increase in asphaltenes (Kallio, 1984).

Bacterial degradation of crude oil may also take place under anaerobic conditions, thus obviating the need for a fresh water supply at shallow depths (Head, Jones, and Larter, 2003; Larter and others, 2006). This proposal envisions degradation even of light oils at great depths so long as the maximum limiting temperature for bacterial survival is not exceeded. This theory does not account in any obvious way for the high percentage in heavy oil and natural bitumen of polar asphaltics, that is, the resins and asphaltenes.

Oil mass loss entailed in the formation of heavy oil and natural bitumen deposits has been the subject of numerous research studies. Beskrovnyi and others (1975) concluded that three to four times more petroleum was required than the reserves of a natural bitumen for a given deposit. Based upon material balance calculations in the Dead Sea basin, Tannenbaum, Starinsky, and Aizenshtat (1987) found indications that 75% of the original oil constituents in the C15+ range had been removed as a result of alteration processes. By accounting for the lower carbon numbers as well, they estimated that the surface asphalts represented residues of only 10-20% of the original oils. Head, Jones, and Larter (2003) diagram mass loss increasing from essentially zero for conventional oil to something more than 50% for heavy oils, which of themselves are subject to no more than 20% loss. Accompanying the mass loss is a decrease in API gravity from 36° to 5-20°; decrease in gas/oil ratio from 0.17 kg gas/kg oil; decrease in gas liquids from 20% to 2%; increase in sulfur from 0.3wt% to 1.5+wt%; and decrease in C15+ saturates from 75% to 35%. This calculation of mass loss shows: (1) the enormous amount of oil initially generated in heavy oil and natural bitumen basins, especially Western Canada Sedimentary and Eastern Venezuela basins; and (2) the huge economic burden imposed by this mass loss on the production-transportation-processing train of the remaining heavy oil and natural bitumen.

Origins of Heavy Oil and Natural Bitumen

It is possible to form heavy oil and natural bitumen by several processes. First, the oil may be expelled from its source rock as immature oil. There is general agreement that immature oils account for a small percentage of the heavy oil (Larter and others, 2006). Most heavy oil and natural bitumen is thought to be expelled from source rocks as light or medium oil and subsequently migrated to a trap. If the trap is later elevated into an oxidizing zone, several processes can convert the oil to heavy oil. These processes include water washing, bacterial degradation and evaporation. In this case, the biodegradation is aerobic. A third proposal is that biodegradation can also occur at depth in subsurface reservoirs (Head, Jones, and Larter, 2003; Larter and others, 2003; Larter and others, 2006). This explanation permits biodegradation to occur in any reservoir that has a water leg and has not been heated to more than 176° F. The controls on the biodegradation depend on local factors rather than basin-wide factors. Because the purpose of this report is to describe the geologic basin setting of the known heavy oil and natural bitumen deposits, it is beyond the scope of this report to argue the source or genesis of heavy oil and natural bitumen for each basin of the world.

Data Sources

Data for heavy oil resource occurrences and quantities for individual oilfields and reservoirs have been compiled from many published reports and commercial data bases. The most important of these include Demaison (1977), IHS Energy Group (2004), NRG Associates (1997), Parsons (1973), Roadifer (1987), Rühl (1982), and the U.S. Department of Energy, National Energy Technology Laboratory (1983, 2005)

Data for natural bitumen deposits in the United States are summarized in U.S Department of Energy, National Energy Technology Laboratory (1991), but information for Utah is taken from Oblad and others (1987) and Ritzma (1979). Although there is no single data source for deposits outside the United States, there is a rich literature, particularly for Russia and the countries of the Former Soviet Union. For Canada, reliance is placed on reports of the Alberta Energy and Utilities Board (2004) and Saskatchewan Industry and Resources (2003).

Resource Estimates

We consider the total original oil in place (OOIP) to be the most useful parameter for describing the location and volume of heavy oil and natural bitumen resources. Resource quantities reported here are based upon a detailed review of the literature in conjunction with available databases, and are intended to suggest, rather than define the resource volumes that could someday be of commercial interest. If only a recoverable volume of heavy oil for the accumulation was published, the discovered OOIP was computed according to the protocol set forth in table 3.

Natural bitumen originally in place is often reported in the literature. Where only a recoverable estimate is published, the in-place volumes were calculated according to the protocols given for heavy oil; this is especially the case for bitumen deposits above 4°API gravity, to which we arbitrarily refer as extra-heavy oil.

Poorly known deposits of heavy oil and natural bitumen are included in the category of prospective additional resources, as described in table 3. In no case are values for prospective additional resource volumes calculated as in the case of discovered resources but were taken directly from the published literature.

Table 4 summarizes the resources and essential physical parameters of the heavy oil and natural bitumen contained in each of the basin types. These characteristics affect heavy oil and natural bitumen occurrence and recovery. Recovery can be primary, as in the case of cold production without gravel packing, if the gas to oil ratio is high enough to provide necessary reservoir energy. Otherwise, recovery generally necessitates the application of enhanced recovery methods, such as thermal energy or the injection of solvents.

Recovery Methods

How the reservoir parameters apply to enhanced recovery is summarized from Taber, Martin, and Seright (1997a, 1997b) in table 5, which covers the most commonly used, or at least attempted enhanced oil recovery (EOR) methods. Of these methods, immiscible gas injection, polymer flooding, and *in situ* combustion (fireflood) have met with limited success for heavy oil and natural bitumen. Steam injection (cyclic steam, huff ‘n puff) has been most successful, frequently by use of cyclic steam, followed by steam flooding. Surface mining and cold *in situ* production are usually considered to be primary recovery methods. They can be suited to the extraction of heavy oil and natural bitumen under proper conditions.

Most of the process descriptions which follow are taken from Taber, Martin, and Seright (1997b). Many processes may result in the process agent, such as nitrogen or carbon dioxide, remaining immiscible with the reservoir hydrocarbon or else becoming miscible with it. The miscibility is dependent upon the minimum miscibility pressure (MMP) and determines the way in which the process agent achieves EOR. While this summary discussion shows the breadth of the EOR processes operators have tried and continue to try as experimental projects, thermal EOR methods account for most of the heavy oil that is commercially produced. Data on the frequency of the applications are taken, unless otherwise cited, from the Oil and Gas Journal Historical Review, 1980-2006 (2006), particularly the Oil and Gas Journal 2000 and 2006 EOR Surveys.

Nitrogen gas drive is low in cost and therefore may be used in large amounts. It is commonly used with light oils for miscible recovery. However, it may also be used for an immiscible gas flood. The Oil and Gas Journal 2000 Survey includes one immiscible nitrogen gas drive in a sandstone reservoir with 16˚API oil at 4,600 feet depth. It was reported to be producing 1,000 barrels per day (b/d) of enhanced production. The Journal’s 2006 Survey reports one each heavy oil nitrogen miscible and nitrogen immiscible projects. The miscible project is 19˚API, located in the Bay of Campeche, with 19 wells, but with no report of production capacity. The immiscible project has oil of 16˚API at 4,600 feet in sandstone. For this project total production is reported to be 1,500 b/d of which 1,000 b/d is enhanced by immiscible nitrogen injection.

Of the 77 CO2 projects in the Journal 2000 Survey, 70 are for miscible CO2 and none entails heavy oil. This is true also in the Journal 2006 Survey, where all 86 CO2 projects are devoted to light oil, above 28˚API. In the Journal 2000 Survey, five of the seven immiscible CO2 projects are applied to heavy oil reservoirs, four in clastics and one in limestone. The latter, in the West Raman field in Turkey, involves oil of 13°API, lies at 4,265 feet, and produces 8,000 b/d. The reservoir contains nearly two billion barrels of original oil in place. Recoverable reserves remain low because of the recalcitrance of the reservoir. Steam flooding has been unsuccessful. By the date of the Journal 2006, there are eight immiscible CO2 projects, with five of them entailing heavy oil amounting to 7,174 b/d. The

two largest projects are light oil and heavy oil and are each in carbonate reservoirs.

Polymer/chemical flooding includes micellar/polymer, alkaline-surfactant-polymer (ASP), and alkaline fluids (Taber, Martin, and Seright, 1997a, 1997b). Recovery is complex, leading to the lowering of interfacial tension between oil and water, solubilization of oil in some micellar systems, emulsification of oil and water, wettability alteration, and enhancement of mobility. Limitations and costs indicate for these floods the desirability of clean clastic formations. The Journal 2000 Survey shows five heavy oil polymer/chemical floods of 15°API in sandstone reservoirs at about 4,000 feet. They were producing about 366 b/d and the projects were deemed successful or promising. Projects such as these are below the desirable gravity limits and are more viscous than desired at 45 cP.

Polymer floods improve recovery over untreated water flood by increasing the viscosity of the water, decreasing thus the mobility of the water, and contacting a larger volume of the reservoir. The advantages of a polymer flood over a plain water flood are apparent. The Journal 2000 Survey lists 22 polymer flood projects, of which five involve heavy oil. These five are within the range of the polymer screen, although the gravities are marginal, lying from 13.5°API to a bit above 15°API. The five were producing 7,140 b/d, of which 2,120 b/d were attributed to EOR. The Journal 2006 Survey shows 20 polymer floods, with five exploring heavy oil reservoirs. Three of the five are producing 7,140 b/d total oil and 2,120 b/d of enhanced production.

The Journal 2000 Survey shows four hot water floods, one of which is heavy oil with a gravity of 12°API, viscosity of 900 cP, and starting saturation of only 15 percent. Project production was 300 b/d. Two of three hot water floods included in the Journal 2006 Survey are intended to enhance production of heavy oil. The two yield about 1,700 b/d of total oil and 1,700 b/d of enhanced hot water flood oil.

In situ combustion (fire flood) is theoretically simple, setting the reservoir oil on fire and sustaining the burn by the injection of air. Usually, the air is introduced through an injector well and the combustion front moves toward to the production wells. A variant is to include a water flood with the fire, the result being forward combustion with a water flood. Another variant is to begin a fire flood, then convert the initial well to a producer and inject air from adjacent wells. The problem with this reverse combustion is that it doesn't appear to work.

In situ combustion leads to oil recovery by the introduction of heat from the burning front, which leads to reduction in viscosity. Further, the products of steam distillation and thermal cracking of the reservoir oil are carried forward to upgrade the remaining oil. An advantage of the process is that the coke formed by the heat itself burns to supply heat. Lastly, the injected air adds to the reservoir pressure. The burning of the coke sustains the process so that the process would not work with light oil deficient in asphaltic components. The process entails a number of problems, some severe, but the Journal 2000 Survey shows 14 combustion projects, of which five are light oil and the remaining nine are heavy, between 13.5°API and 19°API. Viscosities and starting oil saturations are relatively high. It is notable that the heavy oil projects are in sandstones and the light oil in carbonates. The heavy oil *in situ* combustion projects were producing about 7,000 b/d. The Journal 2006 Survey includes nine heavy oil combustion projects among a total of twenty-one. The heavy oil projects yield about 7,000 b/d of combustion-enhanced oil, which ranges from 13.5˚API to 19˚API.

Steam injection for EOR recovery is done in two ways, either by cyclic steam injection (huff 'n puff) or continuous steam flood. Projects are frequently begun as cyclic steam, whereby a high quality steam is injected and soaks the reservoir for a period, and the oil, with lowered viscosity from the heat, is then produced through the injection well. Such soak cycles may be repeated up to six times, following which a steam flood is initiated. In general, steam projects are best suited to clastic reservoirs at depths no greater than about 4,000 feet, and with reservoir thicknesses greater than 20 feet and oil saturations above 40% of pore volume. For reservoirs of greater depth the steam is lowered in quality through heat loss to the well bore to where the project becomes a hot water flood. Steam is seldom applied to carbonate reservoirs in large part due to heat loss in fractures.

The Journal 2000 Survey lists 172 steam drive projects. Of these, four in Canada give no gravity reading, thirteen are medium oil from 22°API to 25°API, and the rest are heavy oil. The largest of all is at Duri field in Indonesia and this oil is 22°API. For the project list as a whole, the average gravity is 14°API, with a maximum value of 30°API and a minimum of 4°API. The average viscosity is 37,500 cP, with maximum and minimum values of 5,000,000 cP and 6 cP. Oil saturations range from 35% to 90%, the average being 68%. Most importantly, production from the project areas was 1.4 million b/d and of this, 1.3 million b/d was from steam drive EOR.

All but three of the 120 steam projects found in the Journal 2006 Survey entail recovery of heavy oil. The oil averages 12.9˚API, with a low value of 8˚API and a high of 28˚API (one of the three light oil reservoirs). The viscosity averages 58,000 cP, with a high value of 5 million cP and a low of 2 cP. The projects are yielding over 1.3 million b/d, virtually all being steam EOR.

Maps

The geographic distribution of basins reporting heavy oil and natural bitumen, as identified by their Klemme basin types, appears on Plate 1. A diagram of the Klemme basin classification illustrates the architectural form and the geological basin structure by type. This plate also includes histograms of the total original oil in place resource volumes of both heavy oil and natural bitumen. Plates 2 and 3, respectively, depict the worldwide distribution of heavy oil and natural bitumen resources originally in place. Each map classifies basins

by the reported volumes of total original oil in place. A table ranks the basins by total original oil in place volumes besides indicating Klemme basin type and reporting discovered original oil in place and prospective additional oil in place. Plates 2 and 3 also include an inset map of the geographic distribution of original heavy oil or natural bitumen by 10 world regions (see table 6 for regional listing of countries reporting heavy oil or natural bitumen.)

Basin outlines of the sedimentary provinces are digitally reproduced from the AAPG base map compiled by St. John (1996). The basin outlines of St. John (1996) are unaltered. However, the reader should note that the basin outlines are considered to be generalizations useful for displaying the resource distributions but are less than reliable as a regional mapping tool. Also, some basin names have been changed to names more commonly used by geologists in the local country. These equivalent names and the original names from Bally (1984) and St. John (1996) are detailed in table 1-1 in Appendix 1. The basin outline for Eastern Venezuela as shown does not include the island of Trinidad where both heavy oil and natural bitumen resources occur. For this report, resources from Trinidad and Tobago are reported in the Eastern Venezuela basin totals. In a few cases a single basin as outlined on the plates is composed of multiple basins to provide more meaningful local information. This is particularly true in the United States, where the AAPG-CSD map was employed (Meyer, Wallace, and Wagner, 1991). In each case, the individual basins retain the same basin type as the basin shown on the map and all such basins are identified in Appendix 1.

Basins having heavy oil or natural bitumen deposits are listed in table 2-1 in Appendix 2 along with the Klemme basin type, countries and U.S. states or Canadian provinces reporting deposits and other names cited in literature. The Klemme basin classification diagram in Plate 1 is reprinted in fig. 3-1 in Appendix 3 for the reader's convenience. The tables from Plates 2 and 3 are reprinted as table 4-1 and table 4-2 for the reader's convenience.

Klemme Basin Classification

Many classifications of petroleum basins have been prepared. In one of the earliest, Kay (1951) outlined the basic architecture of geosynclines, with suggestions as to their origins. Kay's work preceded the later theory of plate tectonics. Klemme (1977, 1980a, 1980b, 1983, 1984) gives a summary description of petroleum basins together with their classification, based upon basin origin and inherent geological characteristics. This classification is simple and readily applicable to the understanding of heavy oil and natural bitumen occurrence. The Klemme basin types assigned to the heavy oil and natural bitumen basins described in this report correspond to the assignments made in St. John, Bally, and Klemme (1984). In some cases of multiple type designations in St. John, Bally, and Klemme (1984) a unique type designation was resolved by reference to Bally (1984) or Bally and Snelson (1980). Only a few of the basins originally designated as multiple types in St. John, Bally and Klemme (1984) appear to contain heavy oil and natural bitumen.

Table 7 summarizes the criteria upon which Klemme based his classification. The general description of the resource endowment associated to the Klemme basin classification is based upon oilfield (and gasfield) data of the world as of 1980 without regard to the density or other chemical attributes of the hydrocarbons they contain (Klemme, 1984). At the time of Klemme's work, the average density U.S. refinery crude oil was about 33.7°API (Swain, 1991). A decline in the average to about 30.6°API by 2003 perhaps signifies the increasing importance of heavy oil in the mix (Swain, 2005).

Generally, basins may be described as large or small and linear or circular in shape. They may also be described by the ratio of surface area to sedimentary volume. The basement profile or basin cross-section, together with the physical description, permits the interpretation of the fundamental basin architecture. The basin can then be placed within the relevant plate tectonic framework and assigned to one of four basin types, of which two have sub-types. A diagram of the Klemme basin types appears on Plate 1, color-coded to the basins on the map.

In the following section we provide descriptions of the basin types from Klemme (1980b, 1983, 1984) followed by discussion of the heavy oil and natural bitumen occurrences within those same basin types, summary data for which are given in table 4. Because most heavy oil and natural bitumen deposits have resulted from the alteration of conventional and medium oil, the factors leading to the initial conventional and medium oil accumulations are relevant to the subsequent occurrence of heavy oil and natural bitumen.

Type I. Interior Craton Basins

The sediment load in these basins is somewhat more clastic than carbonate. Reservoir recoveries are low and few of the basins contain giant fields. Traps are generally related to central arches, such as the Cincinnati arch, treated here as a separate province (Plates 1-3), or the arches of the Siberian platform (see below for further explanation). Traps also are found in smaller basins over the craton, such as the Michigan basin. The origin of these depressions is unclear although most of them began during the Precambrian (Klemme, 1980a, 1980b).

The six Type I basins having heavy oil contain less than 3 billion barrels of oil in place and of this 93% occurs in the Illinois basin alone. Four Type I basins that contain natural bitumen have 60 billion barrels of natural bitumen in place, with nearly 99% in the Tunguska basin in eastern Siberia and the rest in the Illinois basin. The Tunguska basin covers most of the Siberian platform, around the borders of which are found cratonic margin basins of Type IIA. For convenience all the resource is assigned to the Tunguska basin. The prospec-

tive additional resource of 52 billion barrels is almost certainly an absolute minimum value for this potentially valuable but difficult to access area (Meyer and Freeman, 2006.)

Type II. Continental Multicyclic Basins

Type IIA. Craton margin (composite)

These basins, formed on continental cratonic margins, are generally linear, asymmetrical in profile, usually beginning as extensional platforms or sags and ending as compressional foredeeps. Therefore they are multicyclic basins featuring a high ratio of sediment volume to surface area. Traps are mainly large arches or block uplifts and may be found in rocks of either the lower (platform) or upper (compression) tectonic cycle. About 14% of conventional oil discovered in the world by 1980 is from marginal cratonic basins (Klemme, 1980a, 1980b).

Type IIA basins are of moderate importance with respect to heavy oil, with about 158 billion barrels of oil in place distributed among 28 basins. Three Type IIA basins, the Western Canada Sedimentary, Putumayo, and Volga-Ural, have combined total heavy oil resource of 123 billion barrels of oil in place, or 78% of the total for Type IIA basins.

In comparison, natural bitumen in 24 Type IIA basins accounts for 2,623 billion barrels of natural bitumen in place, or nearly 48% of the world natural bitumen total. The Western Canada Sedimentary basin accounts for 2,334 billion barrels of natural bitumen in place, or about 89%. Of the Canadian total, 703 billion barrels of natural bitumen in place is prospective additional oil, largely confined to the deeply buried bitumen in the carbonate that underlie the Peace River and part of the Athabasca oil sand deposit in an area known as the Carbonate Triangle. The significance of the Canadian deposits lies in their concentration in a few major deposits: Athabasca, from which the reservoir is exploited at or near the surface and shallow subsurface, and Cold Lake and Peace River, from which the bitumen is extracted from the subsurface. Two other basins contain much less but still significant amounts of natural bitumen, the Volga-Ural basin in Russia (263 billion barrels of natural bitumen in place) and the Uinta basin in the United States (12 billion barrels of natural bitumen in place). The Volga-Ural deposits are numerous, but individually are small and mostly of local interest. The Uinta deposits are much more concentrated aerially, but are found in difficult terrain remote from established transportation and refining facilities.

Type IIB. Craton accreted margin (complex)

These basins are complex continental sags on the accreted margins of cratons. Architecturally, they are similar to Type IIA basins, but begin with rifting rather than sags. About three-quarters of Type IIA and IIB basins have proven productive, and they contain approximately one-fourth of the world's total oil and gas (Klemme, 1980a, 1980b).

The 13 Type IIB basins contain a moderate amount of heavy oil (193 billion barrels of oil in place). The two most significant basins are in Russia, West Siberia and Timan-Pechora. These, together with most of the other Type IIB heavy oil basins, are of far greater importance for their conventional and medium oil resources.

Five Type IIB basins hold 29 billion barrels of natural bitumen in place. Only the Timan-Pechora basin contains significant natural bitumen deposits, about 22 billion barrels of natural bitumen in place. Unfortunately, this resource is distributed among a large number of generally small deposits.

Type IIC. Crustal collision zone (convergent plate margin)

These basins are found at the crustal collision zone along convergent plate margins, where they are downwarped into small ocean basins. Although they are compressional in final form, as elongate and asymmetrical foredeeps, they begin as sags or platforms early in the tectonic cycle. Type IIC downwarp basins encompass only about 18 percent of world basin area, but contain nearly one-half of the world's total oil and gas. These basins are subdivided into three subtypes, depending on their ultimate deformation or lack thereof: Type IICa, closed; Type IICb, trough; and Type IICc, open (Klemme, 1980a, 1980b).

Although basins of this type begin as downwarps that opened into small ocean basins (Type IICc), they may become closed (Type IICa) as a result of the collision of continental plates. Upon closing, a large, linear, asymmetric basin with sources from two sides is formed, resembling a Type IIA basin. Further plate movement appears to destroy much of the closed basin, leaving a narrow, sinuous foredeep, that is, a Type IICb trough. Relatively high hydrocarbon endowments in the open and the closed types may be related to above-normal geothermal gradients, which accentuates hydrocarbon maturation and long-distance ramp migration. Traps are mostly anticlinal, either draping over arches or compressional folds, and are commonly related to salt flowage.

Type IICa basins, with their architectural similarity to Type IIA basins, are the most important of the three Type IIC heavy oil basins. The 15 basins account for 1,610 billion barrels of the heavy oil in place, with the Arabian, Eastern Venezuela, and Zagros basins containing 95% of the total. Of particular interest is the Eastern Venezuela basin which includes large accumulations of conventional and medium oil, while at the same time possessing an immense resource of both heavy oil and natural bitumen.

Type IICa basins also are rich in natural bitumen, with a total of 2,507 billion barrels of natural bitumen in place among the six. About 83% of this occurs in Venezuela, mostly in the southern part of the Eastern Venezuelan basin known as the Orinoco Oil Belt. Here the reservoir rocks impinge upon the

Guyana craton in much the same fashion as the reservoir rocks of the Western Canada Sedimentary basin lap onto the Canadian shield. The only other significant Type IICa accumulation of natural bitumen is found in the North Caspian basin (421 billion barrels of natural bitumen in place).

Fourteen Type IICb basins contain modest amounts of heavy oil (32 billion barrels of oil in place) and even less of natural bitumen (5 billion barrels of natural bitumen in place in seven basins). Much of this resource is found in the Caltanisetta and Durres basins, on either side of the Adriatic Sea. Durres basin resources are aggregated with the South Adriatic and the province is labeled South Adriatic on the plates. Significant amounts of the Caltanisetta resource occurs offshore.

The amount of heavy oil in the 12 Type IICc basins is substantial (460 billion barrels of oil in place). The Campeche, by far the largest, and Tampico basins in Mexico and the North Slope basin in the United States account for 89% of the heavy oil. The Campeche field, which is actually an assemblage of closely associated fields, is found about 65 miles offshore of the Yucatan Peninsula in the Gulf of Mexico. The North Slope basin, on the north coast of Alaska, occurs in an area of harsh climate and permafrost, which makes heavy oil and natural bitumen recovery by the application of thermal (steam) methods difficult both physically and environmentally. The U.S. fields in the East Texas, Gulf Coast, and Mississippi Salt Dome basins account for only 5% of the heavy oil in basins of this type.

Only a small amount of natural bitumen (24 billion barrels) has been discovered in eight Type IICc basins. Two of these, the North Slope and South Texas Salt Dome basins, are significant for possible future development.

Type III. Continental Rifted Basins

Type IIIA. Craton and accreted zone (rift)

These are small, linear continental basins, irregular in profile, which formed by rifting and simultaneous sagging in the craton and along the accreted continental margin. About two-thirds of them are formed along the trend of older deformation belts and one-third are developed upon Precambrian shields. Rifts are extensional and lead to block movements so that traps are typically combinations. Oil migration was often lateral, over short distances. Rift basins are few, about five percent of the world's basins, but half of them are productive. Because of their high recovery factors, Type IIIA basins accounted for 10% of the world's total recoverable oil and gas in 1980 (Klemme, 1980a, 1980b).

Globally, there are 28 Type IIIA heavy oil basins, containing 222 billion barrels of oil in place The Bohai Gulf basin in China accounts for 63% of the heavy oil, with an additional 11% derived from the Gulf of Suez and 10% from the Northern North Sea. Outside of these, most Type IIIA basins contain just a few deposits. The five basins in Type IIIA have almost 22 billion barrels of natural bitumen in place, but half of that is located in the Northern North Sea basin.

Type IIIB. Rifted convergent margin (oceanic consumption)

Type IIIBa basins are classified as back-arc basins on the convergent cratonic side of volcanic arcs. They are small, linear basins with irregular profiles (Klemme, 1980a, 1980b).

Not unlike Type IIIA basins, the volume of heavy oil found in the Type IIIBa basins is small. Seventeen heavy oil basins contain 49 billion barrels of oil in place and 83% of this amount is in Central Sumatra.

Just 4 billion barrels of natural bitumen in place are identified in the Type IIIA basin called Bone Gulf. Small amounts are also known to occur in the Cook Inlet and Tonga basins.

Type IIIBb basins are associated with rifted, convergent cratonic margins where wrench faulting and subduction have destroyed the island arc. They are small, linear, and irregular in profile.

The 14 Type IIIBb basins containing heavy oil account for only 134 billion barrels of oil in place. These basins are only moderately important on a global scale, but have been very important to the California oil industry. The seven such basins of California - Central Coastal, Channel Islands, Los Angeles, Sacramento, San Joaquin, Santa Maria, and Ventura – equal 129 billion barrels of oil in place or 96%.

There are nine Type IIIBb basins that report natural bitumen deposits. They contain 4 billion barrels of natural bitumen in place, about half of which is in the Santa Maria basin.

Types IIIBa and IIIBb basins comprise about seven percent of world basin area, but only one-quarter of the basins are productive for oil of all types. However, the productive ones, which represent only two percent of world basin area, yield about seven percent of total world's oil and gas (Klemme, 1983). Some of these productive basins, particularly those located in California, have high reservoir recovery factors.

Type IIIBc basins are small and elongate, irregular in profile, and occupy a median zone either between an oceanic subduction zone and the craton or in the collision zone between two cratonic plates. They result from median zone wrench faulting and consequent rifts. Such basins make up about three and one-half percent of world basin area and contribute two and one-half percent of total world oil and gas.

Type IIIBc basins are important to the occurrence of heavy oil (351 billion barrels of oil in place). Although there are nine basins of this type, 92% of the heavy oil is concentrated in the Maracaibo basin. The Maracaibo basin also yields 95% of the 178 billion barrels of natural bitumen in place in the five basins containing this type of oil. This makes the Maracaibo basin unique: no other basin type is so completely dominated by a single basin.

Type IIIC. Rifted passive margin (divergence)

These basins, often aptly called pull-apart basins, are extensional, elongate, and asymmetric. Located along major oceanic boundaries of spreading plates, they are divergent and occupy the intermediate zone between thick continental crust and thin oceanic crust. They appear to begin with a rifting stage, making possible the later sedimentary fill from the continent. Type IIIC basins, comprising 18 percent of the world's basin area, are mostly offshore and are often in water as deep as 5,000 feet. For this reason their development has been slow but is accelerating as traditional, easily accessible basins reach full development and world demand for petroleum increases (Klemme, 1980a, 1980b).

Twenty-eight Type IIIC basins yield 158 billion barrels of heavy oil in place, but one, the offshore Campos basin, contains 66% of this heavy oil. These continental margin basins must at some point in their histories have been sufficiently elevated to permit their generated conventional oil to be degraded. It is possible that the heavy oil could be very immature, having undergone only primary migration and later elevation. The geologic history of such basins does not encourage this view. However, the oil could well have been degraded bacterially at depth according to the recently proposed mechanisms suggested by Head, Jones, and Larter (2003) and Larter and others (2006). In a pull-apart basin the sediments would have accumulated rapidly and at depth, the expressed oil then was subject to degradation. The problem with degradation at depth is the loss of mobility unless it can be demonstrated that the oil was never elevated and, in fact, the Campos basin oil is deep, occurring at an average depth of nearly 8,400 feet.

The bitumen resource in Type IIIC basins is small (47 billion barrels of natural bitumen in place in seven basins), as are nearly all bitumen occurrences in comparison with the Western Canada Sedimentary and Eastern Venezuela basins. But the 38.3 billion barrels of natural bitumen in place in the Ghana basin of southwestern Nigeria is exploitable and the amount of the resource may be understated. Like many bitumen deposits it awaits more detailed evaluation.

Type IV. Delta (Tertiary to recent)

Deltas form along continental margins as extensional sags, are circular to elongate, and show an extremely high ratio of sediment fill to surface area. Architecturally, they are modified sags comprised of sediment depocenters and occur along both divergent and convergent cratonic margins. Although by 1980 delta basins provide two and one-half percent of world basin area and perhaps six percent of total oil and gas (Klemme, 1980a, 1980b), they account for more of the conventional resource endowment with the recent successful exploration in frontier deep water areas.

The three Type IV delta basins produce scant heavy oil (37 billion barrels of oil in place) and no natural bitumen. This is related to the extremely high ratio of sediment fill to surface area and that these basins exhibited rapid burial of the source organic matter. Burial is constant and uninterrupted, providing very limited opportunity for degradation of the generated petroleum.

Type V. Fore-Arc Basins

Fore-arc basins are located on the ocean side of volcanic arcs. They result from both extension and compression, are elongate and asymmetrical in profile, and architecturally are the result of subduction. Fore-arc basins are few in number and generally not very productive (Klemme, 1980a, 1980b).

Very small amounts of heavy oil are found in the Barbados basin. Although a natural bitumen deposit is reported in the Shumagin basin, volume estimates are not available.

Essentially no heavy oil or natural bitumen is found in fore-arc basins because these basins do not generate large quantities of petroleum of any type and therefore provide relatively little material to be degraded.

Regional Distribution of Heavy Oil and Natural Bitumen

The preceding discussion has been concerned with the distribution of heavy oil and natural bitumen in the world's geological basins. This is of paramount interest in the exploration for the two commodities and for their exploitation. The chemical and physical attributes of the fluids and the reservoirs which contain them do not respect political boundaries.

At the same time it is necessary to understand the geography of the heavy oil and natural bitumen for both economic and political reasons. These factors will be dealt with in detail in a subsequent report. The bar graphs on Plates 2 and 3 give the regional distribution of total and discovered original oil in-place for heavy oil and natural bitumen, respectively. The distribution of the resources is given in table 8. The western hemisphere accounts for about 52 percent of the world's heavy oil and more than 85 percent of its natural bitumen. The Middle East and South America have the largest in-place volumes of heavy oil, followed by North America. North and South America have, by far, the largest in-place volumes of natural bitumen. Very large resource deposits are also known in eastern Siberia but insufficient data are available to make more than nominal size estimates.

Summary

From the preceding basin discussion, Klemme basin Type IICa is by far the most prolific in terms of heavy oil. For natural bitumen Klemme basin Type IIA and Type IICa are the most prolific. The basin types involved are architecturally analogous, beginning with depositional platforms or sags

and ending up as foredeeps. They differ only in their modes of origin. What they have in common is truncation against cratonic masses updip from rich source areas. This situation permitted immense accumulations of conventional oil at shallow depths, with near ideal conditions for oil entrapment and biodegradation resulting in formation of heavy oil and bitumen accumulations. The prospective resources from the prospective additional resource deposits in these basins are larger than the discovered resources of many basin types.

The Klemme basin classification system includes elements of basin development and architecture that control basin type. The observed pattern of the heavy oil and natural bitumen occurrences across basin types is consistent with the formation of heavy oil and natural bitumen through the process of degradation of conventional oil. Only relatively small quantities of heavy oil were found in the Interior Craton (Type I), Deltas (Type IV) and Fore-Arc basins (Type V).

Type IICa basins, including the Arabian, Eastern Venezuela, and Zagros, have the largest endowments of heavy oil and also contain the largest amounts of conventional oil. Large volumes of heavy oil are also found in both Type IICc basins, notably, the Campeche, Tampico, and North Slope basins, and in Type IIIBc basins, primarily Maracaibo basin. For natural bitumen, the Western Canada Sedimentary and Eastern Venezuela basins have similar development histories and basin architectural features. Some basin development patterns promote the formation of greater volumes of heavy oil and natural bitumen than others. This is seen most clearly in present occurrences of heavy oil and natural bitumen in the Type IICa and Type IICc basins, with their rich source areas for oil generation and up-dip migration paths to entrapment against cratons. Conventional oil may easily migrate through the tilted platforms until the platforms are breached at or near surface permitting deveopment of asphaltic seals.

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Tables 1–8

Table 1. Some chemical and physical attributes of crude oils (averages).

[cP, centipoise; wt%, weight percent; mgKOH/g, milligrams of potassium hydroxide per gram of sample; sp gr, specific gravity; vol%, volume percent; ppm, parts per million; Concarbon, Conradson carbon; VOC, volatile organic compounds; BTEX, benzene, toluene, ethylbenzene, and xylenes]

Attribute	Unit	Conventional oil (131 basins, 8148 deposits)	Medium oil (74 basins, 774 deposits)	Heavy oil (127 basins, 1199 deposits)	Natural bitumen (50 basins, 305 deposits)
API gravity	degrees	38.1	22.4	16.3	5.4
Depth	feet	5,139.60	3,280.20	3,250.00	1,223.80
Viscosity (77°F)	cP	13.7	34	100,947.00	1,290,254.10
Viscosity (100°F)	cP	10.1	64.6	641.7	198,061.40
Viscosity (130°F)	cP	15.7	34.8	278.3	2,371.60
Conradson Carbon	wt%	1.8	5.2	8	13.7
Coke	wt%	2.9	8.2	13	23.7
Asphalt	wt%	8.9	25.1	38.8	67
Carbon	wt%	85.3	83.2	85.1	82.1
Hydrogen	wt%	12.1	11.7	11.4	10.3
Nitrogen	wt%	0.1	0.2	0.4	0.6
Oxygen	wt%	1.2		1.6	2.5
Sulfur	wt%	0.4	1.6	2.9	4.4
Reid vapor pressure	psi	5.2	2.6	2.2	
Flash point	°F	17	20.1	70.5	
Acid number	mgKOH/g	0.4	1.2	2	3
Pour point	°F	16.3	8.6	19.7	72.9
C1-C4	vol%	2.8	0.8	0.6	
Gasoline + naphtha	vol%	31.5	11.1	6.8	4.4
Gasoline + naphtha	sp gr	0.76	0.769	0.773	0.798
Residuum	vol%	22.1	39.8	52.8	62.2
Residuum	sp gr	0.944	1.005	1.104	1.079
Asphaltenes	wt%	2.5	6.5	12.7	26.1
Asphaltenes + resins	wt%	10.9	28.5	35.6	49.2
Aluminum	ppm	1.174	1.906	236.021	21,040.03
Copper	ppm	0.439	0.569	3.965	44.884
Iron	ppm	6.443	16.588	371.05	4,292.96
Mercury	ppm	19.312	15	8.74	0.019
Nickel	ppm	8.023	32.912	59.106	89.137
Lead	ppm	0.933	1.548	1.159	4.758
Titanium	ppm	0.289	0.465	8.025	493.129
Vanadium	ppm	16.214	98.433	177.365	334.428
Residue Concarbon	wt%	6.5	11.2	14	19
Residue Nitrogen	wt%	0.174	0.304	0.968	0.75
Residue Nickel	ppm	25.7	43.8	104.3	
Residue Sulfur	ppm	1.5	3.2	3.9	
Residue Vanadium	ppm	43.2	173.7	528.9	532
Residue viscosity (122°F)	cP	1,435.80	4,564.30	23,139.80	
Total BTEX volatiles	ppm	10,011.40	5,014.40	2,708.00	
Total VOC volatiles	ppm	15,996.30	8,209.20	4,891.10	

Table 2. Conversion factors and equivalences applied to standardize data.

Standard unit in this report	Units as reported in literaure	Formula
	API gravity	
°API (degrees)	specific gravity (sp gr), (g/cm³)	= (141.5/(sp gr))-131.5
	Area	
acre	square mile (mi²)	= (1/640) mi²
	square kilometer (km^2)	= 0.00405 km^2
	hectare (ha)	= 0.405 ha
	Asphalt in crude	
weight percent (wt%)	Conradson Carbon Residue (CCR)	= 4.9× (CCR)
	Barrels of oil	
barrel (bbl), (petroleum, 1 barrel=42 gal)	cubic meter (m³)	= 0.159 m³
	metric tonne (t)	= 0.159× (sp gr) ×t
	Coke in crude	
weight percent (wt%)	Conradson Carbon Residue (CCR)	= 1.6× (CCR)
	Gas-oil ratio	
cubic feet gas/barrel oil (ft³ gas/bbl oil)	cubic meters gas/cubic meter oil (m³ gas/m³ oil)	= 0.18× (m³gas/m³oil)
	Parts per million	
parts per million (ppm)	gram/metric tonne (g/t)	= g/t
	milligram/kilogram (mg/kg)	= mg/kg
	microgram/gram (µg/g)	= µg/g
	milligram/gram (mg/g)	= 0.001 mg/g
	weight percent (wt%)	= 0.0001 wt%
	Parts per billion	
parts per billion (ppb)	parts per million (ppm)	= 0.001 ppm
	Permeability	
millidarcy (md)	micrometer squared (μm^2)	= 1,000 μm^2
	Pressure	
pound per square inch (psi)	kilopascal (kPa)	= 6.89 kPA
	megapascal (Mpa)	= 0.00689 MPa
	bar	= 0.0689 bar
	kilograms/square centimeter (kg/cm^2)	= 0.0703 kg/cm^2
	Specific gravity (density)	
specific gravity (sp gr), (g/cm³)	°API (degrees)	= 141.5/(131.5+°API)
	Temperature	
degrees Fahrenheit (°F)	degrees Celsius (°C)	= (1.8×°C)+32
degrees Celsius (°C)	degrees Fahrenheit (°F)	= 0.556×(°F-32)
	Viscosity (absolute or dynamic)	
centipoise (cP)	Pascal second (Pa·s)	= 0.001 Pa·s
	millipascal second (mPa·s)	= mPa·s

Table 2. Conversion factors and equivalences applied to standardize data.—Continued

Standard unit in this report	Units as reported in literaure	Formula
	Viscosity (absolute or dynamic)—Continued	
centipoise (cP)—cont.	kinematic viscosity[1]: centistroke (cSt), (mm²/sec)	= cSt × (sp gr)
	Saybolt Universal Seconds (SUS) at 100°F, for given density	= (SUS /4.632)× (sp gr)
	Saybolt Universal Seconds (SUS) at 100°F, for given °API	= (SUS /4.632)×(141.5/(131.5+°API))
	Weight percent	
weight percent (wt%)	parts per million (ppm)	= 10,000 ppm

[1] Kinematic viscosity is equal to the dynamic viscosity divided by the density of the fluid, so at 10°API the magnitudes of the two viscosities are equal.

Table 3. Total original in place resource calculation protocol when discovered oil in place is unavailable.

Define—

- OOIP-disc.: Original Oil In Place, discovered
- RF: Recovery factor (%)
- R: Reserves, known
- OR: Reserves, original sometimes called, known recovery, ultimate production if so reported
- AP: Production, annual
- CP: Production, cumulative
- PA: Prospective additional oil in place resource
- TOOIP = Total original oil in place

Calculations are based given data, which always receives priority; CP, AP and PA are never calculated and must be from published sources. (Assume CP, AP, PA are given)—

- R = 20×AP. This assumes a 20-year life or production plan for the viscous oil.
- OR = R+CP
- RF = 0.1 for clastic reservoirs or if no lithology is reported
- RF = 0.05 for carbonate reservoirs
- OOIP-disc. = OR/RF
- TOOIP = OOIP-disc. + PA

Table 4. Heavy oil and natural bitumen resources in billions of barrels of oil (BBO) and average characteristics of heavy oil and natural bitumen by basin type. Average values for gravity, viscosity, depth, thickness permeability are weighted by volume of oil in place discovered in each heavy oil or natural bitumen deposit by basin type; except for API gravity of heavy oil Type I, where because of relatively few deposits and several outlier values, a trimmed weighted mean value is shown.

[Volumes may not add to totals due to independent rounding; BBO, billions of barrels of oil; cP, centipoise]

Basin type	Total original oil in place (BBO)	Discovered oil in place (BBO)	API gravity (degrees)	Viscosity (cP @ 100°F)	Depth (feet)	Thickness (feet)	Porosity (percent)	Permeability (millidarcy)	Temperature (°F)
Heavy oil									
I…….	3	2	15.9	724	1,455	11	15.3	88	122
IIA…….	158	157	16.3	321	4,696	36	22.8	819	102
IIB…….	181	181	17.7	303	3,335	96	27.2	341	82
IICa…...	1,610	1,582	15.5	344	3,286	150	24	242	144
IICb…...	32	32	15.4	318	3,976	161	16.9	2,384	126
IICc…...	460	460	17.8	455	6,472	379	19.6	1,080	159
IIIA……	222	222	16.3	694	4,967	279	24.9	1,316	159
IIIBa…..	49	49	19.2	137	558	838	24.9	2,391	122
IIIBb…..	134	134	15.8	513	2,855	390	31.9	1,180	116
IIIBc…..	351	351	13.5	2,318	4,852	142	20.1	446	145
IIIC……	158	158	17.2	962	7,227	273	25.1	868	159
IV……..	37	37	17.9	-	7,263	1,195	27.9	1,996	155
V……	<1	<1	18	-	1,843	135	30	-	144
All types	3,396	3,366	16	641	4,213	205	23.7	621	134
Natural bitumen									
I…….	60	8		-	20	317	5.5	100	
IIA…….	2,623	1,908	6.8	185,407	223	53	0.4	611	173
IIB…….	29	26	4.5	-		209	13.1	57	113
IICa…...	2,509	2,319	4.4	31,789	806	156	29.8	973	174
IICb…...	5	5	6.8	-	8,414	1,145	4.7	570	181
IICc…...	24	23	5	1,324	3,880	82	32.4	302	263
IIIA……	22	22	8.7	-	4,667	882	30.3	1,373	85
IIIBa…..	4	4	-	-	-	-	-	-	-
IIIBb…..	3	3	6.7	500,659	3,097	586	28.6	2,211	89
IIIBc…..	178	178	9.5	1,322	8,751	52	34	751	139
IIIC……	47	14	7.3	-	900	103	23.1	2,566	117
IV……..	0	0							
V……	0	0							
All types	5,505	4,512	4.9	198,061	1,345	110	17.3	952	158

Table 5. Enhanced oil recovery (EOR) methods for heavy oil showing primary reservoir threshold criteria.

[modified from Taber, Martin, and Seright (1997a,b); cP, centipoises; PV, pore volume; ft, feet; md, millidarcy; °F, degrees Fahrenheit, wt%, weight percent]

Method	Gravity (°API)	Viscosity (cP)	Oil composition	Oil saturation (%PV)	Lithology	Net thickness (ft)	Average permeability (md)	Depth (ft)	Temperature (°F)
Immiscible gases									
Immiscible gases[a]	>12	<600	Not critical	>35	Not critical	Not critical	Not critical	>1,800	Not critical
Enhanced waterflood									
Polymer	>15	<150	Not critical	>50	Sandstone preferred	Not critical	>10[b]	<9,000	>200-140
Thermal/mechanical									
Combus-tion	>10	<5,000	Asphaltic compo-nents	>50	Highly porous sandstone	>10	>50[c]	<11,500	>100
Steam	>8	<200,000	Not critical	>40	Highly porous sandstone	>20	>200[d]	<4500	Not critical
Surface mining	>7	0 cold flow	Not critical	>8 wt% sand	Mineable oil sand	>10[e]	Not critical	>3:1 over-burden: sand ratio	Not critical

[a] Includes immiscible carbon dioxide flood.

[b] >3 md for some carbonate reservoirs if the intent is to sweep only the fracture systems.

[c] Transmissibility > 20md-ft/cP.

[d] Transmissibility > 50md-ft/cP.

[e] See depth.

Table 6. Listing of countries reporting deposits of heavy oil and/or natural bitumen grouped by region. (See inset maps of regional distribution on Plates 2 and 3.)

North America	South America	Europe	Africa	Transcaucasia	Middle East	Russia	South Asia	East Asia	Southeast Asia and Oceania
Canada	Argentina	Albania	Algeria	Azerbaijan	Bahrain	Russia	Bangladesh	China	Australia
Mexico	Barbados	Austria	Angola	Georgia	Iran		India	Japan	Brunei
United States	Bolivia	Belarus	Cameroon	Kazakhstan	Iraq		Pakistan	Taiwan	Indonesia
	Brazil	Bosnia	Chad	Kyrgyzstan	Israel				Malaysia
	Colombia	Bulgaria	Congo (Brazzaville)	Tajikistan	Jordan				Myanmar
	Cuba	Croatia	Democratic Republic of Congo (Kinshasa)	Turkmenistan	Kuwait				Philippines
	Ecuador	Czech Republic	Egypt	Uzbekistan	Neutral Zone				Thailand
	Guatemala	France	Equatorial Guinea		Oman				Tonga
	Peru	Germany	Gabon		Qatar				Vietnam
	Suriname	Greece	Ghana		Saudi Arabia				
	Trinidad & Tobago	Hungary	Libya		Syria				
	Venezuela	Ireland	Madagascar		Turkey				
		Italy	Morocco		Yemen				
		Malta	Nigeria						
		Moldova	Senegal						
		Netherlands	South Africa						
		Norway	Sudan						
		Poland	Tunsia						
		Romania							
		Serbia							
		Slovakia							
		Spain							
		Sweden							
		Switzerland							
		Ukraine							
		United Kingdom							

Table 7. Attributes of Klemme basin types.

[Sources for attributes 1-15 are Klemme (1980a, 1980b, 1984) and attributes 16 and 17 are from this report]

	Type I	Type IIA	Type IIB	Type IICa
	Craton interior	**Continental multicycle basins, craton margin**	**Continental multicycle basins: craton/acreted zone rift-faulted**	**Continental interior multicycle basins: close collision zone at paleoplate margin**
1. Crustal zone	Continental craton	Continental craton	Contnental craton and accreted zone	Ocean crust early stages then continental crust of craton and accreted zone
2. Tectonic setting	Continenal crust within interior of craton, near or upon Precambrian sheld areas	Continental crust on exterior margin of craton, basins become multicylic ion Paleozoic or Mesozoic when a second cycle of sediments derived from uplife encroaches	Continental crust, or on margin of craton	Convergent margin along collision zone of paleoplates
3. Regional stress	Extensional	1st cycle: extension, 2nd cycle: compression	(1st) extension with rifting, (2nd) extensional sag	(1st) regional extension and platform deposits, then rifting, formation of linear sag, (2nd) compression with creation of foredeep
4. Basin size, shape	Large, circular to elongate	Moderate to large, circular to elongate	Large, circular	Large, elongate
5. Basin profile	Symmetrical	Asymmetrical	Irregular to asymmetrical	Asymmetrical
6. Sediment ratio[1]	Low	High	High	High
7. Architectural sequence	Sag	1st cycle: platform or sag, 2nd cycle: foredeep	(1st) rift, (2nd) large circular sag	(1st) platform or sag, (2nd) foredeep
8. Special features	Unconformities, regional arches, evaporite caps	Large traps, basins and arches, evaporite caps	Large traps, basins and arches, evaporite caps	Large traps and basins, evaporite caps, regional arches, regional source seal, fractured reservoirs
9. Basin lithology[2]	Clastic 60%, carbonate 40%	Clastic 75%, carbonate 25%	Clastic 75%, carbonate 25%	Clastic 35%, carbonate 65%
10. Depth of production[3]	Shallow	Shallow 55%, moderate 25%, deep 5%[5]	Shallow 55%, moderate 25%, deep 5%[5]	Shallow 45%, moderate 30%, deep 25%
11. Geothermal gradient	Low	Low	High	High
12. Temperature	Cool	Cool	Cool	High
13. Age	Paleozoic	Paleozoic, Mesozoic	Paleozoic, Mesozoic	Upper Paleozoic, Mesozoic, Tertiary
14. Oil and gas recovery[4]	Low, few giant fields	Average	Generally average	High
15. Traps	Associated with central arches and stratigraphic traps along basin margins	Basement uplifts, mostly arches or blocks	Basement uplifts, mostly combination of structural stratigraphic	Basement uplifts, arches and fault blocks
16. Propensity for heavy oil	Low	Low	Low	High
17. Propensity for natural bitumen	Low	High	Low	High

[1]Sediment ratio: ratio of sediment volume to basin surface area.

[2]Basin lithology: percentages apply to reservoir rocks, not to the basin fill.

[3]Depth of production: shallow, 0-6000 ft.; medium, 6000-9000 ft.; deep, >9000 ft.

[4]Oil and gas recovery (barrels of oil equivalent per cubic mile of sediment): low, <60,000; average, >=60,000 but <300,000; high, >=300,000.

[5]Does not add to 100% in source, Klemme (1980a,b).

Table 7. Attributes of Klemme basin types.—Continued

	Type IICb	Type IICc	Type IIIA	Type IIIBa
	Continental interior multicycle basins: foredeep portion of collision zone at paleoplate margin	**Continental interior multicycle basins: open collision zone at paleoplate margin**	**Continental rifted basins: craton/accreted zone, rift-faulted, with small linear sag**	**Continental rifted basins: back arc rift-faulted convergent margin**
1. Crustal zone	Ocean crust early stages then continental crust of craton and accreted zone	Ocean crust early stages then continental crust of craton and accreted zone	Continental craton and accreted zone	Contintental accreted zone with oceanic crust in early stages
2. Tectonic setting	Convergent margin along collision zone of paleoplates, but retain only proximal or foredeep portion of original sediment suite	Convergent margin along collision zone of paleoplates	Continental, on margin of craton. About two-thirds of Type IIIA basins form along trend of older deformation; remainder on Precambrian shields	Back arc basins along accreted zone of continent, with continental crust involved in later stages of development and ocean crust in the initial stages
3. Regional stress	(1st) regional extension and platform deposits, then rifting, formation of linear sag, (2nd) compression with creation of foredeep	(1st) regional extension and platform deposits, then rifting, formation of linear sag, (2nd) compression with creation of foredeep	(1st) extension with local wrench faulting during rifting, (2nd) sag	(1st) extension with local wrench faulting compression, (2nd) extension and compression
4. Basin size, shape	Large, elongate	Large, elongate	Small to moderate, fault controlled, elongate	Small, elongate
5. Basin profile	Asymmetrical	Asymmetrical	Irregular	Irregular
6. Sediment ratio[1]	High	High	High	High but variable
7. Architectural sequence	(1st) platform or sag, (2nd) foredeep	(1st) platform or sag, (2nd) foredeep	(1st) extension with local wrench faulting druing rifting, (2nd) sag	Rift faulting leading to linear sag, may be followd by wrench faulting
8. Special features	Large traps and basins, evaporite caps, regional arches, regional source seal, fractured reservoirs	Large traps and basins, evaporite caps, regional arches, regional source seal, fractured reservoirs, unconformities	Large traps, evaporite caps, unconformities, regional source seal	Large traps, and unconformities
9. Basin lithology[2]	Clastic 50%, carbonate 50%	Clastic 35%, carbonate 65%	Clastic 60%, carbonate 40%	Clastic 90%, carbonate 10%
10. Depth of production[3]	Shallow 45%, moderate 30%, deep 25%	Shallow 45%, moderate 30%, deep 25%	Moderate 55%, shallow 30%, deep 15%	Shallow 70%, moderate 20%, deep 10%
11. Geothermal gradient	High	High	High	High
12. Temperature	High	High	Normal to high	Normal to high
13. Age	Upper Paleozoic, Mesozoic, Tertiary	Upper Paleozoic, Mesozoic, Tertiary	Upper Paleozoic, Mesozoic, Paleogene, Neogene	Upper Mesozoic, Paleogene and Neogene
14. Oil and gas recovery[4]	Generally low	High	Generally high	Variable
15. Traps	Basement uplifts, arches and fault blocks	Basement uplifts, arches and fault blocks	Basement uplifts, combination structural/stratigraphic; result in fault block movement	Basement uplifts, fault blocks and combination
16. Propensity for heavy oil	Low	Moderate	Moderate	Low
17. Propensity for natural bitumen	Low	Low	Low	Low

Table 7. Attributes of Klemme basin types.—Continued

	Type IIIBb	Type IIIBc	Type IIIC	Type IV	Type V
	Continental rifted basins: transverse rift-faulted convergent margin	**Continental rifted basins: median rift-faulted convengent margin**	**Continental rifted basins: rift-faulted divergent margin, may be subdivided into (a) parallel, or (b) transverse basins**	**Deltas**	**Fore-arc basins**
1. Crustal zone	Contintental accreted zone with oceanic crust in early stages	Contintental accreted zone with oceanic crust in early stages	Ocean crust in early stage, then continental crust of craton and accreted zone	Ocean crust in early stage, then continental crust of craton and accreted zone	Continetal accreted crust and oceanic crust
2. Tectonic setting	Back arc basins along accreted zone of continent, with continental crust involved in later stages of development and ocean crust in the initial stages	Back arc basins along accreted zone of continent, with continental crust involved in later stages of development and ocean crust in the initial stages	Rift faulting along a divergent, passive or pull-apart continental margin	Almost any location: divergent and convergent margins along open or confined coastal areas	Fore-arc basins located on oceanward side of the volcanic arc in subduction or consumption zone
3. Regional stress	(1st) extension and wrench compression, (2nd) extension and compression	(1st) extension and wrench compression, (2nd) extension and compression	Extension leading to rift or wrench faulting	Extension as sag develops but uncertain as to the initial cause of sag, roots being deeply buried	Compression and extension
4. Basin size, shape	Small, elongate	Small, elongate	Small to moderate, elongate	Moderate, circular to elongate	Small, elongate
5. Basin profile	Irregular	Irregular	Asymmetrical	Depocenter	Asymmetrical
6. Sediment ratio[1]	High but variable	High but variable	High	Extremely high	High
7. Architectural sequence	Rift faulting leading to linear sag, may be followd by wrench faulting	Rift faulting leading to linear sag, may be followd by wrench faulting	Linear sage with irregular profile	Roots of deltas deeply buried; extension leads to half-sag with sedimentary fill thickening seaward.	Small linear troughs
8. Special features	Large traps, and unconformities	Large traps, unconformities, and regional arches	Possible unconformities and regional source seals	None	Large traps, and unconformities
9. Basin lithology[2]	Clastic 90%, carbonate 10%	Clastic 90%, carbonate 10%	Clastic 70%, carbonate 30%	Clastic 100%	Clastic 90%, carbonate 10%
10. Depth of production[3]	Shallow 70%, moderate 20%, deep 10%	Shallow 70%, moderate 20%, deep 10%	Deep 60%, moderate 30%, shallow 10%	Deep 65%, moderate 30%, shallow 5%	Shallow 70%, deep 20%, moderate 10%
11. Geothermal gradient	High	Normal to high	Low	Low	High
12. Temperature	Normal to high	Normal to high	Cool	Normal to low	High to normal
13. Age	Upper Mesozoic, Paleogene and Neogene	Upper Mesozoic, Paleogene and Neogene	Upper Mesozoic, Paleogene and Neogene	Paleogene, Neogene, and Quaternary	Upper Mesozoic, Tertiary
14. Oil and gas recovery[4]	Variable	Variable	Low	High	High but variable
15. Traps	Basement uplifts, fault blocks and combination	Basement uplifts, fault blocks and combination	Fault blocks and combination	Primarily tensional growth (roll-over) anticlines and flowage: basement not involved	Fault blocks and combination
16. Propensity for heavy oil	Low	Moderate	Low	Low	Nil
17. Propensity for natural bitumen	Low	Low	Low	Nil	Nil

Table 8. Regional distribution of heavy oil and natural bitumen (billion barrels).

[Volumes may not add to totals due to independent rounding]

Region[1]	Discovered orginal oil in place	Prospective additional	Total original oil in place
		Heavy oil	
North America……	650	2	651
South America……	1099	28	1127
Europe…….	75	0	75
Africa……..	83	0	83
Transcaucasia……..	52	0	52
Middle East…….	971	0	971
Russia……..	182	0	182
South Asia……...	18	0	18
East Asia…….	168	0	168
Southeast Asia and Oceania……	68	0	68
Total……..	3366	29	3396
		Natural bitumen	
North America……	1671	720	2391
South America……	2070	190	2260
Europe…….	17	0	17
Africa……..	13	33	46
Transcaucasia……..	430	0	430
Middle East…….	0	0	0
Russia……..	296	51	347
South Asia……...	0	0	0
East Asia…….	10	0	10
Southeast Asia and Oceania……	4	0	4
Total……..	4512	993	5505

[1] See table 6 for a list of countries reporting deposits of heavy oil and/or natural bitumen grouped by regions.

Appendixes 1–4

Appendix 1. Map Basin Name Conventions

Table 1-1. List of geologic provinces where province names used in this report differ from names used in St. John, Bally and Klemme (1984).

Geological province name in this report	Geological province name in St. John, Bally, and Klemme (1984)
Amu Darya	Tadzhik
Arkla	Louisiana Salt Dome
Baikal	Lake Baikal
Barinas-Apure	Llanos de Casanare
Carnarvon	Dampier
Central Montana Uplift	Crazy Mountains
Central Sumatra	Sumatra, Central
East Java	Java, East
East Texas	East Texas Salt Dome
Eastern Venezuela	Maturin
Forest City	Salina-Forest City
Gulf of Alaska	Alaska, Gulf of
Gulf of Suez	Suez, Gulf of
Guyana	Guiana
Junggar	Zhungeer
Kutei	Mahakam
Mae Fang	Fang
Minusinsk	Minisinsk
North Caspian	Caspian, North
North Caucasus-Mangyshlak	Caucasus, North
North Egypt	Western Desert
North Sakhalin	Sakhalin, North
North Sumatra	Sumatra, North
North Ustyurt	Ust Urt
Northern North Sea	North Sea, Northern
Northwest Argentina	Argentina, Northwest
Northwest German	German, Northwest
Northwest Shelf	Dampier
Ordos	Shanganning
Progreso	Guayaquil
Sacramento	Sacramento/San Joaquin
Salinas	Salinas (Mexico)
San Joaquin	Sacramento/San Joaquin
South Adriatic	Adriatic, South
South Palawan	Palawan, South
South Sumatra	Sumatra, South
Timan-Pechora	Pechora
Turpan	Tulufan

Table 1-1. List of geologic provinces where province names used in this report differ from names used in St. John, Bally and Klemme (1984).—Continued

Geological province name in this report	Geological province name in St. John, Bally, and Klemme (1984)
Upper Magdalena	Magdalena, Upper
West Java	Java, West, Sunda
West of Shetlands	Shetlands, West
Western Canada Sedimentary	Alberta
Yukon-Kandik	Yukon/Kandik

The following basins listed in bold type are from the digital mapping file of St. John (1996) and require further explanation:

- **Anadarko**: includes provinces more commonly known as the *Anadarko,* Central Kansas Uplift, Chautauqua Platform, *Las Animas Arch,* Nemaha Anticline-Cherokee Basin, *Ozark Uplift,* Sedgwick, and South Oklahoma Folded Belt (provinces in italics report neither heavy oil nor natural bitumen.)
- **Sacramento/San Joaquin**: separated into two distinct provinces, Sacramento and San Joaquin.
- **North Sea, Southern**: : includes both the Anglo-Dutch and Southern North Sea basins.
- **South Adriatic**: includes both the Durres and South Adriatic basins.

Other comments:

Three separate outlines for Marathon, Ouachita, and Eastern Overthrust are shown as a common province Marathon/Ouachita/Eastern Overthrust in the original St John (1996) but only Ouachita Basin had reported volumes of natural bitumen resources.

Deposits reported for Eastern Venezuela basin include deposits on the island of Trinidad, which are a likely extension of the rock formations from the surface expression of the basin outline.

The plates attach the name of Barinas Apure to the polygonal province labeled Llanos de Casanare in St. John (1996). Barinas Apure is the province name commonly used in Venezuela and Llanos de Casanare is the province name commonly used in Colombia for the same geologic province.

Appendix 2. Basins, Basin Type and Location of Basins having Heavy Oil and Natural Bitumen Deposits

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.

Geological province	Klemme basin type	Country	State/Province	Other names
Aegian	IIIBc	Greece		North Aegean Trough (North Aegean Sea Basin)
Akita	IIIBa	Japan		Akita Basin, Japan Accreted Arc/Accreted Terrane
Amu-Darya	IICa	Tajikistan, Uzbekistan		Tadzhik, Surkhan-Vaksh, Badkhyz High (Murgab Basin), Afghan-Tajik
Amur	IIIBc	Georgia		
Ana Maria	IIIBb	Cuba		Zaza Basin, Greater Antilles Deformed Belt
Anabar-Lena	IIA	Russia		
Anadarko	IIA	United States	Kans.	
Anadyr	IIIBb	Russia		
Angara-Lena	IIA	Russia		
Anglo-Dutch	IIB	Netherlands		Central Graben, North Sea, Southern
Appalachian	IIA	United States	Ky., N.Y.	
Aquitaine	IIIA	France		Ales, Aquitaine, Lac Basin, Parentis, Massif Central, Pyrenean Foothills-Ebro Basin
Arabian	IICa	Bahrain, Iran, Iraq, Jordan, Kuwait, Neutral Zone, Oman, Qatar, Saudi Arabia, Syria		Arabian Basin, Rub Al Khali, Aneh Graben, Aljafr Sub-basin, Oman Platform, Mesopotamian Foredeep, Palmyra Zone, Oman Sub-Basin, Euphrates/Mardin, Ghaba Salt Basin, Greater Ghawar Uplift, Haleb, Qatar Arch, South Oman Salt Basin, Widyan Basin
Arkla	IICc	United States	Ark., La.	Louisiana Salt Dome
Arkoma	IIA	United States	Ark., Okla.	
Assam	IICb	India		
Atlas	IICb	Algeria		Moroccan-Algerian-Tunisian Atlas, Hodna-Constantine
Bahia Sul	IIIC	Brazil		J Equitinhonha
Baikal	IIIA	Russia		Lake Baikal
Balearic	IIIA	Spain		Western Mediterranean, Gulf of Valencia, Barcelona Trough (Catalano-Balearic Basin), Iberic Cordillera
Baltic	I	Sweden		
Baluchistan	IICb	Pakistan		Sulaiman-Kirthar
Barbados	V	Barbados		Lesser Antilles, Northeast Caribbean Deformed Belt
Barinas-Apure	IIA	Venezuela, Colombia		Barinas-Apure Basin, Llanos de Casanare
Barito	IIIBa	Indonesia		Barito Basin
Bawean	IIIBa	Indonesia		
Beibu Gulf	IIIBa	China		Beibuwan (Gulf of Tonkin) Basin
Bengal	IICa	Bangladesh, India		Bengal (Surma Sub-basin), Tripura-Cachar, Barisal High (Bengal Basin), Ganges-Brahmaputra Delta
Beni	IIA	Bolivia		Foothill Belt
Big Horn	IIA	United States	Mont., Wyo.	
Black Mesa	IIB	United States	Ariz.	Dry Mesa, Dineh Bi Keyah
Black Warrior	IIA	United States	Ala., Miss.	
Bohai Gulf	IIIA	China		Bohai Wan (Huabei-Bohai) Basin, Huabei, Pohal, Luxi Jiaoliao Uplift

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Bombay	IIIC	India		
Bonaparte Gulf	IIIC	Australia		Berkeley Platform (Bonaparte Basin)
Bone Gulf	IIIBa	Indonesia		Bone
Bresse	IIIA	France		Jura Foldbelt
Browse	IIIC	Australia		
Brunei-Sabah	IICc	Brunei, Malaysia		Baram Delta
Cabinda	IIIC	Angola, Congo (Brazzaville), Democratic Republic of Congo (Kinshasa)		Lower Congo Basin, West-Central Coastal
Caltanisetta	IICb	Italy, Malta		Caltanissetta Basin, Ibleian Platform, Sicilian Depression
Cambay	IIIA	India		Cambay North, Bikaner-Nagam, Bombay (in part)
Campeche	IICc	Mexico		Tabasco-Campeche, Yucatan Boderland and Platform, Tobasco, Campeche-Sigsbee Salt, Villahermosa Uplift
Campos	IIIC	Brazil		Cabo Frio High (Campos Basin)
Cantabrian	IIIA	Spain		Offshore Cantabrian Foldbelt (Cantabrian Zone), Spanish Trough-Cantabrian Zone
Carnarvon	IIIC	Australia		Dampier, Northwest Shelf, Carnarvon Offshore, Barrow-Dampier Sub-Basin
Carpathian	IICb	Austria, Czech Republic, Poland, Ukraine		Carpathian Flysch, Carpathian Foredeep, Bohemia, Carpathian-Balkanian
Celtic	IIIA	Ireland		Celtic Sea Graben System, Ireland-Scotland Platform
Central Coastal	IIIBb	United States	Calif.	Coastal, Santa Cruz, Salinas Valley, Northern Coast Range
Central Kansas Uplift	IIA	United States	Kans.	Anadarko
Central Montana Uplift	IIA	United States	Mont.	Crazy Mountains
Central Sumatra	IIIBa	Indonesia		Central Sumatra Basin
Ceram	IICa	Indonesia		North Seram Basin, Banda Arc
Channel Islands	IIIBb	United States		Southern California Borderlands
Chao Phraya	IIIA	Thailand		Phitsanulok Basin, Thailand Mesozoic Basin Belt
Chautauqua Platform	IIA	United States	Okla.	Anadarko
Cincinnati Arch	I	United States	Ky., Ohio	
Cook Inlet	IIIBa	United States	Alaska	Susitna Lowlands
Cuanza	IIIC	Angola		Kwanza Basin, West-Central Coastal
Cuyo	IIB	Argentina		Alvear Sub-basin (Cuyo Basin), Cuyo-Atuel
Dead Sea	IICa	Israel, Jordan		Syrian -African Arc, Levantine, Jafr-Tabuk, Sinai
Denver	I	United States	Colo., Nebr.	Denver-Julesberg
Diyarbakir	IICa	Syria, Turkey		Bozova-Mardin High (Southeast Turkey Fold Belt), Euphrates/Mardin, Zagros Fold Belt
Dnieper-Donets	IIIA	Ukraine		Dnepr-Donets Graben
Doba	IIIA	Chad		
Durres	IICb	Albania		Ionian Basin (zone), South Adriatic, Pre-Adriatic
East China	IIIBa	China, Taiwan		Diaoyu Island Depression (East China Sea Basin)
East Java	IIIBa	Indonesia		Bawean Arch (East Java Basin)
East Texas	IICc	United States	Tex.	East Texas Salt Dome, Ouachita Fold Belt
Eastern Venezuela	IICa	Venezuela, Trinidad and Tobago		Maturin, Eastern Venezuela Basin, Orinoco Oil Belt, Guarico Sub-basin, Trinidad-Tabago

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Espirito-Santo	IIIC	Brazil		Abrolhos Bank Sub-Basin (Espirito Santo Basin)
Fergana	IIIBc	Kyrgyzstan, Tajikistan, Uzbekistan		
Florida-Bahama	IIIC	Cuba, United States	Fla.	Almendares-San Juan Zone, Bahia Honda Zone, Llasvvillas Zone, Florida Platform, Greater Antilles Deformed Belt
Forest City	I	United States	Kans., Nebr.	Salina-Forest City, Salina, Chadron Arch
Fort Worth	IIA	United States	Tex.	Bend Arch, Fort Worth Syncline, Llano Uplift, Ouachita Overthrust
Gabon	IIIC	Gabon		Gabon Coastal Basin (Ogooue Delta), West-Central Coastal
Gaziantep	IICa	Syria, Turkey		
Ghana	IIIC	Ghana, Nigeria		Benin-Dahomey, Dahomey Coastal
Gippsland	IIIA	Australia		Gippsland Basin
Green River	IIA	United States	Colo., Wyo.	
Guangxi-Guizou	IIB	China		Bose (Baise) Basin, South China Fold Belt
Gulf Coast	IICc	United States	La., Tex.	Mid-Gulf Coast, Ouachita Folded Belt, Burgos
Gulf of Alaska	V	United States	Alaska	
Gulf of Suez	IIIA	Egypt		Gulf of Suez Basin, Red Sea Basin
Guyana	IIIC	Suriname		Guiana, Bakhuis Horst, Guyana-Suriname
Illinois	I	United States	Ill., Ky.	
Indus	IICb	India		Punjab (Bikaner-Nagaur Sub-basin), West Rajasthan
Ionian	IICb	Greece		Epirus, Peloponesus
Irkutsk	IIA	Russia		
Jeanne d'Arc	IIIC	Canada	N.L.	Labrador-Newfoundland Shelf
Jianghan	IIIA	China		Tung-T'Ing Hu
Junggar	IIIA	China		Zhungeer, Anjihai-Qigu-Yaomashan Anticlinal Zone (Junggar)
Kansk	IIA	Russia		
Krishna	IIIC	India		Krishna-Godavari Basin
Kura	IIIBc	Azerbaijan, Georgia		Kura Basin
Kutei	IIIBa	Indonesia		Mahakam
Kuznets	IIB	Russia		
Laptev	IIB	Russia		
Los Angeles	IIIBb	United States	Calif.	
MacKenzie	IV	Canada	N.W.T.	Beaufort Sea, MacKenzie Delta
Mae Fang	IIIA	Thailand		Fang, Mae Fang Basin, Tenasserim-Shan
Maracaibo	IIIBc	Venezuela, Colombia		Maracaibo Basin, Catatumbo
Mauritius-Seychelles	IIIC	Seychelles		
Mekong	IIIC	Vietnam		Mekong Delta Basin
Michigan	I	United States	Mich.	
Middle Magdalena	IIIBc	Colombia		Middle Magdalena Basin
Minusinsk	IIB	Russia		Minisinsk
Mississippi Salt Dome	IICc	United States	Ala., Miss.	
Moesian	IICb	Bulgaria, Moldova, Romania		Moesian Platform-Lom Basin, Alexandria Rosiori Depression (Moesian Platform), Carpathian-Balkanian, West Black Sea

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Molasse	IICb	Austria, Germany, Italy, Switzerland		Molasse Basin
Morondava	IIIC	Madagascar		
Mukalla	IIIC	Yemen		Sayhut Basin, Masila-Jeza
Natuna	IIIA	Indonesia		
Nemaha Anticline-Cherokee Basin	IIA	United States	Kans., Mo.	Anadarko
Neuquen	IIB	Argentina		Agrio Fold Belt (Neuquen Basin)
Niger Delta	IV	Cameroon, Equatorial Guinea, Nigeria		Abakaliki Uplift (Niger Delta)
Niigata	IIIBa	Japan		Niigata Basin, Yamagata Basin, Japan Volcanic Arc/Accreted Terrane
Nile Delta	IV	Egypt		Nile Delta Basin
North Caspian	IICa	Kazakhstan, Russia		Akatol' Uplift, Alim Basin, Beke-Bashkuduk Swell Pri-Caspian, Kobyskol' Uplift, South Emba, Tyub-Karagan
North Caucasus-Mangyshlak	IICa	Russia		Indolo-Kuban-Azov-Terek-Kuma Sub-basins, North Buzachi Arch, Middle Caspian, North Caucasus
North Egypt	IICa	Egypt		Western Desert, Abu Gharadiq
North Sakhalin	IIIBb	Russia		Sakhalin North
North Slope	IICc	United States	Alaska	Arctic Coastal Plains, Interior Lowlands, Northern Foothills, Southern Foothills, Colville
North Sumatra	IIIBa	Indonesia		North Sumatra Basin
North Ustyurt	IIB	Kazakhstan		Ust-Urt
Northern North Sea	IIIA	Norway, United Kingdom		Viking Graben, North Sea Graben
Northwest Argentina	IIA	Argentina		Carandaitycretaceous Basin
Northwest German	IIB	Germany		Jura Trough, West Holstein
Olenek	I	Russia		
Ordos	IIA	China		Shanganning, Qinling Dabieshan Fold Belt
Oriente	IIA	Peru		Acre, Maranon, Upper Amazon
Otway	IIIC	Australia		
Ouachita Overthrust	IIA	United States	Ark.	
Palo Duro	IIA	United States	N. Mex.	Tucumcari
Pannonian	IIIBc	Bosnia and Herzegovina, Croatia, Hungary, Romania, Serbia		Backa Sub-basin (Pannonian Basin)
Paradox	IIB	United States	Utah	
Paris	IIB	France		Anglo-Paris Basin
Pearl River	IIIC	China		Dongsha Uplift (Pearl River Basin), Pearl River Mouth, South China Continental Slope
Pelagian	IICa	Tunisia, Libya		
Permian	IIA	United States	N. Mex., Tex.	Ouachita Fold Belt, Bend Arch, Delaware, Midland
Peten-Chiapas	IICc	Guatemala		Chapayal (South Peten) Basin, North Peten (Paso Caballos), Sierra De Chiapas-Peten, Yucatan Platform
Piceance	IIA	United States	Colo.	
Po	IICb	Italy		Crema Sub-Basin (Po Basin)
Polish	IIIA	Poland		Danish-Polish Marginal Trough, German-Polish

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Potiguar	IIIC	Brazil		Boa Vista Graben (Potiguar Basin), North-Northeastern Region
Potwar	IICb	Pakistan		Bannu Trough (Potwar Basin), Kohat-Potwar
Powder River	IIA	United States	Mont., Wyo.	
Pripyat	IIIA	Belarus		Pripyat Graben
Progreso	IIIBb	Ecuador		Guayaquil, Gulf Of Gayaquil, Jambeli Sub-basin of Progresso Basin, Santa Elena
Putumayo	IIA	Colombia, Ecuador		Napo, Cuenca Oriente Ecuatoriana
Rhine	IIIA	France, Germany		Upper Rhine Graben
Sacramento	IIIBb	United States	Calif.	Sacramento-San Joaquin
Salawati	IICa	Indonesia		Salawati Basin, Bintuni-Salawati
Salinas	IICc	Mexico		Isthmus Of Tehuantepec, Salinas Sub-basin, Isthmus Saline, Saline Comalcalco
San Joaquin	IIIBb	United States	Calif.	Sacramento-San Joaquin
San Jorge	IIIA	Argentina		Rio Mayo, San Jorge Basin
San Juan	IIB	United States	Ariz., Colo., N. Mex.	
Santa Maria	IIIBb	United States	Calif.	
Santos	IIIC	Brazil		
Sarawak	IICc	Malaysia		Central Luconia Platform
Sedgwick	IIA	United States	Kans.	Anadarko
Senegal	IIIC	Senegal		Bove-Senegal Basins
Sergipe-Alagoas	IIIC	Brazil		Sergipe-Alagoas Basin
Shumagin	V	United States	Alaska	
Sirte	IIIA	Libya		Agedabia Trough (Sirte Basin)
Songliao	IIIA	China		
South Adriatic	IICb	Italy		Adriatic, Marche-Abruzzi Basin (Pede-Apenninic Trough), Plio-Pleist Foredeep, Scaglia
South African	IIIC	South Africa		Agulhas Arch (South African Coastal Basin)
South Burma	IIIBb	Burma		Central Burma Basin, Irrawaddy
South Caspian	IIIBc	Azerbaidjan		South Caspian OGP (Apsheron-Kobystan Region), Emba, Guriy Region
South Oklahoma Folded Belt	IIA	United States	Okla., Tex.	Anadarko
South Palawan	IIIBa	Philippines		China Sea Platform, Palawan Shelf
South Sumatra	IIIBa	Indonesia		Central Palembang Depression (South Sumatra Basin)
South Texas Salt Dome	IICc	United States	Tex.	
South Yellow Sea	IIIA	China		Central Uplift (South Huanghai Basin), Subei Yellow Sea
Southern North Sea	IIB	United Kingdom		Central Graben (North Sea Graben system), Dutsh Bank Basin (East Shetland Platform), Witch Ground Graben
Sudan	IIIA	Sudan		Kosti Sub-Basin (Melut Basin), Muglad Basin, Sudd Basin
Sunda	IIIBa	Indonesia		
Surat	IIB	Australia		
Sverdrup	IICc	Canada	N.W.T.	Mellville
Taiwan	IIIBa	Taiwan		Taihsi Basin

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Talara	IIIBb	Peru		Talara Basin
Tampico	IICc	Mexico		Tampico-Tuxpan Embayment, Chicontepec, Tampico-Misantla
Tarakan	IIIBa	Indonesia		Bera Sub-basin (Tarakan Basin), Pamusian-Tarakan
Taranto	IICb	Italy		Abruzzi Zone (Apennine Range). Marche-Abruzzi Basin (Pede-Apenninic Trough), Latium, Calabrian
Tarfaya	IIIC	Morocco		Aaiun-Tarfaya
Tarim	IIIA	China		
Thrace	IIIBc	Turkey		Thrace-Gallipoli Basin, Zagros Fold Belt
Timan-Pechora	IIB	Russia		Belaya Depression (Ural Foredeep), Brykalan Depression, Pechora-Kozhva Mega-Arch, Varendey-Adz'va
Timimoun	IIB	Algeria		Sbaa
Tonga	IIIBa	Tonga		
Tunguska	I	Russia		Baykit Antecline
Turpan	IIIA	China		Tulufan
Tyrrhenian	IIIA	Italy		
Uinta	IIA	United States	Utah	
Upper Magdalena	IIIBc	Colombia		Upper Magdalena Basin
Ventura	IIIBb	United States	Calif.	Santa Barbara Channel
Veracruz	IIIC	Mexico		
Verkhoyansk	IIA	Russia		
Vienna	IIIBc	Austria, Slovakia		Bohemia
Vilyuy	IIA	Russia		
Volga-Ural	IIA	Russia		Aksubayevo-Nurlaty Structural Zone, Bashkir Arch, Belaya Depression, Melekess Basin, Tatar Arch, Vishnevo-Polyana Terrace
Washakie	IIA	United States	Wyo.	
West Java	IIIBa	Indonesia		Arjuna Sub-Basin (West Java Basin), Northwest Java
West of Shetlands	IIIC	United Kingdom		Faeroe, West of Shetland
West Siberia	IIB	Russia		West Siberia
Western Canada Sedimentary	IIA	Canada, United States	Alta., Mont., Sask.	Alberta, Western Canada Sedimentary, Sweetgrass Arch
Western Overthrust	IIA	United States	Ariz., Mont., Nev., Utah	Central Western Overthrust, Great Basin Province, Southwest Wyoming, South Western Overthrust
Williston	I	Canada, United States	N. Dak., Sask.	Sioux Uplift
Wind River	IIA	United States	Wyo.	
Yari	IIA	Colombia		Yari Basin
Yenisey-Khatanga	IIA	Russia		
Yukon-Kandik	IIIBb	United States	Alaska	Yukon-Koyukuk
Zagros	IICa	Iran, Iraq		Zagros Fold Beltzagros or Iranian Fold Belt, Sinjar Trough, Bozova-Mardin High, Euphrates/Mardin

Appendix 3. Klemme Basin Classificaton Figure from Plate 1

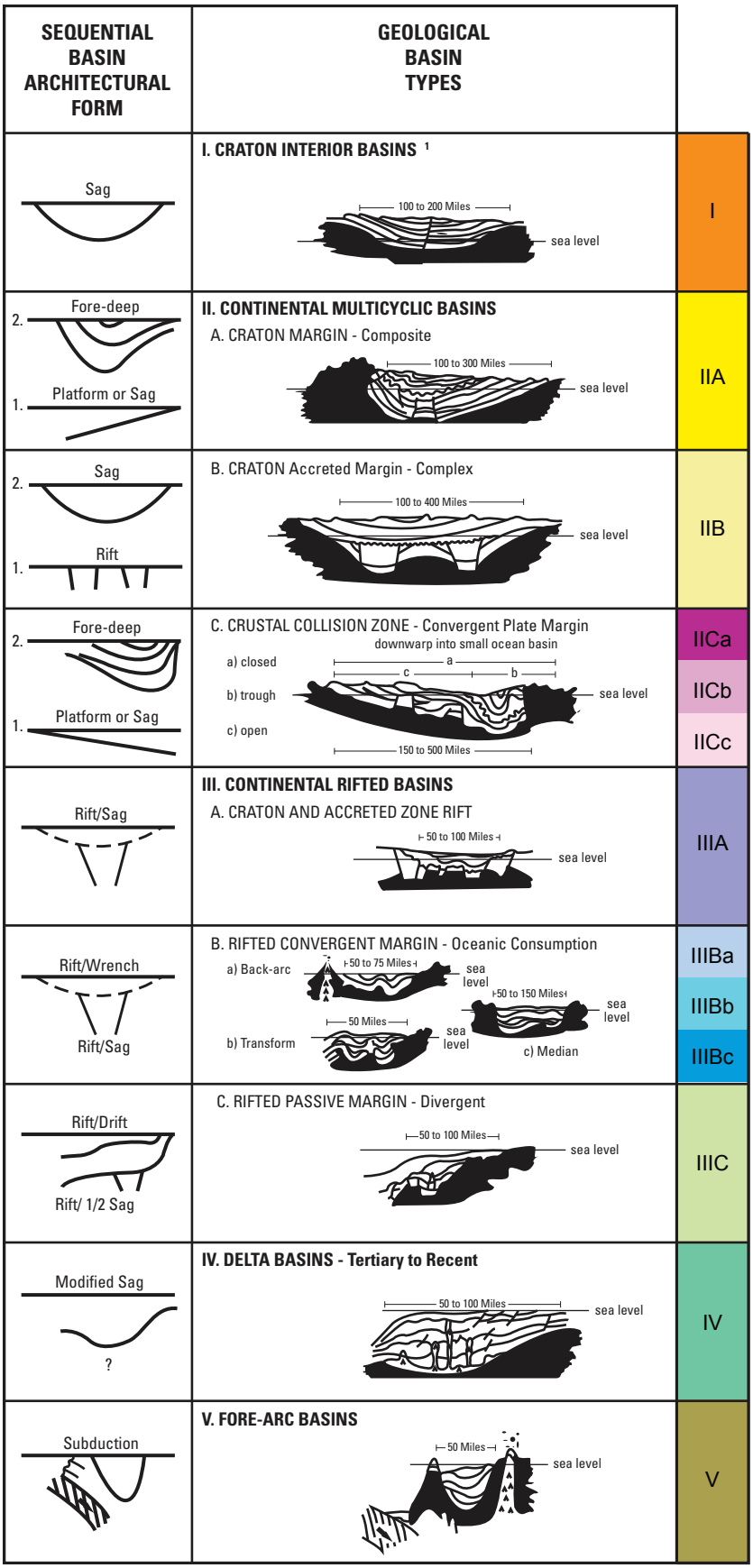

Figure 2-1. Diagram of Klemme basin types from plate 1. Modified from St. John, Bally, and Klemme (1984).
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[1] Cincinati Arch is classified as I-Arch

Appendix 4. Tables from the Plates

Table 4-1. 50 heavy oil basins ranked by volumes of total original heavy oil in place (TOHOIP), showing natural bitumen volumes where reported. Table repeated from plate 2.

[billions of barrels, BBO, 10^9 barrels]

Rank	Geological province	Klemme basin type	Total original heavy oil in place	Original heavy oil in place-discovered	Prospective additional heavy oil in place	Total original natural bitumen in place	Original natural bitumen in place-discovered	Prospective additional natural bitumen in place
1	Arabian	IICa	842	842				
2	Eastern Venezuela	IICa	593	566	27.7	2,090	1,900	190
3	Maracaibo	IIIBc	322	322		169	169	
4	Campeche	IICc	293	293		0.060	0.060	
5	Bohai Gulf	IIIA	141	141		7.63	7.63	
6	Zagros	IICa	115	115				
7	Campos	IIIC	105	105				
8	West Siberia	IIB	88.4	88.4				
9	Tampico	IICc	65.3	65.3				
10	Western Canada Sedimentary	IIA	54.9	54.9		2,330	1,630	703
11	Timan-Pechora	IIB	54.9	54.9		22.0	22.0	
12	San Joaquin	IIIBb	53.9	53.9		< 0.01	< 0.01	
13	Putumayo	IIA	42.4	42.4		0.919	0.919	
14	Central Sumatra	IIIBa	40.6	40.6				
15	North Slope	IICc	37.0	37.0		19.0	19.0	
16	Niger Delta	IV	36.1	36.1				
17	Los Angeles	IIIBb	33.4	33.4		< 0.01	< 0.01	< 0.01
18	North Caspian	IICa	31.9	31.9		421	421	
19	Volga-Ural	IIA	26.1	26.1		263	263	
20	Ventura	IIIBb	25.2	25.2		0.505	0.505	
21	Gulf of Suez	IIIA	24.7	24.7		0.500	0.500	
22	Northern North Sea	IIIA	22.8	22.8		10.9	10.9	
23	Gulf Coast	IICc	19.7	19.7				
24	Salinas	IICc	16.6	16.6				
25	Middle Magdalena	IIIBc	16.4	16.4				
26	Pearl River	IIIC	15.7	15.7				
27	North Ustyurt	IIB	15.0	15.0				
28	Brunei-Sabah	IICc	14.7	14.7				
29	Diyarbakir	IICa	13.5	13.5				

Table 4-1. 50 heavy oil basins ranked by volumes of total original heavy oil in place (TOHOIP), showing natural bitumen volumes where reported. Table repeated from plate 2.—Continued

[billions of barrels, BBO, 10^9 barrels]

Rank	Geological province	Klemme basin type	Total original heavy oil in place	Original heavy oil in place-discovered	Prospective additional heavy oil in place	Total original natural bitumen in place	Original natural bitumen in place-discovered	Prospective additional natural bitumen in place
30	Northwest German	IIB	9.48	9.48				
31	Barinas-Apure	IIA	9.19	9.19		0.38	0.38	
32	North Caucasus-Mangyshlak	IICa	8.60	8.60		0.060	0.060	
33	Cambay	IIIA	8.28	8.28				
34	Santa Maria	IIIBb	8.06	8.06		2.03	2.02	< 0.01
35	Central Coastal	IIIBb	8.01	8.01		0.095	0.025	0.070
36	Big Horn	IIA	7.78	7.78				
37	Arkla	IICc	7.67	7.67				
38	Moesian	IICb	7.39	7.39				
39	Assam	IICb	6.16	6.16				
40	Oriente	IIA	5.92	5.92		0.250	0.250	
41	Molasse	IICb	5.79	5.79		0.010	0.010	
42	Doba	IIIA	5.35	5.35				
43	Morondava	IIIC	4.75	4.75		2.21	2.21	
44	Florida-Bahama	IIIC	4.75	4.75		0.48	0.48	
45	Southern North Sea	IIB	4.71	4.71				
46	Durres	IICb	4.70	4.70		0.37	0.37	
47	Caltanisetta	IICb	4.65	4.65		4.03	4.03	
48	Neuquen	IIB	4.56	4.56				
49	North Sakhalin	IIIBb	4.46	4.46		< 0.01	< 0.01	
50	Cabinda	IIIC	4.43	4.43		0.363	0.363	

Table 4-2. 33 natural bitumen basins ranked by volumes of total original natural bitumen in place (TONBIP). Table repeated from plate 3.

[billions of barrels, BBO, 10^9 barrels]

Rank	Geological province	Klemme basin type	Total original natural bitumen in place	Original natural bitumen in place-discovered	Prospective additional natural bitumen in place
1	Western Canada Sedimentary	IIA	2,330	1,630	703
2	Eastern Venezuela	IICa	2,090	1,900	190
3	North Caspian	IICa	421	421	
4	Volga-Ural	IIA	263	263	
5	Maracaibo	IIIBc	169	169	
6	Tunguska	I	59.5	8.19	51.3
7	Ghana	IIIC	38.3	5.74	32.6
8	Timan-Pechora	IIB	22.0	22.0	
9	North Slope	IICc	19..0	19.0	
10	Uinta	IIA	11.7	7.08	4.58
11	Northern North Sea	IIIA	10.9	10.9	
12	South Caspian	IIIBc	8.84	8.84	
13	Bohai Gulf	IIIA	7.63	7.63	
14	Paradox	IIB	6.62	4.26	2.36
15	Black Warrior	IIA	6.36	1.76	
16	South Texas Salt Dome	IICc	4.88	3.87	1.01
17	Cuanza	IIIC	4.65	4.65	
18	Bone Gulf	IIIBa	4.46	4.46	
19	Caltanisetta	IICb	4.03	4.03	
20	Nemaha Anticline-Cherokee Basin	IIA	2.95	0.70	2.25
21	Morondava	IIIC	2.21	2.21	
22	Yenisey-Khatanga	IIA	2.21	2.21	
23	Santa Maria	IIIBb	2.03	2.02	<0.01
24	Junggar	IIIA	1.59	1.59	
25	Tarim	IIIA	1.25	1.25	
26	West of Shetlands	IIIC	1.00	1.00	
27	Putumayo	IIA	0.919	0.919	
28	Illinois	I	0.890	0.300	0.590
29	South Oklahoma Folded Belt	IIA	0.885	0.058	0.827
30	South Adriatic	IICb	0.510	0.510	
31	Ventura	IIIBb	0.505	0.505	
32	Gulf of Suez	IIIA	0.500	0.500	
33	Florida-Bahama	IIIC	0.477	0.477	

Attachment KR–2

Karras, 2010. Combustion emissions from refining lower quality oil: What is the global warming potential? *Env. Sci. Technol.* 44(24). DOI: 10.1021/es1019965. (Incorporated by reference in CBE supp. technical comments of 15 Sep 2014.)

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

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

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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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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

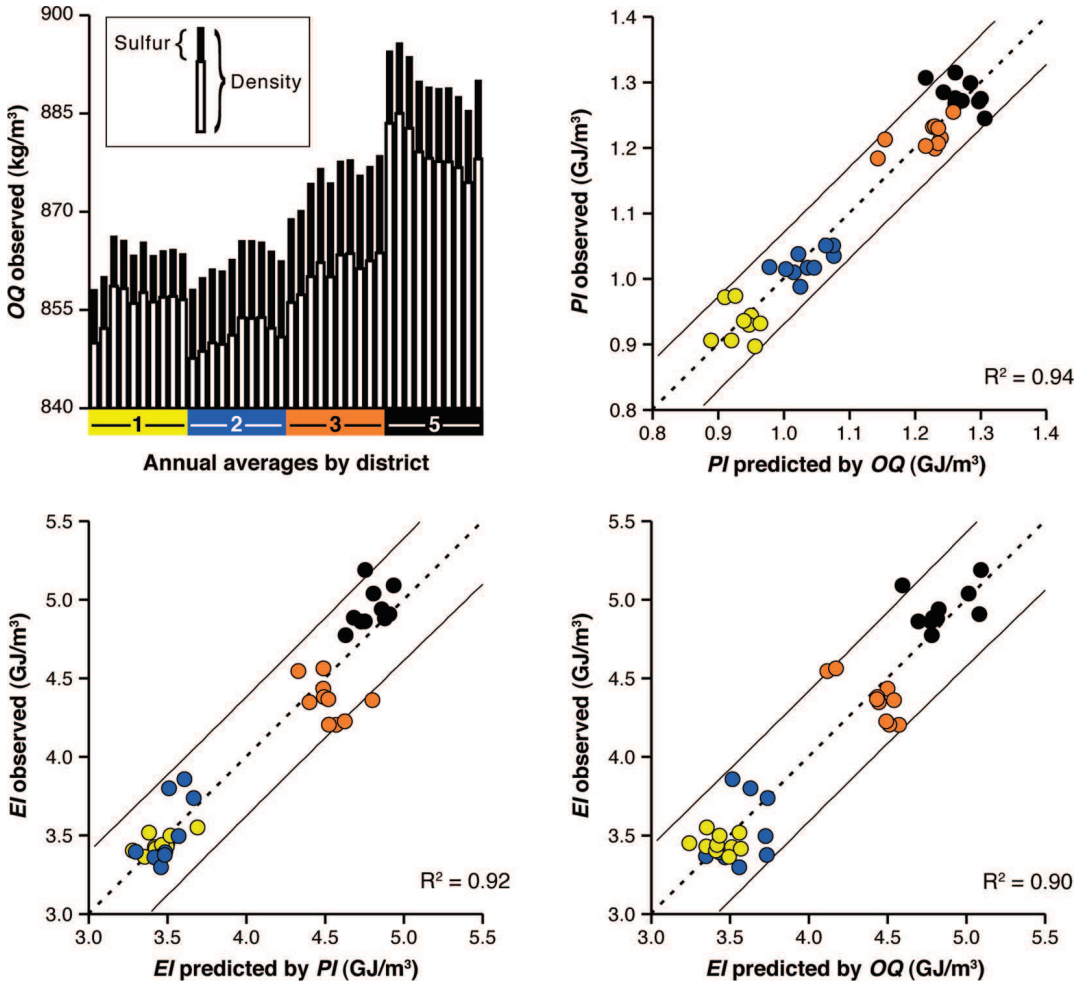

FIGURE 1. Increasing crude processing intensity and energy intensity with worsening oil quality. *OQ:* Crude feed oil quality. *PI:* Crude processing intensity. *EI:* Refinery energy intensity. Observations are annual weighted averages for districts 1 (yellow), 2 (blue), 3 (orange), and 5 (black) in 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			lubricants		0.04
	0.18		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

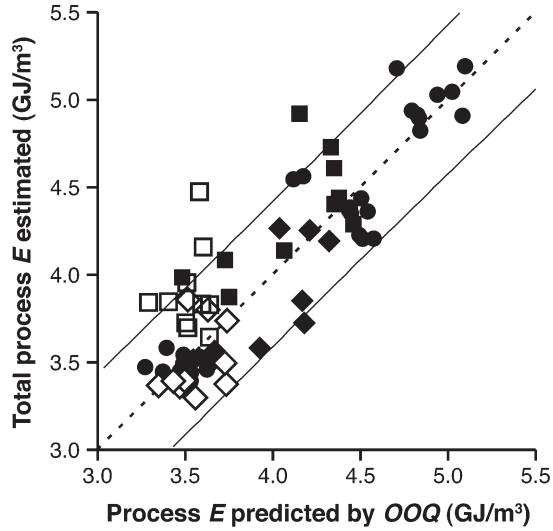

FIGURE 2. Estimated process energy for bitumen upgrading and refining versus that predicted by oil quality (GJ/m^3 crude), 1999−2008. *OOQ:* original oil quality including bitumen quality for synthetic oil inputs. Black diamonds: District 2. Black squares: District 4. Black circles: Districts 1, 3, and 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.

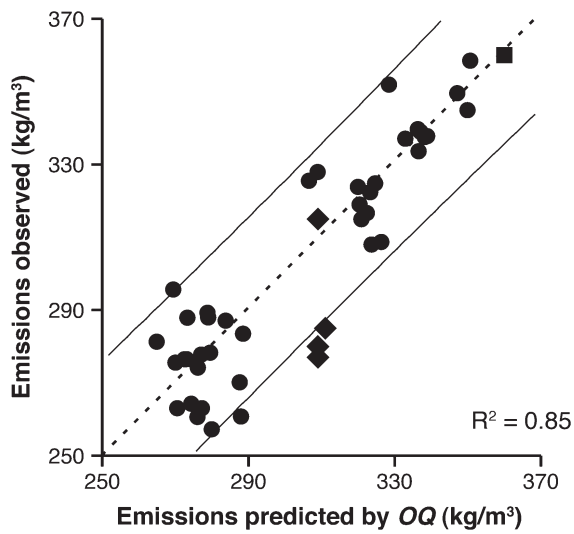

FIGURE 3. Refinery CO_2 emission intensity observed versus predicted by oil quality. *OQ:* Oil quality. Black circles: District 1, 2, 3, or 5 annually, 1999−2008. Black diamonds: United States in 2002, 2005, 2006, 2007. Black square: San Francisco Bay Area in 2008. Diagonal lines bound the 95% confidence 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.

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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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Supporting information for the manuscript:

Combustion emissions from refining lower quality oil: What is the global warming potential?

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Supporting information given in the following 49 pages includes tables S1–S9, Figure S1, and references. Each table includes a legend and notes narrative that follows the values given, as does the figure. References identify sources of data cited. This information appears as follows:

Pages S2-14: **Table S1.** Data.

Pages S15-19: **Table S2.** Simplified mixing analysis for potential effects of anomalous oils on crude feeds.

Pages S20-23: **Table S3.** Estimate calculation for Canadian synthetic crude oil (SCO) exports to districts and years.

Pages S24-26: **Table S4.** Evidence for effects of synthetic oil (SCO) on refinery processing during 1999-2008 in District 4.

Page S27: **Table S5.** Efficiency factors for processing refinery products.

Pages S28-34: **Table S6.** Estimate calculation, oil quality and processing *EI* including bitumen upgrading.

Page S35: **Table S7.** Contribution of CO_2 to CO_2e emitted by oil refineries.

Pages S36-40: **Table S8.** PLS inputs for emissions predicted by *OQ*, and comparison emission estimates.

Page S41: **Table S9.** Estimate calculation, San Francisco Bay Area crude feed *OQ* in 2008.

Pages S42-43: **Figure S1.** Some shifts among hydrogen addition and carbon rejection technologies affecting relationships between (A) hydrotreating and hydrogen production, and (B) fuel mix emission intensity and crude feed density, across districts 1, 2, 3 and 5, 1999-2008.

Pages S44-49: **References.**

Table S1

US District PADD	Year	Refinery crude inputs[a] Feed volume ($m^3/d \cdot 10^4$)	Density (kg/m^3)	Sulfur (kg/m^3)	Source countries	Refinery process capacity[b] Atm. dist. ($m^3/d \cdot 10^4$)	Vacuum dist. ($m^3/d \cdot 10^4$)	Coking & therm. ($m^3/d \cdot 10^4$)	Cat. cracking ($m^3/d \cdot 10^4$)
1	1999	24.436	858.199	8.239	24	24.365	9.802	1.420	10.476
1	2000	24.754	860.182	8.000	23	24.592	9.721	1.440	10.798
1	2001	23.546	866.344	7.710	19	24.958	9.658	1.409	9.924
1	2002	24.246	865.708	7.445	20	25.222	9.742	1.442	9.899
1	2003	25.184	863.436	7.426	21	25.075	9.975	1.448	9.827
1	2004	24.961	865.443	7.789	21	25.025	9.974	1.448	9.827
1	2005	25.422	863.384	7.166	22	25.263	10.150	1.448	9.970
1	2006	23.626	864.122	7.172	21	25.263	10.149	1.448	9.970
1	2007	23.419	864.333	7.260	24	25.263	10.149	1.448	9.970
1	2008	22.115	863.647	7.082	24	25.263	10.149	1.448	9.970
2	1999	53.626	858.252	10.642	15	57.095	23.272	5.880	19.325
2	2000	54.215	860.025	11.352	16	56.984	23.625	6.098	19.189
2	2001	52.609	861.334	11.370	15	56.427	22.989	6.131	18.822
2	2002	51.162	861.019	11.279	20	55.775	22.592	5.698	18.688
2	2003	51.258	862.804	11.648	16	55.587	22.669	5.612	18.475
2	2004	52.482	865.655	11.859	20	55.528	22.961	5.818	18.268
2	2005	52.688	865.655	11.946	23	56.465	23.689	5.962	18.555
2	2006	52.609	865.443	11.597	20	56.506	23.895	5.948	18.538
2	2007	51.480	864.069	11.838	17	57.873	23.169	6.032	18.010
2	2008	51.575	862.594	11.731	16	57.980	23.466	5.923	18.676
3	1999	111.689	869.004	12.861	33	123.434	57.573	15.493	43.165
3	2000	113.024	870.287	12.967	31	123.436	59.107	16.498	43.434
3	2001	115.600	874.428	14.341	28	123.625	58.157	17.318	44.964
3	2002	112.786	876.703	14.466	33	125.817	57.449	18.717	46.010
3	2003	116.013	874.482	14.429	30	126.876	58.417	19.390	45.821
3	2004	119.145	877.791	14.396	33	128.032	60.442	20.047	46.126
3	2005	114.534	878.009	14.399	36	132.323	59.682	19.897	46.475
3	2006	117.253	875.673	14.361	41	133.383	59.850	20.190	46.632
3	2007	117.682	876.975	14.470	37	134.189	61.054	20.938	46.728
3	2008	111.879	878.663	14.937	36	133.771	61.411	21.046	47.311
5	1999	41.973	894.607	11.093	24	49.484	23.172	9.594	12.630
5	2000	43.086	895.853	10.840	23	49.836	23.152	9.714	12.717
5	2001	44.262	893.759	10.993	26	49.542	23.692	9.757	12.695
5	2002	44.787	889.993	10.858	27	48.422	23.419	9.834	12.768
5	2003	45.661	889.098	10.936	29	48.924	23.597	9.671	12.604
5	2004	45.486	888.874	11.200	28	48.723	23.478	9.695	12.717
5	2005	46.090	888.986	11.379	27	49.104	23.538	9.735	12.762
5	2006	45.693	887.648	10.918	30	49.441	23.930	9.759	13.026
5	2007	44.373	885.537	11.069	30	49.609	24.031	10.003	13.332
5	2008	44.739	890.161	12.106	30	49.730	24.411	9.793	13.170
4	1999	8.029	854.468	11.706	3	8.603	3.464	0.663	2.826
4	2000	8.156	859.346	12.031	2	8.094	3.130	0.663	2.705
4	2001	8.077	859.190	11.084	2	8.802	3.549	0.663	2.768
4	2002	8.363	860.234	12.043	2	9.054	3.616	0.676	2.898
4	2003	8.442	861.229	12.488	2	9.019	3.596	0.687	2.906
4	2004	8.856	862.594	11.645	2	9.296	4.255	0.695	2.950
4	2005	8.935	862.910	11.218	2	9.129	3.502	0.711	2.920
4	2006	8.856	860.496	11.359	2	10.018	3.560	0.711	3.121
4	2007	8.681	862.384	11.728	2	10.016	3.472	0.727	3.151
4	2008	8.585	863.120	12.170	2	9.555	3.305	0.989	2.832
US	1999	239.753	869.111	11.559	--	262.981	117.283	33.050	88.422
US	2000	243.235	870.822	11.669	--	262.942	118.735	34.413	88.844
US	2001	244.077	873.510	12.404	--	263.354	118.046	35.278	89.173
US	2002	241.343	873.888	12.322	--	264.289	116.819	36.368	90.263
US	2003	246.558	872.864	12.482	--	265.481	118.253	36.809	89.633
US	2004	250.930	875.185	12.515	--	266.604	121.109	37.703	89.887
US	2005	247.670	875.077	12.426	--	272.284	120.561	37.753	90.682
US	2006	248.052	873.780	12.320	--	274.612	121.385	38.056	91.286
US	2007	245.635	873.888	12.497	--	277.389	124.553	39.148	91.191
US	2008	238.910	875.023	12.863	--	276.299	122.742	39.198	91.959
Energy factor[c]		--	--	--	--	--	--	--	--
CO_2 emission factor (kg/GJ)[c]			--	--	--	--	--	--	--

Table S1 *continued*

US District PADD	Year	Refinery process capacity[b] --- Hydrocracking ($m^3/d \cdot 10^4$)	csHydrotreating ($m^3/d \cdot 10^4$)	psHydrotreating ($m^3/d \cdot 10^4$)	Reforming ($m^3/d \cdot 10^4$)	Alkylation ($m^3/d \cdot 10^4$)	Pol./Dim. ($m^3/d \cdot 10^4$)	Aromatics ($m^3/d \cdot 10^4$)	Isomerization ($m^3/d \cdot 10^4$)
1	1999	0.666	1.320	12.826	4.567	1.282	0.284	0.861	0.447
1	2000	0.666	1.320	12.460	4.468	1.346	0.284	0.852	0.431
1	2001	0.680	0.715	13.030	4.483	1.281	0.212	0.852	0.526
1	2002	0.602	2.131	12.214	4.528	1.292	0.212	0.852	0.611
1	2003	0.602	1.473	13.779	4.548	1.290	0.212	0.852	0.868
1	2004	0.603	1.477	13.513	4.649	1.290	0.212	0.852	0.878
1	2005	0.603	1.477	13.227	4.681	1.335	0.212	0.852	0.878
1	2006	0.615	0.704	13.993	4.681	1.335	0.212	0.852	0.878
1	2007	0.615	0.704	14.057	4.681	1.335	0.212	0.852	0.878
1	2008	0.615	0.704	14.057	4.681	1.335	0.212	0.852	0.878
2	1999	2.533	7.126	29.912	13.533	3.927	0.208	0.924	2.796
2	2000	2.533	6.099	31.548	13.770	3.959	0.208	0.924	2.764
2	2001	2.386	5.401	32.961	13.435	3.940	0.208	0.924	2.757
2	2002	2.434	7.177	31.440	13.357	3.892	0.136	0.888	2.698
2	2003	2.410	7.355	34.844	13.339	3.835	0.136	0.888	2.863
2	2004	2.191	8.214	35.157	13.247	3.807	0.129	0.876	2.900
2	2005	2.798	8.330	38.089	13.368	3.984	0.128	0.838	2.908
2	2006	3.065	7.937	39.013	13.347	3.991	0.128	0.919	2.940
2	2007	3.701	7.929	38.528	13.460	3.911	0.128	0.657	2.944
2	2008	3.652	8.440	36.890	12.972	3.871	0.130	0.657	2.784
3	1999	11.265	18.638	64.038	27.308	8.602	0.310	4.081	4.523
3	2000	11.513	19.190	65.900	27.730	8.599	0.297	4.202	4.347
3	2001	11.842	15.900	70.483	26.840	8.514	0.297	4.260	4.291
3	2002	12.138	18.588	70.415	27.234	9.806	0.353	4.310	4.551
3	2003	11.359	21.356	76.385	27.088	8.982	0.355	4.072	4.572
3	2004	11.868	22.256	82.382	27.517	10.514	0.378	4.386	4.472
3	2005	11.439	22.191	87.486	26.859	9.144	0.347	4.354	4.345
3	2006	11.447	22.301	90.603	26.857	9.253	0.345	4.239	4.312
3	2007	12.059	24.717	91.006	27.458	8.907	0.646	5.026	3.923
3	2008	11.843	22.910	94.039	27.091	9.179	0.646	5.786	4.284
5	1999	8.089	9.630	21.588	8.763	2.928	0.224	0.040	2.097
5	2000	8.119	8.347	22.626	8.849	4.181	0.234	0.040	2.142
5	2001	8.192	8.614	22.642	8.950	2.933	0.234	0.045	2.142
5	2002	8.192	9.472	21.821	8.833	2.999	0.234	0.045	2.147
5	2003	8.043	8.053	23.957	8.847	3.114	0.235	0.045	2.716
5	2004	8.138	8.151	24.765	8.895	3.119	0.238	0.040	2.659
5	2005	8.259	8.154	24.643	8.946	3.153	0.250	0.036	2.727
5	2006	8.896	7.932	25.742	9.400	3.359	0.280	0.021	2.937
5	2007	9.221	8.274	26.024	9.634	3.362	0.228	0.019	3.258
5	2008	9.124	8.123	26.175	9.473	3.337	0.228	0.019	3.171
4	1999	0.079	0.965	4.702	1.901	0.578	0.073	0.000	0.245
4	2000	0.079	0.744	4.368	1.770	0.525	0.067	0.000	0.245
4	2001	0.278	0.437	5.062	1.905	0.586	0.083	0.000	0.236
4	2002	0.079	0.783	4.784	1.889	0.612	0.083	0.000	0.236
4	2003	0.087	0.783	5.090	1.901	0.622	0.083	0.000	0.238
4	2004	0.254	0.836	4.673	1.772	0.566	0.076	0.000	0.239
4	2005	0.087	0.852	5.123	1.917	0.583	0.097	0.000	0.239
4	2006	0.254	1.092	5.444	1.940	0.596	0.097	0.000	0.258
4	2007	0.280	1.092	5.607	1.953	0.604	0.097	0.000	0.264
4	2008	0.087	1.302	5.720	1.816	0.612	0.083	0.000	0.264
US	1999	22.632	37.678	133.066	56.072	17.317	1.099	5.906	10.108
US	2000	22.910	35.699	136.901	56.585	18.609	1.090	6.017	9.929
US	2001	23.379	31.067	144.178	55.613	17.254	1.034	6.080	9.952
US	2002	23.446	38.151	140.674	55.840	18.602	1.018	6.093	10.243
US	2003	22.502	39.021	154.054	55.723	17.842	1.020	5.856	11.258
US	2004	23.054	40.935	160.490	56.081	19.295	1.034	6.154	11.148
US	2005	23.186	41.005	168.568	55.771	18.200	1.033	6.079	11.097
US	2006	24.278	39.967	174.794	56.226	18.534	1.062	6.032	11.324
US	2007	25.876	42.717	175.222	57.186	18.119	1.311	6.554	11.268
US	2008	25.322	41.479	176.881	56.034	18.333	1.299	7.314	11.381
Energy factor[c]		--	--	--	--	--	--	--	--
CO_2 emission factor (kg/GJ)[c]		--	--	--	--	--	--	--	--

Table S1 *continued*

US District PADD	Year	Refinery process capacity[b] Lubes ($m^3/d \cdot 10^4$)	Asphalt ($m^3/d \cdot 10^4$)	Sulfur ($kg/d \cdot 10^6$)	Fuels consumed in refineries[a] H_2 production ($m^3 \cdot 10^8$)	Crude oil ($m^3 \cdot 10^4$)	LPG ($m^3 \cdot 10^4$)	Distillate ($m^3 \cdot 10^4$)	Res. fuel oil ($m^3 \cdot 10^4$)
1	1999	0.368	1.033	0.921	11.783	0.000	2.766	2.035	37.012
1	2000	0.300	0.461	0.921	14.056	0.000	5.008	4.165	38.904
1	2001	0.300	0.461	0.856	11.576	0.000	5.819	8.967	44.675
1	2002	0.299	0.445	1.265	10.232	0.000	4.483	7.631	29.190
1	2003	0.299	0.445	1.301	15.090	0.000	7.854	9.921	28.014
1	2004	0.300	0.445	1.301	15.090	0.000	7.870	7.409	18.013
1	2005	0.300	0.445	1.319	15.297	0.000	11.479	5.819	18.220
1	2006	0.300	0.445	1.319	17.364	0.000	5.231	0.366	14.627
1	2007	0.300	0.445	1.285	13.333	0.000	2.941	0.350	13.132
1	2008	0.300	0.445	1.285	13.333	0.000	0.827	0.461	6.344
2	1999	0.264	3.493	4.436	44.237	0.000	27.123	0.986	43.531
2	2000	0.264	3.763	4.402	44.030	0.000	14.484	0.763	34.166
2	2001	0.264	3.617	4.425	47.751	0.000	13.975	1.288	38.888
2	2002	0.277	3.668	4.672	43.926	0.000	16.439	1.081	29.747
2	2003	0.277	3.727	4.818	40.619	0.000	25.804	0.588	9.380
2	2004	0.277	3.705	4.631	41.032	0.000	17.155	0.588	3.100
2	2005	0.269	3.814	5.140	49.611	0.000	12.385	0.795	2.591
2	2006	0.269	3.897	5.243	77.000	0.000	9.015	0.715	3.275
2	2007	0.269	3.151	4.600	77.931	0.000	13.387	0.747	3.005
2	2008	0.135	3.608	5.200	78.551	0.000	12.783	0.700	3.084
3	1999	1.786	1.930	14.092	146.456	0.159	12.560	1.892	0.191
3	2000	1.801	1.967	15.297	148.833	0.000	13.085	2.798	0.032
3	2001	1.772	1.848	15.266	155.655	0.000	11.018	2.178	0.000
3	2002	1.745	1.904	16.516	160.512	0.000	13.450	1.335	0.000
3	2003	1.793	2.569	17.134	160.512	0.000	17.489	0.700	0.000
3	2004	1.982	2.409	19.395	174.362	0.000	5.898	1.304	0.000
3	2005	2.343	1.936	19.135	172.398	0.000	5.708	1.367	0.064
3	2006	2.351	1.914	19.393	162.269	0.000	4.404	1.765	0.016
3	2007	2.282	1.938	19.013	160.822	0.000	3.307	1.828	0.048
3	2008	2.281	1.938	19.243	164.233	0.000	8.204	1.701	0.048
5	1999	0.437	1.191	4.152	126.301	0.000	18.649	4.086	9.015
5	2000	0.437	1.215	4.152	151.934	0.000	34.150	3.736	11.081
5	2001	0.437	1.078	4.152	149.247	0.000	47.251	4.436	13.609
5	2002	0.342	0.742	4.230	151.004	0.000	19.587	3.307	14.341
5	2003	0.342	0.979	4.331	148.523	0.000	34.484	3.911	11.558
5	2004	0.286	0.920	4.286	147.903	0.000	24.627	3.657	11.495
5	2005	0.286	0.940	4.520	149.557	0.000	36.424	4.022	11.558
5	2006	0.318	0.916	4.911	159.169	0.000	23.339	4.054	12.242
5	2007	0.318	0.940	4.539	162.786	0.000	22.497	3.752	11.813
5	2008	0.318	0.940	5.011	162.786	0.000	23.991	4.642	11.845
4	1999	0.000	0.688	0.381	8.889	0.000	0.636	0.095	3.450
4	2000	0.000	0.671	0.382	8.992	0.000	0.890	0.048	4.786
4	2001	0.000	0.838	0.367	9.612	0.000	0.620	0.111	3.482
4	2002	0.000	0.738	0.368	9.612	0.000	0.700	0.000	3.259
4	2003	0.000	0.738	0.538	9.199	0.000	0.779	0.000	2.671
4	2004	0.000	0.743	0.612	9.509	0.000	1.065	0.016	2.337
4	2005	0.000	0.576	13.577	13.953	0.000	0.382	0.000	2.655
4	2006	0.000	0.796	0.593	13.953	0.000	0.238	0.000	1.924
4	2007	0.000	0.783	0.599	18.191	0.000	0.207	0.000	1.320
4	2008	0.000	0.807	0.595	20.878	0.000	0.779	0.000	0.779
US	1999	2.856	8.335	23.982	337.665	0.159	61.735	9.094	93.198
US	2000	2.803	8.077	25.154	367.845	0.000	67.617	11.511	88.969
US	2001	2.774	7.842	25.066	373.840	0.000	78.683	16.980	100.655
US	2002	2.662	7.498	27.051	375.287	0.000	54.660	13.355	76.536
US	2003	2.710	8.458	28.122	373.943	0.000	86.410	15.120	51.623
US	2004	2.845	8.222	30.225	387.896	0.000	56.615	12.973	34.945
US	2005	3.199	7.712	43.691	400.816	0.000	66.377	12.004	35.088
US	2006	3.239	7.967	31.459	429.756	0.000	42.227	6.900	32.084
US	2007	3.169	7.256	30.036	433.063	0.000	42.338	6.677	29.317
US	2008	3.035	7.737	31.334	439.781	0.000	46.583	7.504	22.099
Energy factor[c]		--	--	--	16.4 MJ/m^3	38.49 GJ/m^3	25.62 GJ/m^3	38.66 GJ/m^3	41.72 GJ/m^3
CO_2 emission factor (kg/GJ)[c]		--	--	--	52.70	78.53	65.76	77.18	83.14

Table S1 *continued*

US District PADD	Year	Fuels consumed in refineries[a] Fuel gas (bl) ($m^3 \bullet 10^5$)	Pet. coke ($m^3 \bullet 10^5$)	Other product ($m^3 \bullet 10^4$)	Natural gas ($m^3 \bullet 10^8$)	Coal (Gg)	Electricity purchased (TWh)	Steam purchased (Tg)
1	1999	32.387	20.538	6.964	11.501	28.123	3.180	1.599
1	2000	31.990	19.093	6.105	12.553	27.216	3.084	1.897
1	2001	32.322	18.975	5.406	9.915	29.030	3.450	1.797
1	2002	33.987	18.805	5.851	11.086	28.123	3.282	1.865
1	2003	35.329	19.649	7.059	8.032	29.030	3.415	1.674
1	2004	35.419	20.377	2.242	9.177	26.308	3.410	2.352
1	2005	35.481	20.369	2.242	10.082	29.937	3.520	2.228
1	2006	33.756	17.541	0.859	10.258	28.123	3.576	2.593
1	2007	36.392	19.036	0.334	8.129	29.030	3.984	2.624
1	2008	33.909	19.393	0.461	7.892	28.123	4.192	2.360
2	1999	76.667	29.697	22.560	26.317	0.000	8.956	1.262
2	2000	77.341	29.335	19.047	30.038	1.814	8.949	0.890
2	2001	76.697	27.643	20.382	26.510	6.350	8.728	2.060
2	2002	73.293	27.689	19.555	27.235	0.000	8.933	2.368
2	2003	72.970	27.357	16.392	26.727	8.165	8.885	2.577
2	2004	79.249	25.339	27.855	29.254	7.257	9.486	2.863
2	2005	79.832	27.572	26.805	30.152	7.257	9.875	2.283
2	2006	78.834	26.236	31.177	32.485	2.722	10.488	3.310
2	2007	78.586	24.963	6.280	33.993	6.350	10.555	4.871
2	2008	77.716	23.856	0.286	39.330	10.886	10.804	4.999
3	1999	181.263	66.223	31.177	147.683	0.000	13.762	8.968
3	2000	184.163	67.454	34.405	147.541	0.000	14.501	11.455
3	2001	177.565	66.822	30.923	138.325	0.000	15.868	13.142
3	2002	181.193	66.891	21.479	129.876	0.000	16.145	14.670
3	2003	194.971	67.972	29.874	121.706	0.000	15.682	14.456
3	2004	190.864	69.595	22.544	111.896	0.000	17.044	14.827
3	2005	177.745	65.660	20.668	112.129	0.000	16.620	15.757
3	2006	198.807	72.481	31.336	112.029	0.000	18.612	17.690
3	2007	192.263	67.964	24.007	102.791	0.000	20.433	28.790
3	2008	181.956	62.598	26.996	107.893	0.000	20.675	28.919
5	1999	72.803	21.174	25.851	34.754	0.000	5.389	8.469
5	2000	74.282	22.314	26.185	38.268	0.000	4.809	8.268
5	2001	77.031	22.827	22.576	34.867	0.000	4.695	7.881
5	2002	70.694	22.640	22.672	38.733	0.000	4.780	7.589
5	2003	74.354	23.823	25.740	37.477	0.000	4.520	8.595
5	2004	73.964	24.441	31.305	35.335	0.000	4.871	8.732
5	2005	72.657	24.438	27.028	34.906	0.000	4.978	8.145
5	2006	71.543	23.133	34.961	35.733	0.000	4.973	8.164
5	2007	72.423	23.087	27.282	37.863	0.000	5.113	8.091
5	2008	68.973	19.651	32.227	39.629	0.000	5.125	8.064
4	1999	11.585	4.442	11.415	6.145	0.000	1.422	0.424
4	2000	11.465	4.153	13.132	5.502	0.000	1.486	0.384
4	2001	11.946	4.302	12.655	5.686	0.000	1.446	0.419
4	2002	11.639	4.262	13.260	6.024	0.000	1.581	0.337
4	2003	13.827	4.040	13.752	5.319	0.000	1.515	0.402
4	2004	13.541	4.372	8.649	5.472	0.000	1.583	0.504
4	2005	13.050	4.496	7.981	6.112	0.000	1.601	0.432
4	2006	13.508	4.480	2.258	7.031	0.000	1.704	0.343
4	2007	13.202	4.884	0.986	6.375	0.000	1.744	0.540
4	2008	14.501	4.571	1.081	6.445	0.000	1.886	0.458
US	1999	374.706	142.074	97.968	226.399	28.123	32.709	20.722
US	2000	379.240	142.348	98.874	233.902	29.030	32.829	22.894
US	2001	375.561	140.570	91.942	215.304	35.380	34.187	25.299
US	2002	370.806	140.287	82.816	212.953	28.123	34.721	26.830
US	2003	391.451	142.841	92.817	199.261	37.195	34.017	27.705
US	2004	393.037	144.125	92.594	191.134	33.566	36.394	29.278
US	2005	378.765	142.535	84.724	193.381	37.195	36.594	28.844
US	2006	396.448	143.871	100.591	197.536	30.844	39.353	32.100
US	2007	392.867	139.933	58.889	189.152	35.380	41.829	44.916
US	2008	377.056	130.069	61.051	201.191	39.009	42.682	44.801
Energy factor[c]		39.82 GJ/m^3	39.98 GJ/m^3	38.66 GJ/m^3	38.27 MJ/m^3	25.80 MJ/kg	3.6 MJ/kWh	2.18 MJ/kg
CO_2 emission factor (kg/GJ)[c]		67.73	107.74	73.20	55.98	99.58	187.78	91.63

Table S1 *continued*

US District PADD	Year	Refinery product yields[a] -- LPG (%)	Fin. motor gasoline (%)	Aviation gasoline (%)	Kerosine jet fuel (%)	Kerosine (%)	Distillate fuel oil (%)	Residual fuel oil (%)	Naphtha for chem FS (%)
1	1999	2.5	46.6	0.2	7.0	0.8	26.3	6.5	0.8
1	2000	2.8	45.2	0.2	6.3	0.8	27.9	6.8	0.8
1	2001	2.9	45.8	0.2	5.3	0.8	29.1	6.6	0.8
1	2002	3.0	46.7	0.3	5.3	0.8	28.1	5.7	0.9
1	2003	3.0	46.4	0.2	5.2	0.8	27.2	7.8	0.8
1	2004	2.6	46.5	0.4	6.1	0.7	26.6	6.9	0.8
1	2005	2.4	46.6	0.3	5.7	0.7	28.8	6.2	0.8
1	2006	2.6	45.8		5.1	0.4	29.2	7.1	1.1
1	2007	3.2	45.5	0.1	5.0	0.5	29.4	7.2	1.1
1	2008	3.3	44.6		5.7	0.6	29.6	7.1	1.1
2	1999	3.7	51.1	0.1	6.6	0.5	24.8	1.6	0.6
2	2000	3.7	50.4	0.1	6.9	0.4	25.7	1.8	0.5
2	2001	3.6	51.1	0.1	6.6	0.4	26.0	2.0	0.6
2	2002	3.5	52.0	0.1	6.7	0.3	25.4	1.8	0.6
2	2003	3.3	51.5	0.1	6.2	0.3	26.0	1.7	0.5
2	2004	3.3	51.6	0.1	6.4	0.3	25.7	1.8	0.8
2	2005	3.1	50.4	0.1	6.5	0.3	27.1	1.6	0.8
2	2006	4.0	49.4	0.1	6.2	0.3	27.3	1.7	0.9
2	2007	3.9	49.8	0.1	6.1	0.1	28.2	1.7	0.9
2	2008	3.5	48.5	0.1	6.3	0.0	30.0	1.6	0.8
3	1999	6.1	44.8	0.2	11.1	0.4	21.1	4.3	2.1
3	2000	6.0	44.7	0.1	11.1	0.4	21.9	4.6	2.2
3	2001	5.6	44.3	0.1	10.5	0.6	22.8	4.8	1.7
3	2002	5.8	45.4	0.1	10.3	0.4	22.3	3.7	2.7
3	2003	5.5	44.8	0.1	9.9	0.4	23.0	4.1	2.6
3	2004	5.3	44.6	0.1	10.0	0.5	23.5	3.9	2.8
3	2005	4.7	43.8	0.1	10.2	0.6	24.5	3.9	2.3
3	2006	4.8	43.5	0.2	9.7	0.4	25.2	3.8	1.9
3	2007	5.0	43.2	0.1	9.4	0.3	26.0	4.1	1.9
3	2008	5.1	41.6	0.1	9.6	0.0	28.4	4.0	1.5
5	1999	2.6	44.7	0.1	15.8	0.2	18.3	8.5	0.2
5	2000	3.1	45.7	0.1	16.2	0.2	18.5	6.8	0.1
5	2001	2.7	45.5	0.1	16.0	0.1	19.2	6.9	0.1
5	2002	2.7	47.3	0.1	16.0	0.1	19.0	6.2	0.1
5	2003	2.9	47.2	0.1	16.0	0.0	19.5	5.8	0.1
5	2004	2.6	47.3	0.1	16.2	0.0	19.5	6.1	0.0
5	2005	2.5	47.3	0.1	16.2	0.0	20.4	5.8	0.0
5	2006	2.8	47.7	0.1	15.3	0.0	20.3	5.8	0.0
5	2007	2.8	46.6	0.1	15.6	0.0	20.8	6.3	0.0
5	2008	2.8	45.6	0.1	17.5	0.0	21.6	5.5	0.0
4	1999	1.3	47.8	0.1	5.4	0.5	28.7	2.3	
4	2000	1.3	47.1	0.1	5.8	0.3	29.1	2.0	0.0
4	2001	1.3	47.4	0.1	5.3	0.3	29.8	2.3	
4	2002	1.1	48.0	0.1	4.8	0.4	29.9	2.1	
4	2003	0.8	47.9	0.1	4.9	0.4	29.5	2.4	
4	2004	0.8	47.5	0.1	4.9	0.3	30.4	2.5	
4	2005	0.7	46.0	0.1	5.4	0.3	30.6	2.7	
4	2006	1.3	46.4	0.1	5.3	0.4	30.6	2.8	
4	2007	1.5	46.3	0.1	5.4	0.3	29.8	2.6	
4	2008	1.6	47.4	0.1	4.8	0.2	31.6	2.2	
US	1999	4.5	46.5	0.2	10.2	0.4	22.3	4.6	1.3
US	2000	4.5	46.2	0.1	10.3	0.4	23.1	4.5	1.3
US	2001	4.3	46.2	0.1	9.8	0.5	23.8	4.6	1.1
US	2002	4.3	47.3	0.1	9.8	0.4	23.2	3.9	1.6
US	2003	4.2	46.9	0.1	9.5	0.4	23.7	4.2	1.5
US	2004	4.0	46.8	0.1	9.7	0.4	23.9	4.1	1.6
US	2005	3.6	46.2	0.1	9.8	0.4	25.0	4.0	1.4
US	2006	3.9	45.8	0.1	9.3	0.3	25.4	4.0	1.2
US	2007	4.1	45.5	0.1	9.1	0.2	26.1	4.2	1.3
US	2008	4.1	44.2	0.1	9.7	0.1	27.8	4.0	1.0
Energy factor[c]		--	--	--	--	--	--	--	--
CO_2 emission factor (kg/GJ)[c]		--	--	--	--	--	--	--	--

Table S1 *continued*

US District PADD	Year	Refinery product yields[a] Oth. oils for chem FS (%)	Special naphtha (%)	Lubricants (%)	Waxes (%)	Petroleum coke (%)	Asphalt & road oil (%)	Fuel gas (%)	Miscellaneous products (%)	Utilization of operable ref. capacity[a] (%)
1	1999		0.1	1.0	0.0	3.1	5.4	3.7	0.1	90.9
1	2000		0.1	0.9	0.1	3.0	6.1	3.5	0.1	91.7
1	2001		0.1	0.9	0.0	3.3	6.0	3.8	0.1	87.2
1	2002		0.1	1.0	0.0	3.1	6.0	3.9	0.1	88.9
1	2003		0.1	1.0	0.0	2.9	5.7	3.8	0.1	92.7
1	2004		0.1	1.1	0.0	3.1	6.2	3.9	0.1	90.4
1	2005		0.1	1.0	0.0	2.9	5.7	3.8	0.1	93.1
1	2006		0.1	1.1	0.0	3.0	5.6	3.6	0.2	86.7
1	2007		0.0	1.0	0.0	3.2	5.0	3.9	0.2	85.6
1	2008		0.0	1.1	0.1	3.3	5.1	3.8	0.2	80.8
2	1999	0.7	0.7	0.6	0.1	4.2	5.6	3.9	0.3	93.3
2	2000	0.4	0.7	0.5	0.1	4.3	5.5	3.9	0.3	94.2
2	2001	0.0	0.6	0.4	0.1	4.3	5.1	4.0	0.3	93.9
2	2002	0.0	0.5	0.5	0.1	4.1	5.3	4.0	0.4	90.0
2	2003	0.0	0.6	0.5	0.1	4.2	5.6	4.1	0.4	91.6
2	2004	0.3	0.1	0.4	0.1	4.3	5.7	4.1	0.4	93.6
2	2005	0.3	0.2	0.4	0.1	4.5	5.7	4.1	0.5	92.9
2	2006	0.2	0.2	0.5	0.1	4.4	6.1	4.1	0.5	92.4
2	2007	0.2	0.1	0.4	0.1	4.3	5.3	4.2	0.4	90.1
2	2008	0.2	0.1	0.4	0.1	4.3	5.3	4.0	0.4	88.4
3	1999	2.5	0.8	1.7	0.2	4.8	1.7	4.1	0.4	94.7
3	2000	2.3	0.4	1.7	0.2	4.8	1.8	4.1	0.4	93.9
3	2001	2.1	0.4	1.6	0.1	5.3	1.6	4.1	0.5	94.8
3	2002	1.9	0.4	1.6	0.1	5.7	1.6	4.2	0.5	91.5
3	2003	2.3	0.4	1.5	0.1	5.7	1.6	4.4	0.5	93.6
3	2004	2.4	0.5	1.6	0.1	5.9	1.5	4.3	0.4	94.1
3	2005	2.1	0.4	1.6	0.1	6.0	1.6	4.3	0.4	88.3
3	2006	2.4	0.4	1.7	0.1	6.2	1.5	4.6	0.5	88.7
3	2007	2.4	0.5	1.7	0.1	6.0	1.3	4.3	0.5	88.7
3	2008	2.3	0.5	1.7	0.1	6.0	1.1	4.4	0.6	83.6
5	1999	0.3	0.1	1.0	0.0	6.1	2.4	5.8	0.2	87.1
5	2000	0.3	0.1	0.9	-0.1	6.3	2.4	5.6	0.3	87.5
5	2001	0.3	0.1	1.0	0.0	6.0	2.1	5.8	0.3	89.1
5	2002	0.3	0.1	0.8	0.0	6.0	2.1	5.5	0.3	90.0
5	2003	0.3	0.1	0.8		6.2	1.9	5.6	0.3	91.3
5	2004	0.3	0.0	0.7		6.1	1.9	5.4	0.3	90.4
5	2005	0.4	0.0	0.7		6.2	1.7	5.1	0.3	91.7
5	2006	0.4	0.1	0.7		6.0	1.8	5.2	0.4	90.5
5	2007	0.3	0.0	0.6		5.8	1.8	5.4	0.4	87.6
5	2008	0.1	0.0	0.8		6.1	1.4	5.1	0.5	88.1
4	1999	0.1	0.0		0.7	3.4	8.8	4.1	0.4	95.7
4	2000	0.1	0.0		0.6	3.3	9.3	3.9	0.4	94.7
4	2001	0.2	0.0		0.6	3.3	8.6	4.1	0.4	90.7
4	2002	0.1			0.5	3.2	9.2	3.8	0.4	91.6
4	2003	0.1			0.4	3.2	9.1	4.5	0.4	91.9
4	2004	0.1			0.4	3.2	9.3	4.2	0.4	95.7
4	2005	0.1	0.0		0.4	3.3	9.5	4.1	0.4	95.5
4	2006	0.1	0.0		0.3	3.3	8.5	4.2	0.4	93.5
4	2007	0.1	0.0		0.0	3.4	8.9	4.2	0.3	91.3
4	2008		0.0		0.0	4.6	6.1	4.6	0.5	89.4
US	1999	1.4	0.6	1.2	0.1	4.7	3.3	4.3	0.3	92.6
US	2000	1.3	0.4	1.2	0.1	4.7	3.4	4.2	0.4	92.6
US	2001	1.1	0.3	1.1	0.1	4.9	3.1	4.3	0.4	92.6
US	2002	1.0	0.3	1.1	0.1	5.1	3.2	4.3	0.4	90.7
US	2003	1.2	0.3	1.1	0.1	5.1	3.2	4.5	0.4	92.6
US	2004	1.3	0.3	1.1	0.1	5.2	3.2	4.4	0.4	93.0
US	2005	1.1	0.2	1.1	0.1	5.3	3.2	4.3	0.4	90.6
US	2006	1.2	0.2	1.2	0.1	5.3	3.2	4.5	0.4	89.7
US	2007	1.3	0.3	1.1	0.1	5.2	2.9	4.4	0.4	88.5
US	2008	1.2	0.3	1.1	0.1	5.3	2.7	4.3	0.5	85.3
Energy factor[c]		--	--	--	--	--	--	--	--	--
CO_2 emission factor (kg/GJ)[c]		--	--	--	--	--	--	--	--	--

Table S1 *continued*

US District PADD	Year	Energy consumed/volume crude feed (GJ/m^3) and CO_2 emitted/vol. crude feed (kg/m^3) for refinery fuels[c] Hydrogen prod. (GJ/m^3)	(kg/m^3)	Crude oil consmd. (GJ/m^3)	(kg/m^3)	LPG consumed (GJ/m^3)	(kg/m^3)	Distillate consmd. (GJ/m^3)	(kg/m^3)	Res. fuel oil cons. (GJ/m^3)	(kg/m^3)	Fuel gas (bl) (GJ/m^3)	(kg/m^3)
1	1999	0.195	10.28	0.000	0.00	0.008	0.52	0.009	0.68	0.173	14.39	1.446	97.93
1	2000	0.230	12.10	0.000	0.00	0.014	0.93	0.018	1.38	0.180	14.94	1.410	95.49
1	2001	0.199	10.48	0.000	0.00	0.017	1.14	0.040	3.11	0.217	18.03	1.498	101.43
1	2002	0.171	8.99	0.000	0.00	0.013	0.85	0.033	2.57	0.138	11.44	1.529	103.58
1	2003	0.242	12.77	0.000	0.00	0.022	1.44	0.042	3.22	0.127	10.57	1.530	103.66
1	2004	0.244	12.88	0.000	0.00	0.022	1.46	0.031	2.43	0.082	6.86	1.548	104.85
1	2005	0.243	12.82	0.000	0.00	0.032	2.08	0.024	1.87	0.082	6.81	1.523	103.13
1	2006	0.297	15.66	0.000	0.00	0.016	1.02	0.002	0.13	0.071	5.88	1.559	105.58
1	2007	0.230	12.13	0.000	0.00	0.009	0.58	0.002	0.12	0.064	5.33	1.695	114.82
1	2008	0.244	12.85	0.000	0.00	0.003	0.17	0.002	0.17	0.033	2.73	1.673	113.30
2	1999	0.334	17.58	0.000	0.00	0.036	2.33	0.002	0.15	0.093	7.71	1.560	105.64
2	2000	0.328	17.31	0.000	0.00	0.019	1.23	0.001	0.12	0.072	5.99	1.556	105.41
2	2001	0.367	19.34	0.000	0.00	0.019	1.23	0.003	0.20	0.084	7.02	1.590	107.72
2	2002	0.347	18.30	0.000	0.00	0.023	1.48	0.002	0.17	0.066	5.53	1.563	105.85
2	2003	0.320	16.89	0.000	0.00	0.035	2.32	0.001	0.09	0.021	1.74	1.553	105.19
2	2004	0.316	16.66	0.000	0.00	0.023	1.51	0.001	0.09	0.007	0.56	1.647	111.58
2	2005	0.381	20.07	0.000	0.00	0.016	1.09	0.002	0.12	0.006	0.47	1.653	111.96
2	2006	0.592	31.19	0.000	0.00	0.012	0.79	0.001	0.11	0.007	0.59	1.635	110.72
2	2007	0.612	32.26	0.000	0.00	0.018	1.20	0.002	0.12	0.007	0.55	1.665	112.80
2	2008	0.616	32.46	0.000	0.00	0.017	1.14	0.001	0.11	0.007	0.57	1.644	111.34
3	1999	0.530	27.94	0.000	0.01	0.008	0.52	0.002	0.14	0.000	0.02	1.771	119.92
3	2000	0.533	28.06	0.000	0.00	0.008	0.53	0.003	0.20	0.000	0.00	1.778	120.40
3	2001	0.545	28.70	0.000	0.00	0.007	0.44	0.002	0.15	0.000	0.00	1.676	113.50
3	2002	0.576	30.33	0.000	0.00	0.008	0.55	0.001	0.10	0.000	0.00	1.753	118.71
3	2003	0.559	29.49	0.000	0.00	0.011	0.70	0.001	0.05	0.000	0.00	1.833	124.18
3	2004	0.592	31.19	0.000	0.00	0.003	0.23	0.001	0.09	0.000	0.00	1.748	118.37
3	2005	0.609	32.08	0.000	0.00	0.003	0.23	0.001	0.10	0.000	0.01	1.693	114.67
3	2006	0.560	29.49	0.000	0.00	0.003	0.17	0.002	0.12	0.000	0.00	1.850	125.28
3	2007	0.553	29.12	0.000	0.00	0.002	0.13	0.002	0.13	0.000	0.00	1.782	120.72
3	2008	0.594	31.28	0.000	0.00	0.005	0.34	0.002	0.12	0.000	0.00	1.774	120.17
5	1999	1.217	64.13	0.000	0.00	0.031	2.05	0.010	0.80	0.025	2.04	1.892	128.17
5	2000	1.426	75.15	0.000	0.00	0.056	3.66	0.009	0.71	0.029	2.44	1.881	127.39
5	2001	1.364	71.86	0.000	0.00	0.075	4.93	0.011	0.82	0.035	2.92	1.899	128.59
5	2002	1.363	71.85	0.000	0.00	0.031	2.02	0.008	0.60	0.037	3.04	1.722	116.63
5	2003	1.315	69.32	0.000	0.00	0.053	3.49	0.009	0.70	0.029	2.41	1.776	120.32
5	2004	1.315	69.29	0.000	0.00	0.038	2.50	0.009	0.66	0.029	2.40	1.774	120.15
5	2005	1.312	69.15	0.000	0.00	0.055	3.65	0.009	0.71	0.029	2.38	1.720	116.48
5	2006	1.409	74.24	0.000	0.00	0.036	2.36	0.009	0.73	0.031	2.55	1.708	115.69
5	2007	1.484	78.18	0.000	0.00	0.036	2.34	0.009	0.69	0.030	2.53	1.781	120.60
5	2008	1.471	77.54	0.000	0.00	0.038	2.48	0.011	0.85	0.030	2.52	1.682	113.92
4	1999	0.448	23.59	0.000	0.00	0.006	0.37	0.001	0.10	0.049	4.08	1.574	106.62
4	2000	0.446	23.50	0.000	0.00	0.008	0.50	0.001	0.05	0.067	5.58	1.534	103.86
4	2001	0.481	25.36	0.000	0.00	0.005	0.35	0.001	0.11	0.049	4.10	1.614	109.29
4	2002	0.465	24.49	0.000	0.00	0.006	0.39	0.000	0.00	0.045	3.70	1.518	102.84
4	2003	0.441	23.22	0.000	0.00	0.006	0.43	0.000	0.00	0.036	3.01	1.787	121.02
4	2004	0.434	22.88	0.000	0.00	0.008	0.56	0.000	0.01	0.030	2.51	1.668	112.99
4	2005	0.631	33.28	0.000	0.00	0.003	0.20	0.000	0.00	0.034	2.82	1.593	107.92
4	2006	0.637	33.58	0.000	0.00	0.002	0.12	0.000	0.00	0.025	2.06	1.664	112.71
4	2007	0.847	44.66	0.000	0.00	0.002	0.11	0.000	0.00	0.017	1.44	1.659	112.38
4	2008	0.983	51.82	0.000	0.00	0.006	0.42	0.000	0.00	0.010	0.86	1.843	124.81
US	1999	0.570	30.01	0.000	0.01	0.018	1.19	0.004	0.31	0.044	3.69	1.705	115.48
US	2000	0.612	32.23	0.000	0.00	0.020	1.28	0.005	0.39	0.042	3.48	1.701	115.21
US	2001	0.619	32.64	0.000	0.00	0.023	1.49	0.007	0.57	0.047	3.92	1.679	113.70
US	2002	0.629	33.14	0.000	0.00	0.016	1.05	0.006	0.45	0.036	3.01	1.676	113.53
US	2003	0.613	32.32	0.000	0.00	0.025	1.62	0.006	0.50	0.024	1.99	1.732	117.31
US	2004	0.625	32.94	0.000	0.00	0.016	1.04	0.005	0.42	0.016	1.32	1.709	115.74
US	2005	0.654	34.49	0.000	0.00	0.019	1.24	0.005	0.40	0.016	1.35	1.668	113.00
US	2006	0.701	36.92	0.000	0.00	0.012	0.79	0.003	0.23	0.015	1.23	1.744	118.10
US	2007	0.713	37.57	0.000	0.00	0.012	0.80	0.003	0.22	0.014	1.13	1.745	118.18
US	2008	0.744	39.23	0.000	0.00	0.014	0.90	0.003	0.26	0.011	0.88	1.722	116.62
Energy factor[c]		16.4 MJ/m^3		38.49 GJ/m^3		25.62 GJ/m^3		38.66 GJ/m^3		41.72 GJ/m^3		39.82 GJ/m^3	
CO_2 emission factor (kg/GJ)[c]		--	52.70	--	78.53	--	65.76	--	77.18	--	83.14	--	67.73

Table S1 *continued*

US District PADD	Year	Energy consumed/volume crude feed (GJ/m^3) and CO_2 emitted/vol. crude feed (kg/m^3) for refinery fuels[c] Petroleum coke (GJ/m^3)	Petroleum coke (kg/m^3)	Other products (GJ/m^3)	Other products (kg/m^3)	Natural gas (GJ/m^3)	Natural gas (kg/m^3)	Coal consumed (GJ/m^3)	Coal consumed (kg/m^3)	Electricity purch. (GJ/m^3)	Electricity purch. (kg/m^3)	Steam purch. (GJ/m^3)	Steam purch. (kg/m^3)
1	1999	0.921	99.186	0.030	2.21	0.493	27.63	0.008	0.81	0.128	24.10	0.039	3.58
1	2000	0.845	91.022	0.026	1.91	0.532	29.76	0.008	0.77	0.123	23.07	0.046	4.19
1	2001	0.883	95.103	0.024	1.78	0.442	24.72	0.009	0.87	0.145	27.14	0.046	4.18
1	2002	0.850	91.531	0.026	1.87	0.479	26.84	0.008	0.82	0.134	25.07	0.046	4.21
1	2003	0.855	92.078	0.030	2.17	0.334	18.72	0.008	0.81	0.134	25.11	0.040	3.64
1	2004	0.894	96.342	0.010	0.70	0.386	21.58	0.007	0.74	0.135	25.30	0.056	5.16
1	2005	0.878	94.557	0.009	0.68	0.416	23.28	0.008	0.83	0.137	25.64	0.052	4.80
1	2006	0.813	87.620	0.004	0.28	0.455	25.48	0.008	0.84	0.149	28.03	0.066	6.01
1	2007	0.890	95.924	0.002	0.11	0.364	20.37	0.009	0.87	0.168	31.51	0.067	6.13
1	2008	0.961	103.488	0.002	0.16	0.374	20.95	0.009	0.90	0.187	35.11	0.064	5.84
2	1999	0.607	65.353	0.045	3.26	0.515	28.80	0.000	0.00	0.165	30.93	0.014	1.29
2	2000	0.593	63.855	0.037	2.72	0.581	32.52	0.000	0.02	0.163	30.57	0.010	0.90
2	2001	0.576	62.009	0.041	3.00	0.528	29.58	0.001	0.08	0.164	30.73	0.023	2.14
2	2002	0.593	63.869	0.040	2.96	0.558	31.24	0.000	0.00	0.172	32.34	0.028	2.53
2	2003	0.585	62.985	0.034	2.48	0.547	30.60	0.001	0.11	0.171	32.10	0.030	2.75
2	2004	0.529	56.979	0.056	4.11	0.584	32.72	0.001	0.10	0.178	33.48	0.033	2.99
2	2005	0.573	61.755	0.054	3.94	0.600	33.59	0.001	0.10	0.185	34.71	0.026	2.37
2	2006	0.546	58.853	0.063	4.59	0.647	36.24	0.000	0.04	0.197	36.92	0.038	3.44
2	2007	0.531	57.224	0.013	0.95	0.692	38.76	0.001	0.09	0.202	37.97	0.057	5.18
2	2008	0.507	54.586	0.001	0.04	0.800	44.76	0.001	0.15	0.207	38.80	0.058	5.30
3	1999	0.649	69.972	0.030	2.16	1.386	77.61	0.000	0.00	0.122	22.82	0.048	4.39
3	2000	0.654	70.430	0.032	2.36	1.369	76.62	0.000	0.00	0.127	23.76	0.061	5.55
3	2001	0.633	68.217	0.028	2.07	1.255	70.23	0.000	0.00	0.135	25.42	0.068	6.22
3	2002	0.650	69.991	0.020	1.48	1.207	67.59	0.000	0.00	0.141	26.51	0.078	7.12
3	2003	0.642	69.143	0.027	2.00	1.100	61.57	0.000	0.00	0.133	25.04	0.074	6.82
3	2004	0.640	68.933	0.020	1.47	0.985	55.12	0.000	0.00	0.141	26.49	0.074	6.81
3	2005	0.628	67.654	0.019	1.40	1.026	57.46	0.000	0.00	0.143	26.88	0.082	7.53
3	2006	0.677	72.950	0.028	2.07	1.002	56.08	0.000	0.00	0.157	29.40	0.090	8.26
3	2007	0.633	68.154	0.022	1.58	0.916	51.27	0.000	0.00	0.171	32.16	0.146	13.39
3	2008	0.613	66.029	0.026	1.87	1.011	56.60	0.000	0.00	0.182	34.23	0.154	14.15
5	1999	0.553	59.534	0.065	4.78	0.868	48.60	0.000	0.00	0.127	23.78	0.121	11.04
5	2000	0.567	61.118	0.064	4.71	0.931	52.13	0.000	0.00	0.110	20.67	0.115	10.50
5	2001	0.565	60.863	0.054	3.95	0.826	46.24	0.000	0.00	0.105	19.65	0.106	9.74
5	2002	0.554	59.655	0.054	3.92	0.907	50.76	0.000	0.00	0.105	19.77	0.101	9.27
5	2003	0.571	61.570	0.060	4.37	0.861	48.17	0.000	0.00	0.098	18.33	0.112	10.30
5	2004	0.589	63.411	0.073	5.34	0.814	45.60	0.000	0.00	0.106	19.83	0.115	10.51
5	2005	0.581	62.572	0.062	4.55	0.794	44.45	0.000	0.00	0.107	20.00	0.106	9.67
5	2006	0.555	59.745	0.081	5.93	0.820	45.90	0.000	0.00	0.107	20.16	0.107	9.78
5	2007	0.570	61.399	0.065	4.77	0.895	50.08	0.000	0.00	0.114	21.34	0.109	9.98
5	2008	0.481	51.835	0.076	5.58	0.929	51.99	0.000	0.00	0.113	21.22	0.108	9.86
4	1999	0.606	65.292	0.151	11.02	0.802	44.92	0.000	0.00	0.175	32.80	0.032	2.89
4	2000	0.558	60.087	0.171	12.48	0.707	39.60	0.000	0.00	0.180	33.74	0.028	2.57
4	2001	0.583	62.862	0.166	12.15	0.738	41.32	0.000	0.00	0.177	33.16	0.031	2.84
4	2002	0.558	60.150	0.168	12.29	0.755	42.28	0.000	0.00	0.186	35.01	0.024	2.21
4	2003	0.524	56.473	0.173	12.63	0.661	36.98	0.000	0.00	0.177	33.24	0.028	2.61
4	2004	0.541	58.265	0.103	7.57	0.648	36.27	0.000	0.00	0.176	33.11	0.034	3.12
4	2005	0.551	59.384	0.095	6.93	0.717	40.15	0.000	0.00	0.177	33.19	0.029	2.64
4	2006	0.554	59.705	0.027	1.98	0.832	46.60	0.000	0.00	0.190	35.64	0.023	2.12
4	2007	0.616	66.398	0.012	0.88	0.770	43.10	0.000	0.00	0.198	37.21	0.037	3.41
4	2008	0.583	62.831	0.013	0.98	0.787	44.07	0.000	0.00	0.217	40.69	0.032	2.92
US	1999	0.649	69.932	0.043	3.17	0.990	55.43	0.001	0.08	0.135	25.27	0.052	4.73
US	2000	0.641	69.064	0.043	3.15	1.008	56.44	0.001	0.08	0.133	25.00	0.056	5.15
US	2001	0.631	67.966	0.040	2.92	0.925	51.78	0.001	0.10	0.138	25.94	0.062	5.67
US	2002	0.637	68.598	0.036	2.66	0.925	51.79	0.001	0.08	0.142	26.65	0.066	6.08
US	2003	0.635	68.369	0.040	2.92	0.847	47.44	0.001	0.11	0.136	25.55	0.067	6.15
US	2004	0.629	67.782	0.039	2.86	0.799	44.71	0.001	0.09	0.143	26.86	0.070	6.39
US	2005	0.630	67.916	0.036	2.65	0.819	45.83	0.001	0.11	0.146	27.36	0.070	6.37
US	2006	0.635	68.447	0.043	3.14	0.835	46.74	0.001	0.09	0.156	29.38	0.077	7.08
US	2007	0.624	67.229	0.025	1.86	0.807	45.20	0.001	0.10	0.168	31.54	0.109	10.01
US	2008	0.596	64.249	0.027	1.98	0.883	49.43	0.001	0.11	0.176	33.09	0.112	10.26
Energy factor[c]		39.98 GJ/m^3		38.66 GJ/m^3		38.27 MJ/m^3		25.80 MJ/kg		3.60 MJ/kWh		2.18 MJ/kg	
CO_2 emission factor (kg/GJ)[c]		--	107.74	--	73.20	--	55.98	--	99.58	--	187.78	--	91.63

Table S1 *continued*

US District PADD	Year	Refinery energy consumed *(EI)*[d] (GJ/m^3)	Fuel mix emission intensity (CO_2)[d] (kg/GJ)	Refinery carbon dioxide emissions[d] (kg/m^3)
1	1999	3.451	81.53	281.3
1	2000	3.430	80.34	275.6
1	2001	3.518	81.85	288.0
1	2002	3.426	81.08	277.8
1	2003	3.364	81.51	274.2
1	2004	3.416	81.46	278.3
1	2005	3.404	81.23	276.5
1	2006	3.440	80.40	276.5
1	2007	3.499	82.28	287.9
1	2008	3.551	83.26	295.7
2	1999	3.368	78.10	263.1
2	2000	3.361	77.56	260.6
2	2001	3.396	77.46	263.1
2	2002	3.393	77.90	264.3
2	2003	3.298	78.00	257.3
2	2004	3.376	77.25	260.8
2	2005	3.496	77.27	270.2
2	2006	3.738	75.84	283.5
2	2007	3.800	75.55	287.1
2	2008	3.858	74.97	289.3
3	1999	4.546	71.61	325.5
3	2000	4.563	71.87	327.9
3	2001	4.348	72.43	315.0
3	2002	4.434	72.71	322.4
3	2003	4.381	72.81	319.0
3	2004	4.204	73.43	308.7
3	2005	4.205	73.24	308.0
3	2006	4.367	74.15	323.8
3	2007	4.226	74.93	316.7
3	2008	4.361	74.48	324.8
5	1999	4.908	70.27	344.9
5	2000	5.189	69.09	358.5
5	2001	5.039	69.38	349.6
5	2002	4.881	69.15	337.5
5	2003	4.885	69.40	339.0
5	2004	4.861	69.89	339.7
5	2005	4.774	69.88	333.6
5	2006	4.862	69.32	337.1
5	2007	5.091	69.12	351.9
5	2008	4.939	68.39	337.8
4	1999	3.843	75.90	291.7
4	2000	3.698	76.25	282.0
4	2001	3.846	75.80	291.6
4	2002	3.726	76.06	283.4
4	2003	3.833	75.56	289.6
4	2004	3.644	76.10	277.3
4	2005	3.830	74.80	286.5
4	2006	3.955	74.48	294.5
4	2007	4.159	74.43	309.6
4	2008	4.475	73.61	329.4
US	1999	4.211	73.46	309.3
US	2000	4.261	73.09	311.5
US	2001	4.172	73.51	306.7
US	2002	4.170	73.62	307.0
US	2003	4.126	73.74	304.3
US	2004	4.052	74.08	300.2
US	2005	4.065	73.98	300.7
US	2006	4.222	73.94	312.1
US	2007	4.221	74.34	313.8
US	2008	4.289	73.90	317.0
Energy factor[c]		--	--	--
CO_2 emission factor (kg/GJ)[c]		--	--	--

Legend and notes for Table S1.

Observations of operating refineries that support the central analysis reported in the main text are based on the data given in Table S1.

a. Refinery crude inputs, fuels consumed, products yield, and capacity utilization are from the U.S. Energy Information Administration (USEIA) *(S1-6)*. Fuel energy consumption for hydrogen production is discussed below. Blank entries for yield of some minor products in some districts and years were blank in the original data reported *(S5)* and were assigned a value of zero in the analysis.

b. Process capacities are volumes that can be processed during 24 hours after making allowances for types and grades of inputs and products, environmental constraints and scheduled downtime, from *Oil & Gas Journal (S7)*. The prefix "cs" or "ps" denotes processing of crude streams (including gas oil and residua) or of product streams, respectively (csHydrotreating thus includes hydrotreating of gas oil, residua and catalytic cracking feeds). Atmospheric and vacuum distillation capacities reported for the BP Ferndale, WA, and Carson, CA, refineries in 2007 are higher than those in 2006 or 2008 although no distillation upgrades are reported at those plants in 2006 or 2007, and reported vacuum distillation capacity exceeded total crude capacity reported at the Ferndale plant *(S7)*. The reported data for those four entries are replaced by the average of 2006 and 2008 atmospheric, and vacuum distillation, capacities for each of those two plants. This results in $49.609 \bullet 10^4$ instead of $50.047 \bullet 10^4$ m^3/day for atmospheric distillation, and $24.031 \bullet 10^4$ instead of $26.709 \bullet 10^4$ m^3/day for vacuum distillation, in those District 5 entries shown for 2007. Analyses including the reported data, including the corrected data, and excluding the observation (for District 5 in 2007), showed that this correction did not affect the results

significantly.

c. Contributions of refinery fuels to refinery energy consumption/m^3 crude feed (GJ/m^3) and refinery mass emissions of CO_2 (kg/m^3 crude feed) are shown. These contributions are calculated using the fuel consumption reported and the energy and emission factors shown below each fuel in the table. The energy factor for hydrogen is for an efficient natural gas-fueled steam methane reforming unit as discussed below. Steam energy is based on latent heat of evaporation at 153 kPa/126 ºC. All other factors for conversions to common energy units (HHV) are from the California Air Resources Board *(S8)*. Emission factors (except for H_2 production) are the fuel emission factors for CO_2 emission from stationary combustion established by USEIA for its voluntary reporting of greenhouse gases program *(S9)*. These emission factors are based on carbon content and oxidation estimates for U.S. fuels quality that the agency derived and documented for its estimates of greenhouse gas emissions in the U.S. *(S10)*. The U.S. grid average factor is applied to purchased electricity. The average of distillate, LPG, and waste oil blended with distillate fuel factors is applied to the "other products" category.

Energy consumed by hydrogen production cannot be calculated from the USEIA fuels data *(S11, S12)*. However, the strong trend of hydroprocessing and hydrogen plant capacity addition shown in Table S1 suggests that U.S. refineries were generally hydrogen-limited, and used most of their available H_2 capacity, during 1999-2008. Energy requirements are assigned to 90% of the hydrogen production capacity reported *(S7)* for these reasons. Energy use for steam reforming of natural gas ranges by approximately 15-18 MJ/m^3 H_2 produced *(S12-15)*, and is greater for less efficient designs and for plants using heavier feeds such as

naphtha. The energy factor used here (16.4 MJ/m^3) is for a modern steam methane reformer using pressure swing absorption and natural gas feed *(S13)*. The CO_2 emissions factor (52.7 kg/GJ) is derived from the same source *(S13)* and is virtually identical to USEPA's estimate of 0.053 t/MM Btu *(S15)*. Steam reformer CO_2 emissions are primarily from the shift reaction rather than direct combustion, and increase with the use of heavier feeds and less efficient hydrogen production methods *(S12, S15)*. Because many refinery hydrogen plants use less efficient technology, naphtha feed or both, the factors used are conservative.

d. Refinery energy intensity (*EI*) (GJ/m^3 crude feed), fuel mix emission intensity (kg/GJ), and emissions (kg/m^3) are shown in the last three columns of the table. *EI* ranges by 57%, from 3.30 to 5.19 GJ/m^3 crude feed, while fuel mix emission intensity ranges from 68.4 to 83.3 kg/GJ (22%) among districts and years. The much larger percentage range for *EI* indicates that differences in total amounts of fuel energy used per volume crude processed have a greater impact on total emissions than differences in the emission intensity of the fuel mix, for these districts and years.

Fuel gas, natural gas, petroleum coke and hydrogen (assumed to be natural gas-fueled herein) account for the vast majority of energy and emissions in all cases but the fuel mix varies between districts and years. Fuel gas accounts for 34% of total energy and emissions in District 5 during 2008, but it accounts for 49% of total energy and 43% of total emissions in District 2 during 2004. Natural gas excluding H_2 production accounts for 10% of energy and 7% of emissions in District 1 during 2003 but 30% of energy and 24% of emissions in District 3 during 1999. Hydrogen accounts for 5% of energy and 3% of emissions in District 1 during 2002, but 30% of energy and 23% of emissions in District 5 during 2008.

Petroleum coke accounts for 10% of energy and 15% of emissions in District 5 during 2008, but it accounts for 27% of energy and 35% of emissions in District 1 during both 1999 and 2008.

Fuel mix emission intensity generally increases with the portion of fuel mix emissions accounted for by coke, which increases with the catalytic cracking/ atmospheric distillation ratio, among districts and years. Petroleum coke is a byproduct of cracking reactions that is burned in cracking catalyst regeneration. Catalytic cracking generally decreases with increasing hydrocracking (capacities/atm. capacity). At the same time, hydrogen production capacity increases with hydrocracking capacity, and with crude feed density. (Other variables also relate to crude density and sulfur content as described in the main text.) Although it varies much less than *EI*, fuel mix emission intensity decreases as *EI*, crude feed density, and crude feed sulfur content increase, among these districts and years.

Table S2. Simplified mixing analysis for potential effects of anomalous oils on crude feeds.

		Refinery crude feed volume data reported[a]				Anomalous oil assumption[c]		Potential crude feed effect[d]	
		Potentially anomalous streams[b]			Other	Predicted by	Excess in	Crude feed	Crude feed
		Stream 1	Stream 2	Stream 3	streams	density, sulfur	anomalous oil	predicted	with anomaly
PADD	Year	(% vol.)	(% vol.)	(% vol.)	(% vol.)	(factor)	(factor)	(factor)	(factor)
1	1999	16.59	14.62	10.82	57.97	1	2	1.00	1.27
1	2000	19.73	11.91	11.51	56.85	1	2	1.00	1.29
1	2001	20.49	12.87	11.51	55.13	1	2	1.00	1.30
1	2002	17.28	12.96	12.32	57.44	1	2	1.00	1.27
1	2003	21.93	14.15	13.46	50.46	1	2	1.00	1.32
1	2004	27.74	12.61	11.06	48.59	1	2	1.00	1.37
1	2005	29.46	13.42	11.68	45.44	1	2	1.00	1.39
1	2006	29.89	14.12	12.27	43.72	1	2	1.00	1.40
1	2007	26.88	17.86	11.21	44.05	1	2	1.00	1.39
1	2008	23.23	18.71	10.97	47.09	1	2	1.00	1.35
2	1999	24.01	5.50	4.49	66.00	1	2	1.00	1.28
2	2000	26.90	5.78	4.00	63.32	1	2	1.00	1.31
2	2001	29.08	5.84	3.33	61.75	1	2	1.00	1.33
2	2002	29.40	5.50	1.93	63.17	1	2	1.00	1.33
2	2003	30.82	5.57	2.52	61.09	1	2	1.00	1.34
2	2004	32.02	4.66	2.26	61.06	1	2	1.00	1.35
2	2005	31.35	3.99	2.46	62.20	1	2	1.00	1.34
2	2006	34.76	4.83	1.63	58.78	1	2	1.00	1.38
2	2007	34.73	4.97	2.17	58.13	1	2	1.00	1.38
2	2008	36.35	4.52	1.94	57.19	1	2	1.00	1.39
3	1999	16.50	14.22	11.78	57.50	1	2	1.00	1.27
3	2000	16.77	14.99	13.60	54.64	1	2	1.00	1.28
3	2001	17.72	15.26	14.84	52.18	1	2	1.00	1.29
3	2002	19.61	14.82	14.71	50.86	1	2	1.00	1.31
3	2003	20.18	14.82	14.64	50.36	1	2	1.00	1.31
3	2004	20.21	15.55	12.22	52.02	1	2	1.00	1.31
3	2005	20.52	14.40	11.24	53.84	1	2	1.00	1.31
3	2006	20.53	13.07	10.73	55.67	1	2	1.00	1.30
3	2007	18.39	13.28	11.69	56.64	1	2	1.00	1.28
3	2008	16.61	13.08	12.52	57.79	1	2	1.00	1.26
4	1999	29.57	70.13	0.30	0.00	1	2	1.00	1.65
4	2000	33.07	66.93	0.00	0.00	1	2	1.00	1.67
4	2001	38.31	61.69	0.00	0.00	1	2	1.00	1.69
4	2002	43.61	56.39	0.00	0.00	1	2	1.00	1.72
4	2003	47.16	52.84	0.00	0.00	1	2	1.00	1.74
4	2004	46.77	53.23	0.00	0.00	1	2	1.00	1.73
4	2005	48.29	51.71	0.00	0.00	1	2	1.00	1.74
4	2006	49.87	50.13	0.00	0.00	1	2	1.00	1.75
4	2007	50.99	49.01	0.00	0.00	1	2	1.00	1.75
4	2008	49.10	50.90	0.00	0.00	1	2	1.00	1.75
5	1999	31.84	5.02	3.25	59.89	1	2	1.00	1.35
5	2000	33.00	5.21	3.80	57.99	1	2	1.00	1.37
5	2001	31.84	5.44	4.25	58.47	1	2	1.00	1.36
5	2002	30.86	3.89	3.59	61.66	1	2	1.00	1.34
5	2003	27.61	8.74	3.75	59.90	1	2	1.00	1.33
5	2004	26.28	8.95	5.50	59.27	1	2	1.00	1.32
5	2005	25.14	10.90	6.48	57.48	1	2	1.00	1.32
5	2006	24.26	10.05	6.88	58.81	1	2	1.00	1.31
5	2007	24.68	9.16	5.92	60.24	1	2	1.00	1.31
5	2008	24.34	10.23	7.58	57.85	1	2	1.00	1.31

Legend and notes for Table S2.

Density and sulfur content can predict unreported characteristics of crude oils more reliably in well-mixed crude feeds than in poorly mixed crude feeds. When multiple streams each comprise a small portion of the feed, if an oil stream of divergent quality is present, it will have less potential to change the quality of the total crude feed. Table S2 presents results from a simplified four-component mixing analysis for potential effects of anomalous oils on the crude feeds processed in each district and year. These results indicate that the District 4 crude feed is less well mixed than those of other districts.

a. Refinery crude feed component streams, shown in percent of total crude feed volume for simplicity of presentation, are from USEIA data on gross crude oil inputs to atmospheric distillation and refinery crude oil imports *(S1, S3),* and California Energy Commission data on refinery inputs of crude produced in California *(S16).*

b. Potentially anomalous streams <u>might</u> be dominated by oils in which unreported characteristics that affect processing occur in anomalously high amounts. The three streams with highest potential to effect the crude feed in this way are shown for each district and year. Component streams of crude feeds are ranked based on their potential for anomalous oil and their volume. Oils from the Western Canadian Sedimentary Basin (WCSB) dominate the highest-ranked stream (stream 1) for districts 2 and 4. The WCSB oil stream includes substantial heavy oil and bitumen sources, which tend to be high in nitrogen and vanadium *(S17-19),* and some of this stream is partially pre-processed *(Table S3).* The other streams are ranked based on their volume and the assumption that oils from a single country of origin or U.S. region may originate from similar geology and have similar anomalies. This

assumption is made to assess the reliability of predictions based on density and sulfur for these crude feeds where more complete data for specific crude feeds are not available, and may overstate the potential for anomalies in the crude feeds processed by districts 1, 2, 3 and 5. The origins *(S3, S16)* and ranks of streams are as follows.

District 1 streams are ranked by volume for country of origin, with Nigeria supplying the largest volume (stream 1) in all years. Stream 2 was from Canada, Angola or Saudi Arabia, stream 3 was from Saudi Arabia, Venezuela, Angola or Norway, and 17-21 countries supplied other streams processed in District 1 annually. District 2 processed Canadian crude as its largest import (stream 1) each year, and its other streams are ranked by volume for foreign country of origin. Stream 2 was from Saudi Arabia in all years, stream 3 was from Nigeria, Venezuela or Algeria, and 12-20 countries supplied other streams refined in District 2 annually. District 3 streams are ranked by volume for foreign country of origin, and Mexico supplied the largest of these inputs (stream 1) in all years. Streams 2 and 3 were from Saudi Arabia or Venezuela, and 25-38 countries supplied other streams refined in District 3 annually.

District 4 processed Canadian crude as its largest import stream in all years, with virtually all of the balance from the U.S., and little or none of its crude feed came from any other country. The Canadian stream (stream 1) is dominated by oils from the WCSB, which have known potential for anomalies. Specific origins of the equal or larger U.S. stream are not reported, however, parts of the WCSB and other oil deposits with similar geology are located in District 4 *(S17)*. Limiting crude transport logistics in the landlocked Rocky Mountain states, which are unique to District 4 and help to explain the limited scope of its

imports relative to those of other districts, might also result in reliance on locally produced U.S. feeds. This circumstantial evidence suggests, but does not confirm, the possibility that both the imported and domestic oils refined here might have similar anomalies. Because of this possibility the U.S. stream refined in District 4 is ranked second (stream 2).

District 5 processes substantial amounts of crude from California and Alaska. The California stream (stream 1) is larger than that from any single foreign country, and includes oils from the San Joaquin Valley, which tend to have high density relative to their sulfur content *(Table S9)*. The other streams are ranked by volume for foreign country of origin. Stream 2 was from Iraq or Saudi Arabia, stream 3 was from Ecuador, Iraq or Saudi Arabia, and 20-27 countries supplied other crude oil streams refined in District 5 annually.

c. An unreported characteristic that affects processing is assumed twice as abundant in the anomalous oil as predicted by the density and sulfur content of that oil. The assumed factor of two appears plausible based on the variability observed for nitrogen, vanadium and nickel in whole crude oils. For example, among all assays of crude oils by NETL after 1969 where density, sulfur, nitrogen and residua yield are reported (N = 728) *(S20),* the highest-divergent 1% of oils had 1.85 times as much nitrogen by weight as predicted by density and sulfur (nonparametric regression by LOWESS, $R^2 = 0.71$). Real anomalies could vary from this factor, but since it is applied to all districts and years, results will scale in proportion to the factor chosen. A lower or higher factor would thus decrease or increase values for all results, but would not change the results for any differences between districts and years. The predicted and (assumed) excess abundance of the unreported characteristic are shown, for the anomalous oil, in the columns under note (c).

d. These results estimate, for each district and year, the potential for crude feeds to have anomalous high content for unreported characteristics that are not predicted by crude feed density and sulfur. They do not show that any such anomaly actually occurred. Potential effects in the total refinery crude feed assume that the anomalous oil is 100% of stream 1, 50% of stream 2, and 25% of stream 3 for each district and year. The percentages are discounted sequentially because of the decreasing likelihood of the same anomaly in multiple separate streams. The predicted factor is assigned to the balance of the streams for each district and year. Results are shown as increases from the predicted crude feed factor of 1.00 on the right of the table.

Relatively well-mixed crude feeds limit the effect of the anomaly in districts 1, 2, 3 and 5 to less than half of its assumed magnitude in the anomalous oil stream. This compares with crude sulfur concentrations four to eight times those of nitrogen and 160 to 500 times those of nickel and vanadium *(S17)*. The ranges of annual estimates for these districts overlap, or adjoin for districts 3 and 5. However, the estimates for District 4 are significantly larger (range: 1.65-1.75) than those for the other districts (combined range: 1.26-1.40). Further, although estimates for the other districts represent an extreme case, the assumption that anomalous oil is 50% of stream 2 might understate the potential effects on the District 4 crude feed, in the event that its Canadian and U.S. inputs both have the same anomaly.

This estimate is limited by the simplified four-component blending analysis and anomalous oil stream assumptions described above, and although it shows that unpredicted anomalies are possible in the District 4 crude feed, it represents an extreme and unlikely scenario for districts 1, 2, 3 and 5.

Table S3. Estimate calculation for Canadian synthetic crude oil (SCO) exports to districts and years.

NR = Not reported

	units	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
SCO yield from bitumen upgraders											
NEB Canada estimate[a]	($m^3 \bullet 10^6$)	18.8	18.3	20.0	25.2	29.0	34.3	31.0	37.7	39.5	37.9
ERCB Alberta estimate[b]	($m^3 \bullet 10^6$)	18.8	18.6	20.3	25.6	29.5	34.7	31.7	38.2	39.9	37.9
Upgrading method[a,b]											
Hydrocracking-based	($m^3 \bullet 10^6$)	3.2	3.0	3.3	3.4	9.3	11.4	12.7	11.9	12.7	11.7
Coking-based	($m^3 \bullet 10^6$)	15.6	15.6	16.9	22.1	21.9	23.3	19.0	26.3	27.1	26.2
SCO to Canadian refineries[c]											
All Canadian refining	($m^3 \bullet 10^6$)	13.3	12.5	12.9	12.7	12.1	16.0	14.8	15.6	17.2	17.0
Alberta refineries	($m^3 \bullet 10^6$)	10.1	9.9	10.4	9.6	8.6	11.8	11.8	12.3	13.8	13.0
Other refineries	($m^3 \bullet 10^6$)	3.2	2.6	2.5	3.1	3.4	4.2	3.1	3.3	3.4	3.9
SCO removals from Alberta[b]	($m^3 \bullet 10^6$)	8.8	7.4	8.9	14.2	17.4	21.1	18.9	24.1	25.0	25.0
Supply-demand balance											
Yield (NEB)-all refining	($m^3 \bullet 10^6$)	5.5	5.8	7.1	12.5	16.9	18.3	16.2	22.0	22.3	20.9
Removals-other ref.	($m^3 \bullet 10^6$)	5.6	4.8	6.4	11.1	14.0	16.9	15.8	20.8	21.6	21.1
Excess supply estimate	($m^3 \bullet 10^6$)	5.6	5.8	7.1	12.5	16.9	18.3	16.2	22.0	22.3	21.1
Total SCO exports											
Estimated by NEB[d]	($m^3 \bullet 10^6$)	6.5	NR	NR	9.4	NR	NR	17.5	NR	NR	19.5
SCO exports to U.S.											
Estimated by NEB[d]	($m^3 \bullet 10^6$)	6.5	NR	NR	9.4	NR	NR	17.4	NR	NR	19.3
% of total exports	(%)	100.0			100.0			99.3			99.2
Estimated by interpolation with recent supply/export ratio[e]	($m^3 \bullet 10^6$)	––	5.9	6.3	––	14.5	17.7	––	22.5	21.7	––
Consolidated estimate	($m^3 \bullet 10^6$)	6.5	5.9	6.3	9.4	14.5	17.7	17.4	22.5	21.7	19.3
Supply-export balance	($m^3 \bullet 10^6$)	-0.9	-0.1	0.8	3.2	2.4	0.6	-1.3	-0.5	0.7	1.8
SCO exports to U.S. refining districts estimated by NEB[d]											
PADD 1	($m^3 \bullet 10^6$)	0.37	NR	NR	0.26	NR	NR	0.77	NR	NR	0.46
PADD 2	($m^3 \bullet 10^6$)	5.36	NR	NR	6.02	NR	NR	11.89	NR	NR	13.68
PADD 3	($m^3 \bullet 10^6$)	0.00	NR	NR	0.27	NR	NR	0.07	NR	NR	0.09
PADD 4	($m^3 \bullet 10^6$)	0.77	NR	NR	2.36	NR	NR	3.25	NR	NR	2.49
PADD 5	($m^3 \bullet 10^6$)	0.00	NR	NR	0.45	NR	NR	1.44	NR	NR	2.62
SCO exports to districts estimated by interpolation with to recent U.S. SCO portions[e]											
PADD 1	($m^3 \bullet 10^6$)	––	0.28	0.24	––	0.49	0.69	––	0.84	0.66	––
PADD 2	($m^3 \bullet 10^6$)	––	4.52	4.41	––	9.53	11.86	––	15.56	15.15	––
PADD 3	($m^3 \bullet 10^6$)	––	0.06	0.12	––	0.30	0.22	––	0.10	0.10	––
PADD 4	($m^3 \bullet 10^6$)	––	0.97	1.30	––	3.35	3.70	––	3.77	3.21	––
PADD 5	($m^3 \bullet 10^6$)	––	0.10	0.20	––	0.87	1.26	––	2.26	2.55	––
U.S. exports–PADDs balance	($m^3 \bullet 10^6$)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Legend and notes for Table S3.

Table S3 shows data, reported exports, and calculated estimates for synthetic crude oil (SCO) volume exported from Canada and processed in each district and year. Reported SCO exports are estimates, and these are reported as annual volumes at three-year intervals. Values for the years 2000, 2001, 2003, 2004, 2006 and 2007 are estimated by interpolation based on reported data for the two proximate years. For example, reported data for 1999 and 2002 are used to estimate exported SCO processed in 2000. These estimates thus assume there was no unknown factor that changed the relationship of exports to supply or refinery capacity greatly between the estimated year and the years immediately before and after that year. Results indicate differences between districts in SCO inputs, increasing SCO inputs with time for districts 2 and 4, and that, especially in the earlier years, the SCO came mainly from coking-based upgraders. However, the exact volume and refining characteristics of SCO processed in specific districts and years is uncertain. Notes cited in the table further discuss the sources, data quality, and methods for estimates below.

a. The first estimate of annual SCO yield for 1999-2008 is from the National Energy Board of Canada (NEB) *(S21)*.
b. The second estimate of SCO yield for 1999-2008, and yield by upgrading method for 2000-2008, are from the Energy Resources Conservation Board of Alberta (ERCB) *(S22)*. Yield by upgrader in 1999 is from the NEB *(S21)*. The exact volumes from coking- and hydrocracking-based upgrading are uncertain. One major upgrader that primarily uses the coking method also uses hydrocracking *(S22)*. Most (75%) of the SCO yield from this upgrader is assigned to coking and 25% is assigned to hydrocracking in the table.

c. SCO inputs to Canadian refineries are from Statistics Canada *(S23)*. The agency reports these inputs for light SCO, however, some intermediate and heavy crude streams from the Western Canadian Sedimentary Basin (WCSB) are delivered as blends that may contain SCO. The SCO in such blends may not be reported, for some exports or refinery inputs.

d. SCO exports, including exports the U.S. and to each U.S. district, are estimated by the NEB for 1999 *(S24),* 2002 *(S25),* 2005 *(S26),* and 2008 *(S27)*. The U.S. receives nearly all these exports, however, estimated exports do not balance exactly with the excess supply of SCO estimated to be available after Canadian usage of these oils. NEB export estimates appear to exceed available supply by 0.9 and 1.3 million m^3 in 1999 and 2005, while supply appears to exceed NEB export estimates by 3.2 and 1.8 million m^3 in 2002 and 2008, respectively. This is shown in the "supply-export balance" line of the table. These differences are small for some estimation purposes, but they approach or exceed the total exports estimated for some districts and years. Refining characteristics of the SCO exports are not reported.

e. Although reported only at three-year intervals, exports increase steadily with supply, and their apportionment among the districts changes little over these intervals. This is explained by the need for disposition of the SCO created, and the unique logistical constraints posed by transport and refining of SCO from the WCSB in each district. These constraints allow a rough estimate of the relative SCO volumes exported and refined in the intervening years.

First, total U.S. exports are estimated for years when they are not reported. The excess supply estimate for each such year is multiplied by the weighted average fraction of supply exported in the two nearest reported years. This weighted average is calculated using a 2:1 ratio to give twice as much weight to the proximate year (e.g., 1999 for the 2000 estimate)

and half as much weight to the year more distant in time (2002 in this example). The supply-export balance line of the table shows that these interpolated estimates generally compare more closely with excess supply than do the reported estimates.

SCO exports to districts are then estimated by apportioning the estimated total U.S. exports for the year to be estimated based on the weighted average of each district's share of total SCO exports in the two nearest reported years. This weighted average is calculated using a 2:1 ratio to give twice as much weight to the proximate year (e.g., 1999 for the 2000 estimate) and half as much weight to the year more distant in time (2002 in this example). The bottom line of the table shows that these SCO estimates for districts balance with total estimated SCO exports to the U.S. for each year.

These estimates should be interpreted with caution as discussed above. Nevertheless, they provide evidence that SCO comprised an appreciable portion of crude refined during some years in District 2, and especially District 4, which refines much less oil in total than other districts *(Table S1)*. The estimates suggest that SCO accounts for more than 10% of District 4 crude feeds and up to 8% of District 2 feeds, in some years. Reported and estimated Canadian SCO accounted for less than 2% of the crude feeds processed in districts 1, 3 and 5 during 1999-2008.

Table S 4. Evidence for effects of synthetic oil (SCO) on refinery processing during 1999-2008 in District 4.

		Refinery observations for selected parameters[a]					SCO % vol. of refinery crude feed[b]	Predictions based on non-SCO feeds[c]					
PADD	Year	Crude feed density (kg/m^3)	H^2 production capacity (m^3/m^3)	Conversion capacity (m^3/m^3)	Crude stream hydrotreating capacity (m^3/m^3)	Refinery energy intensity (*EI*) (GJ/m^3)	(%)	H_2 predicted by crude fd. density Predicted (m^3/m^3)	Excess (m^3/m^3)	csHydrotreating pred. by conv. cap. Predicted (m^3/m^3)	Excess (m^3/m^3)	Energy for excess H_2 production/m^3 crude feed[d] (GJ/m^3)	(% *EI*)
1	1999	858.20	13.25	0.516	0.054	3.451	0.41	19.60	--	0.122	--	--	--
1	2000	860.18	15.66	0.525	0.054	3.430	0.31	24.22	--	0.130	--	--	--
1	2001	866.34	12.71	0.481	0.029	3.518	0.28	38.66	--	0.094	--	--	--
1	2002	865.71	11.11	0.474	0.084	3.426	0.30	37.16	--	0.087	--	--	--
1	2003	863.44	16.49	0.474	0.059	3.364	0.53	31.83	--	0.087	--	--	--
1	2004	865.44	16.52	0.475	0.059	3.416	0.76	36.54	--	0.088	--	--	--
1	2005	863.38	16.59	0.476	0.058	3.404	0.83	31.70	--	0.089	--	--	--
1	2006	864.12	18.83	0.476	0.028	3.440	0.98	33.44	--	0.090	--	--	--
1	2007	864.33	14.46	0.476	0.028	3.499	0.77	33.93	--	0.090	--	--	--
1	2008	863.65	14.46	0.476	0.028	3.551	0.57	32.32	--	0.090	--	--	--
2	1999	858.25	21.23	0.486	0.125	3.368	2.74	19.73	1.50	0.097	0.028	0.022	0.66
2	2000	860.03	21.17	0.488	0.107	3.361	2.28	23.85	--	0.099	0.008	--	--
2	2001	861.33	23.18	0.485	0.096	3.396	2.30	26.91	--	0.096	--	--	--
2	2002	861.02	21.58	0.481	0.129	3.393	3.22	26.17	--	0.093	0.035	--	--
2	2003	862.80	20.02	0.477	0.132	3.298	5.09	30.35	--	0.090	0.043	--	--
2	2004	865.65	20.25	0.473	0.148	3.376	6.19	37.04	--	0.087	0.061	--	--
2	2005	865.65	24.07	0.484	0.148	3.496	6.18	37.04	--	0.096	0.052	--	--
2	2006	865.44	37.33	0.488	0.140	3.738	8.10	36.54	0.79	0.099	0.042	0.012	0.31
2	2007	864.07	36.89	0.479	0.137	3.800	8.06	33.31	3.58	0.092	0.045	0.053	1.39
2	2008	862.59	37.12	0.487	0.146	3.858	7.27	29.85	7.26	0.098	0.047	0.107	2.78
3	1999	869.00	32.51	0.566	0.151	4.546	0.00	44.95	--	0.165	--	--	--
3	2000	870.29	33.03	0.579	0.155	4.563	0.01	47.99	--	0.175	--	--	--
3	2001	874.43	34.50	0.600	0.129	4.348	0.03	57.86	--	0.193	--	--	--
3	2002	876.70	34.95	0.611	0.148	4.434	0.07	63.32	--	0.203	--	--	--
3	2003	874.48	34.66	0.604	0.168	4.381	0.07	57.99	--	0.196	--	--	--
3	2004	877.79	37.31	0.610	0.174	4.204	0.05	65.94	--	0.201	--	--	--
3	2005	878.01	35.69	0.588	0.168	4.205	0.02	66.46	--	0.183	--	--	--
3	2006	875.67	33.33	0.587	0.167	4.367	0.02	60.85	--	0.182	--	--	--
3	2007	876.98	32.83	0.594	0.184	4.226	0.02	63.97	--	0.188	--	--	--
3	2008	878.66	33.64	0.600	0.171	4.361	0.02	68.04	--	0.193	--	--	--
4	1999	854.47	28.31	0.415	0.112	3.843	2.64	10.96	17.34	0.040	0.073	0.256	6.66
4	2000	859.35	30.44	0.426	0.092	3.698	3.25	22.27	8.17	0.049	0.043	0.121	3.26
4	2001	859.19	29.92	0.421	0.050	3.846	4.43	21.91	8.01	0.045	0.005	0.118	3.07
4	2002	860.23	29.09	0.404	0.087	3.726	7.73	24.34	4.75	0.031	0.056	0.070	1.88
4	2003	861.23	27.94	0.408	0.087	3.833	10.86	26.66	1.28	0.034	0.053	0.019	0.49
4	2004	862.59	28.02	0.419	0.090	3.644	11.44	29.85	--	0.043	0.047	--	--
4	2005	862.91	41.87	0.407	0.093	3.830	9.98	30.59	11.28	0.034	0.060	0.167	4.35
4	2006	860.50	38.16	0.408	0.109	3.955	11.67	24.95	13.21	0.034	0.075	0.195	4.93
4	2007	862.38	49.76	0.415	0.109	4.159	10.13	29.36	20.39	0.040	0.069	0.301	7.24
4	2008	863.12	59.86	0.409	0.136	4.475	7.94	31.09	28.78	0.035	0.101	0.425	9.49
5	1999	894.61	69.93	0.613	0.195	4.908	0.00	107.06	--	0.204	--	--	--
5	2000	895.85	83.53	0.613	0.167	5.189	0.06	110.15	--	0.204	--	--	--
5	2001	893.76	82.53	0.619	0.174	5.039	0.13	104.95	--	0.209	--	--	--
5	2002	889.99	85.44	0.636	0.196	4.881	0.28	95.65	--	0.224	--	--	--
5	2003	889.10	83.17	0.620	0.165	4.885	0.52	93.45	--	0.210	--	--	--
5	2004	888.87	83.17	0.627	0.167	4.861	0.76	92.90	--	0.216	--	--	--
5	2005	888.99	83.44	0.626	0.166	4.774	0.86	93.18	--	0.216	--	--	--
5	2006	887.65	88.20	0.641	0.160	4.862	1.35	89.89	--	0.228	--	--	--
5	2007	885.54	89.90	0.656	0.167	5.091	1.58	84.73	5.17	0.242	--	0.076	1.50
5	2008	890.16	89.68	0.645	0.163	4.939	1.60	96.07	--	0.232	--	--	--

Legend and notes for Table S4.

Table S4 presents results from analysis of synthetic crude oil (SCO) effects on refining. Canadian export estimates *(Table S3)* suggest that during 1999-2008 SCO from Western Canada was 2-8% and 2-12% of crude feeds in districts 2 and 4, respectively. This SCO stream yields more and lower quality gas oil as compared with typical whole crude oils, and can require more hydroprocessing in refineries *(S24, S25)*. Crude density correlates with hydrogen demand for crude oils generally but does not correlate well for some SCO *(S14)*. Reported hydrogen capacity is compared with that predicted by crude feed density, and reported crude stream hydrotreating capacity is compared with that predicted by conversion capacity, among districts and years. Crude stream hydrotreating processes gas oil, residua and catalytic cracking feeds *(Table S1)*. These comparisons provide information about the relationship of hydrogen production to hydrogen use in processing gas oil, including gas oil from refinery SCO inputs. Hydrogen production in excess of that predicted by crude feed density is then compared with total refinery processing requirements on an energy basis.

Results suggest that SCO affects hydroprocessing and hydrogen production in refineries and may have increased refinery energy intensity significantly during some years in District 4. Hydrogen excesses are found only when SCO was present in crude feeds, and are found during four years in District 2 and nine years in District 4. Hydrotreating excesses are found only when estimated SCO inputs exceeded 2% of crude feeds and occurred during nine years in District 2 and ten years in District 4. The magnitude of hydrogen excesses generally increased with that of hydrotreating excesses and both were larger in District 4 than in District 2. Energy use for excess hydrogen production was minimal in District 2, but in District 4 it exceeded 5% of total

refinery energy consumed during three years, and exceeded 9% of total refinery energy in 2008. The magnitude of hydrogen excesses is not well correlated with the estimated percentage of SCO in crude feeds, especially in District 4. The extent to which this poor correlation reflects unreported changes in the quality of SCO inputs, unreported changes in the quality of the balance of the poorly-mixed District 4 crude feed *(Table S2),* or errors in SCO volume estimates *(Table S3),* could not be determined with available data.

a. Refinery observations shown on the left of the table are based on the data given in Table S1. Capacities/m^3 atmospheric distillation capacity are shown.
b. The percentage of total refinery crude feed volume comprised of SCO is estimated based on estimated SCO exports from Table S3 and reported total crude inputs from Table S1. The SCO export estimates are uncertain, as detailed in Table S3.
c. Predictions shown are from PLS regression on all data for districts where estimated SCO inputs never exceeded 2% of total crude feeds during 1999-2008 (districts 1, 3 and 5). R-squared values are 0.88 for hydrogen production capacity predicted by crude feed density, and 0.85 for crude stream hydrotreating capacity predicted by conversion capacity. These predictions are "blind" to the presence of SCO in that it was not included as a variable in either of these two PLS models. Predictions and excesses shown are based on the upper 95% confidence for observations. Observed values exceed the lower 95% confidence (not shown) for all comparisons.
d. Energy consumed for the excess in hydrogen production capacity, which is shown as cubic meters H_2/m^3 atmospheric distillation capacity in this table, is calculated using the energy (16.4 MJ/m^3 H_2) and capacity utilization (90%) factors from Table S1.

Table S5. Efficiency factors for processing refinery products.

Product	Efficiency factor (%)	Average specific gravity
Light liquids		
Gasoline	86.4	0.737
Diesel	91.0	0.845
Kerosine	92.2	0.814
Naphtha	92.7	0.756
Other products		
Lube stocks	80.5	0.889
Waxes	80.5	0.799
Asphalt	84.9	1.038
Coke	86.3	0.967
Fuel gas	90.0	0.844
Heavy fuel oil	91.0	0.946
LPG	92.7	0.539
Residual oil	94.1	0.946

Legend and notes for Table S5.

Product-specific processing energy efficiency factors for a current typical U.S. refinery (mass-based) from reference *S11*, and average specific gravities of North American products from reference *S28*. These values were used with yield data from Table S1 to estimate energy use for products processing ("Eproducts"). The Eproducts estimates for refining districts and years are used, with *S*, *d*, capacity utilized, and products ratio observations from data in Table S1, in the Eproducts v. *OQ* comparison reported in Table 1 of the main text.

Table S6. Estimate calculation, oil quality and processing *EI* including bitumen upgrading.

		Refinery observations[a]				Cap.	Prod.	Synthetic crude oil		Coking : hy-
		Crude input	Density	*S*	*EI*	utilized	ratio	input estimate[b]		drocracking[b]
PADD	Year	($m^3/d \bullet 10^4$)	(kg/m^3)	(kg/m^3)	(GJ/m^3)	(%)	(ratio)	($m^3/d \bullet 10^4$)	(%)	(ratio)
1	1999	24.436	858.20	8.24	3.451	90.9	3.668	0.101	0.41	4.8
1	2000	24.754	860.18	8.00	3.430	91.7	3.489	0.077	0.31	5.2
1	2001	23.546	866.34	7.71	3.518	87.2	3.479	0.065	0.28	5.2
1	2002	24.246	865.71	7.45	3.426	88.9	3.605	0.073	0.30	6.5
1	2003	25.184	863.44	7.43	3.364	92.7	3.321	0.134	0.53	2.4
1	2004	24.961	865.44	7.79	3.416	90.4	3.398	0.190	0.76	2.0
1	2005	25.422	863.38	7.17	3.404	93.1	3.756	0.212	0.83	1.5
1	2006	23.626	864.12	7.17	3.440	86.7	3.522	0.231	0.98	2.2
1	2007	23.419	864.33	7.26	3.499	85.6	3.443	0.181	0.77	2.1
1	2008	22.115	863.65	7.08	3.551	80.8	3.400	0.125	0.57	2.2
2	1999	53.626	858.25	10.64	3.368	93.3	4.077	1.469	2.74	4.8
2	2000	54.215	860.03	11.35	3.361	94.2	4.132	1.238	2.28	5.2
2	2001	52.609	861.33	11.37	3.396	93.9	4.313	1.210	2.30	5.2
2	2002	51.162	861.02	11.28	3.393	90.0	4.345	1.648	3.22	6.5
2	2003	51.258	862.80	11.65	3.298	91.6	4.281	2.611	5.09	2.4
2	2004	52.482	865.65	11.86	3.376	93.6	4.167	3.250	6.19	2.0
2	2005	52.688	865.65	11.95	3.496	92.9	4.207	3.258	6.18	1.5
2	2006	52.609	865.44	11.60	3.738	92.4	3.907	4.264	8.10	2.2
2	2007	51.480	864.07	11.84	3.800	90.1	4.161	4.152	8.06	2.1
2	2008	51.575	862.59	11.73	3.858	88.4	4.333	3.747	7.27	2.2
3	1999	111.689	869.00	12.86	4.546	94.7	3.120	0.000	0.00	4.8
3	2000	113.024	870.29	12.97	4.563	93.9	3.120	0.015	0.01	5.2
3	2001	115.600	874.43	14.34	4.348	94.8	3.128	0.033	0.03	5.2
3	2002	112.786	876.70	14.47	4.434	91.5	3.251	0.073	0.07	6.5
3	2003	116.013	874.48	14.43	4.381	93.6	3.160	0.081	0.07	2.4
3	2004	119.145	877.79	14.40	4.204	94.1	3.228	0.060	0.05	2.0
3	2005	114.534	878.01	14.40	4.205	88.3	3.316	0.020	0.02	1.5
3	2006	117.253	875.67	14.36	4.367	88.7	3.176	0.027	0.02	2.2
3	2007	117.682	876.98	14.47	4.226	88.7	3.205	0.027	0.02	2.1
3	2008	111.879	878.66	14.94	4.361	83.6	3.229	0.026	0.02	2.2
5	1999	41.973	894.61	11.09	4.908	87.1	2.952	0.001	0.00	4.8
5	2000	43.086	895.85	10.84	5.189	87.5	3.160	0.027	0.06	5.2
5	2001	44.262	893.76	10.99	5.039	89.1	3.231	0.056	0.13	5.2
5	2002	44.787	889.99	10.86	4.881	90.0	3.460	0.124	0.28	6.5
5	2003	45.661	889.10	10.94	4.885	91.3	3.487	0.238	0.52	2.4
5	2004	45.486	888.87	11.20	4.861	90.4	3.551	0.345	0.76	2.0
5	2005	46.090	888.99	11.38	4.774	91.7	3.700	0.394	0.86	1.5
5	2006	45.693	887.65	10.92	4.862	90.5	3.615	0.618	1.35	2.2
5	2007	44.373	885.54	11.07	5.091	87.6	3.551	0.700	1.58	2.1
5	2008	44.739	890.16	12.11	4.939	88.1	3.803	0.717	1.60	2.2
4	1999	8.029	854.47	11.71	3.843	95.1	3.910	0.212	2.64	4.8
4	2000	8.156	859.35	12.03	3.698	94.7	3.943	0.265	3.25	5.2
4	2001	8.077	859.19	11.08	3.846	90.7	3.986	0.357	4.43	5.2
4	2002	8.363	860.23	12.04	3.726	91.6	4.078	0.647	7.73	6.5
4	2003	8.442	861.23	12.49	3.833	91.9	3.962	0.917	10.86	2.4
4	2004	8.856	862.59	11.65	3.644	95.7	3.981	1.013	11.44	2.0
4	2005	8.935	862.91	11.22	3.830	95.5	3.887	0.892	9.98	1.5
4	2006	8.856	860.50	11.36	3.955	93.5	3.962	1.033	11.67	2.2
4	2007	8.681	862.38	11.73	4.159	91.3	3.900	0.879	10.13	2.1
4	2008	8.585	863.12	12.17	4.475	89.4	4.291	0.682	7.94	2.2

Table S6. Estimate calculation, oil quality and processing *EI* including bitumen upgrading.
Continued

		Bitumen upgrading estimate[c]			Upgrading and refining estimate				Estimate compared
		Density$_{add}$[d]	S_{add}[e]	EI_{add}[f]	Density$_{adj}$[g]	S_{adj}[h]	EI_{adj}[i]	EI_{tp}[j]	to *OQ* prediction[k]
PADD	Year	(kg/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(kg/m^3)	(GJ/m^3)	(GJ/m^3)	(±% 95% Conf.)
1	1999	0.45	0.17	0.022	858.65	8.41	3.473	3.271	--
1	2000	0.34	0.13	0.017	860.52	8.13	3.447	3.372	--
1	2001	0.30	0.11	0.015	866.65	7.82	3.533	3.579	--
1	2002	0.33	0.12	0.016	866.04	7.57	3.442	3.533	--
1	2003	0.57	0.22	0.030	864.01	7.65	3.394	3.531	--
1	2004	0.81	0.32	0.043	866.25	8.11	3.459	3.623	--
1	2005	0.87	0.35	0.048	864.26	7.52	3.452	3.470	--
1	2006	1.04	0.41	0.055	865.17	7.58	3.495	3.488	--
1	2007	0.82	0.32	0.044	865.16	7.58	3.543	3.489	--
1	2008	0.60	0.24	0.032	864.25	7.32	3.583	3.393	--
2	1999	3.00	1.12	0.148	861.26	11.76	3.516	3.546	--
2	2000	2.51	0.93	0.123	862.53	12.28	3.484	3.634	--
2	2001	2.52	0.94	0.124	863.86	12.31	3.520	3.662	--
2	2002	3.56	1.30	0.172	864.58	12.58	3.565	3.667	--
2	2003	5.45	2.12	0.285	868.25	13.77	3.583	3.925	--
2	2004	6.58	2.59	0.349	872.24	14.45	3.725	4.179	-2%
2	2005	6.48	2.62	0.355	872.14	14.57	3.852	4.168	--
2	2006	8.65	3.39	0.455	874.09	14.98	4.193	4.321	--
2	2007	8.59	3.37	0.454	872.66	15.21	4.254	4.210	--
2	2008	7.75	3.03	0.408	870.35	14.76	4.266	4.038	--
3	1999	0.00	0.00	0.000	869.00	12.86	4.546	4.117	2%
3	2000	0.02	0.01	0.001	870.30	12.97	4.563	4.173	1%
3	2001	0.03	0.01	0.002	874.46	14.35	4.350	4.446	--
3	2002	0.07	0.03	0.004	876.78	14.49	4.437	4.504	--
3	2003	0.07	0.03	0.004	874.56	14.46	4.385	4.440	--
3	2004	0.05	0.02	0.003	877.84	14.42	4.207	4.575	--
3	2005	0.02	0.01	0.001	878.03	14.41	4.206	4.512	--
3	2006	0.02	0.01	0.001	875.70	14.37	4.369	4.434	--
3	2007	0.02	0.01	0.001	877.00	14.48	4.227	4.493	--
3	2008	0.02	0.01	0.001	878.69	14.95	4.362	4.541	--
5	1999	0.00	0.00	0.000	894.61	11.09	4.909	5.082	--
5	2000	0.07	0.03	0.003	895.92	10.87	5.192	5.097	--
5	2001	0.14	0.05	0.007	893.90	11.04	5.046	5.023	--
5	2002	0.31	0.11	0.015	890.30	10.97	4.896	4.834	--
5	2003	0.56	0.22	0.029	889.65	11.15	4.914	4.825	--
5	2004	0.81	0.32	0.043	889.68	11.52	4.903	4.830	--
5	2005	0.90	0.36	0.049	889.88	11.74	4.824	4.841	--
5	2006	1.44	0.57	0.076	889.09	11.48	4.938	4.793	--
5	2007	1.68	0.66	0.089	887.22	11.73	5.180	4.707	2%
5	2008	1.71	0.67	0.090	891.87	12.78	5.029	4.939	--
4	1999	2.89	1.08	0.143	857.36	12.78	3.986	3.482	4%
4	2000	3.57	1.32	0.175	862.91	13.35	3.873	3.750	--
4	2001	4.86	1.80	0.239	864.05	12.88	4.085	3.726	--
4	2002	8.54	3.13	0.414	868.78	15.17	4.139	4.065	--
4	2003	11.62	4.53	0.608	872.85	17.01	4.441	4.377	--
4	2004	12.16	4.79	0.645	874.76	16.44	4.289	4.459	--
4	2005	10.46	4.23	0.574	873.37	15.45	4.404	4.352	--
4	2006	12.45	4.87	0.655	872.94	16.23	4.610	4.349	--
4	2007	10.79	4.24	0.570	873.17	15.96	4.729	4.331	1%
4	2008	8.47	3.31	0.446	871.59	15.48	4.921	4.152	9%

Legend and notes for Table S6.

Table S6 presents an estimate of oil quality and processing energy for total oil processing, including refining and pre-processing for that portion of refinery crude feeds comprised of synthetic crude oil (SCO), for each district and year. Coking- and hydrocracking-based bitumen upgrading uses energy to yield SCO of lower density and sulfur content than the bitumen. SCO imported from Western Canada accounts for an estimated 2-8% of total District 2 crude feeds and 2-12% of total District 4 feeds during 1999-2008. Refinery crude feeds and energy consumption do not reflect the original bitumen quality for this SCO or the energy consumed in its upgrading. The estimate shown in this table relates initial oil quality to process energy for total processing. The energy consumed and density and sulfur lost in upgrading is estimated based on process modeling data and added "back" to the refinery crude feed and energy consumption observed. The estimated total process energy is then compared to that predicted by the initial oil quality. Results suggest that in general, total process energy increases with worsening initial oil quality consistent with the prediction based on observed refinery data. The exception involves two results for District 4. This is discussed in note (k).

a. Refinery feed volume, density, sulfur content (*S*), capacity utilization, and products ratio (calculated as described in the main paper) are from data in Table S1.
b. Synthetic crude oil (SCO) inputs and sources by upgrader type are from the estimates detailed in Table S3. The volume, percentage of total refinery crude feed volume, and ratio of coking- to hydrocracking-based upgrading for the SCO are shown.
c. SCO was produced from bitumen in Western Canada by coking-based and hydrocracking-based upgrading *(S22)*. Both upgrading schemes typically also use atmospheric and vacuum

distillation and significant hydrotreating, sulfur recovery and hydrogen production. Material and energy inputs and outputs were estimated using process modeling of typical coking-based and hydrocracking-based upgraders yielding SCO from Athabasca bitumen by Keesom et al. *(S14)*. Modeled parameters included, among others, bitumen feed density (1.011 t/m^3) and sulfur content (48.64 kg/m^3), SCO yield (22,259 m^3/d), and SCO density and sulfur content for the coking-based (881.07 kg/m^3 *d,* 3.23 kg/m^3 *S*) and hydrocracking-based (921.82 kg/m^3 *d,* 3.23 kg/m^3 *S*) schemes. Carbon rejection, hydrogen addition and utility energy inputs estimated by process modeling on these parameters were 4,773 GJ/h for the coking-based scheme and 6,155 GJ/h for the hydrocracking-based scheme *(S14)*. This indicates energy inputs of approximately 0.04 GJ per kg density (including sulfur) lost from the feed in the SCO from the coking-based scheme, and 0.07 GJ/kg for that from the hydrocracking scheme. Energy inputs were not allocated to sulfur removal separately from density reduction in the reported results.

Bitumen feed to the coking- and hydrocracking-based schemes was modeled at 1.15 times and 0.97 times the SCO volume yield, respectively *(S14)*. Thus, on a product volume basis, estimated energy use was approximately 5.15 and 6.64 GJ per m^3 SCO produced for the coking- and hydrocracking-based upgraders, respectively. SCO from the coking- and hydrocracking-based schemes was 130.22 and 89.47 kg/m^3 lighter than the bitumen feed, respectively, and both schemes produced SCO with 45.41 kg/m^3 less sulfur than the bitumen feed. These estimates are applied to the shares of SCO from coking- and hydrocracking-based upgrading each year to estimate initial oil quality and total process energy. Notes d through f detail the calculations.

d. Density lost in upgrading the bitumen (Density_{add}) is added to the total refinery crude feed density to account for the bitumen input processed upstream to produce the SCO. Density_{add} is calculated as:

$\text{Density}_{add} = \text{SCOvol} \bullet (\text{DR} \div \text{VC})$

Where

SCOvol is the percentage of SCO in the total refinery crude feed; DR is the density reduction from bitumen from note (c) in kg/m^3; VC is the volume change from bitumen to SCO from note (c); and the result is in kg/m^3 refinery crude feed.

e. Sulfur lost in upgrading the bitumen (S_{add}) is added to the total refinery crude feed sulfur to account for the bitumen input processed upstream to produce the SCO. S_{add} is calculated as:

$S_{add} = \text{SCOvol} \bullet (45.41 \div \text{VC})$

Where

SCOvol is the percentage of SCO in the total refinery crude feed; 45.41 is the sulfur content reduction from bitumen from note (c) in kg/m^3; VC is the volume change from bitumen to SCO from note (c); and the result is in kg/m^3 refinery crude feed.

f. Energy lost in upgrading the bitumen (EI_{add}) is added to the refinery energy intensity calculated from the data in Table S1 (EI) to estimate the total energy intensity of processing the oil feed. EI_{add} is calculated as:

$EI_{add} = \text{SCOvol} \bullet \text{EC}$

Where

SCOvol is the percentage of SCO in the total refinery crude feed; EC is the energy consumed by upgrading in GJ/m^3 SCO from note (c); and the result is expressed as GJ/m^3 refinery crude feed.

g. Density_{adj} is the sum of crude feed density and Density_{add} and is an estimate of initial crude feed quality accounting for the bitumen feed upgraded to produce SCO refined.

h. S_{adj} is the sum of S and S_{add} and is an estimate of initial crude feed quality accounting for the quality of the bitumen feed upgraded to produce SCO processed in a refinery.

i. EI_{adj} is the sum of EI and EI_{add} and is an estimate of the total energy intensity of processing including upgrading and refining.

j. EI_{tp} is the total *predicted* energy intensity of upgrading and processing and is an estimate of the total energy intensity predicted by the relationship of EI to crude feed density and sulfur based on the refinery observations. EI_{tp} is the result from inputting S_{adj}, Density_{adj}, product ratio and capacity utilized to the prediction mode of the PLS model, which is run on the observations from districts 1, 2, 3 and 5. EI_{tp} is compared with EI_{adj} in the final column of the table (note k) and in Figure 2.

k. The final column of the table compares estimated total processing energy (EI_{adj}) with total processing energy predicted by initial oil quality (EI_{tp}). Dashed lines (--) show that the result for estimated energy falls within the 95% confidence of prediction for observations. Negative values (e.g., -1%) show the percentage by which any result falls below the 95% confidence of prediction. Positive values (e.g., 1%) show the percentage by which any result exceeds the 95% confidence of prediction.

Estimated EI_{adj} is within the prediction based on oil quality or within 3% of its confidence interval in 48 of 50 cases. The exceptions are excesses for the years 1999 and 2008 in District 4. These excesses can be attributed to high excess hydrogen production in District 4 during those years *(Table S4)*. It is possible that those high hydrogen values were

related to increased hydroprocessing needs for SCO, or for some other anomaly, in the District 4 crude feed during those years. The need for hydrogen addition to address the poor gas oil and distillate product qualities of SCO *(S24, S25)* and its variable quality *(S14, S24)* support this possibility. This possibility cannot be confirmed or excluded, because the SCO input volume is uncertain *(Table S3),* its quality is unknown, and there is a potential for other sources of variability in the poorly-mixed District 4 crude feed *(Table S2).*

Table S7. Contribution of CO_2 to CO_2e emitted by oil refineries.

	Units	CO_2	CH_4	N_2O
Refinery emissions mass				
Scope				
U.S. (NETL)	Mt/y	257.90	0.1656	0.0040
U.S. (EPA)	Mt/y	228.53	0.0873	0.0007
California	Mt/y	35.54	0.0015	0.0001
Global warming potential				
20-yr. horizon	Factor	1	62	275
100-yr. horizon	Factor	1	23	296
500-yr. horizon	Factor	1	7	156
20-yr. horizon CO_2e				
U.S. (NETL)	Mt/y	257.90	10.27	1.11
U.S. (EPA)	Mt/y	228.53	5.41	0.19
California	Mt/y	35.54	0.09	0.03
100-yr. horizon CO_2e				
U.S. (NETL)	Mt/y	257.90	3.81	1.19
U.S. (EPA)	Mt/y	228.53	2.01	0.21
California	Mt/y	35.54	0.03	0.03
500-yr. horizon CO_2e				
U.S. (NETL)	Mt/y	257.90	1.16	0.63
U.S. (EPA)	Mt/y	228.53	0.61	0.11
California	Mt/y	35.54	0.01	0.02
Range of percent total CO_2e				
20-yr. horizon	Percent	95.78-99.66	0.26-3.81	0.08-0.41
100-yr. horizon	Percent	98.10-99.82	0.10-1.45	0.08-0.45
500-yr. horizon	Percent	99.31-99.93	0.03-0.45	0.04-0.24

Legend and notes for Table S7. (Mt/y, megatons per year.) U.S. refinery emission estimates are reported as mass emitted (NETL) *(S25)* and as CO_2e emitted (EPA) *(S29)*. California refinery emissions are reported as mass emitted *(S30)*. Global warming potential is from the Intergovernmental Panel on Climate Change *(S31)*. The U.S. (EPA) emissions mass estimate is calculated from reported CO_2e *(S29)* and 100-year global warming potential *(S31)*. The percent of total CO_2e from CO_2 and the small differences between estimates shown in Table S7 support the finding that CO_2 dominates refinery greenhouse gas emissions.

Table S8. PLS inputs for CO_2 emissions predicted by *OQ,* and comparison emission estimates.
(NA, not applicable; value predicted by *OQ*)

PADD	Year	Density (kg/m^3)	Sulfur (kg/m^3)	Cap. utlzd. (%)	Prod. ratio (ratio)	Observed *EI* (GJ/m^3)	Predicted *EI* (95% conf.) Lower (GJ/m^3)	Central (GJ/m^3)	Upper (GJ/m^3)	Fuel mix em. intensity (kg/GJ)
1	1999	858.20	8.24	90.9	3.668	3.451	2.877	3.241	3.604	81.53
1	2000	860.18	8.00	91.7	3.489	3.430	2.987	3.349	3.711	80.34
1	2001	866.34	7.71	87.2	3.479	3.518	3.198	3.559	3.919	81.85
1	2002	865.71	7.45	88.9	3.605	3.426	3.152	3.511	3.870	81.08
1	2003	863.44	7.43	92.7	3.321	3.364	3.133	3.493	3.853	81.51
1	2004	865.44	7.79	90.4	3.398	3.416	3.209	3.568	3.927	81.46
1	2005	863.38	7.17	93.1	3.756	3.404	3.048	3.410	3.772	81.23
1	2006	864.12	7.17	86.7	3.522	3.440	3.054	3.417	3.780	80.40
1	2007	864.33	7.26	85.6	3.443	3.499	3.067	3.433	3.800	82.28
1	2008	863.65	7.08	80.8	3.400	3.551	2.972	3.352	3.733	83.26
2	1999	858.25	10.64	93.3	4.077	3.368	2.984	3.347	3.711	78.11
2	2000	860.03	11.35	94.2	4.132	3.361	3.104	3.468	3.832	77.56
2	2001	861.33	11.37	93.9	4.313	3.396	3.126	3.495	3.863	77.46
2	2002	861.02	11.28	90.0	4.345	3.393	3.068	3.432	3.796	77.90
2	2003	862.80	11.65	91.6	4.281	3.298	3.195	3.558	3.922	78.00
2	2004	865.65	11.86	93.6	4.167	3.376	3.369	3.733	4.098	77.25
2	2005	865.65	11.95	92.9	4.207	3.496	3.362	3.725	4.089	77.27
2	2006	865.44	11.60	92.4	3.907	3.738	3.380	3.738	4.095	75.84
2	2007	864.07	11.84	90.1	4.161	3.800	3.270	3.629	3.989	75.55
2	2008	862.59	11.73	88.4	4.333	3.858	3.154	3.515	3.875	74.97
3	1999	869.00	12.86	94.7	3.120	4.546	3.759	4.117	4.476	71.61
3	2000	870.29	12.97	93.9	3.120	4.563	3.813	4.172	4.531	71.87
3	2001	874.43	14.34	94.8	3.128	4.348	4.085	4.444	4.803	72.43
3	2002	876.70	14.47	91.5	3.251	4.434	4.140	4.499	4.859	72.71
3	2003	874.48	14.43	93.6	3.160	4.381	4.076	4.435	4.794	72.81
3	2004	877.79	14.40	94.1	3.228	4.204	4.213	4.572	4.930	73.43
3	2005	878.01	14.40	88.3	3.316	4.205	4.149	4.511	4.873	73.24
3	2006	875.67	14.36	88.7	3.176	4.367	4.067	4.432	4.798	74.15
3	2007	876.98	14.47	88.7	3.205	4.226	4.127	4.491	4.856	74.93
3	2008	878.66	14.94	83.6	3.229	4.361	4.165	4.540	4.915	74.48
5	1999	894.61	11.09	87.1	2.952	4.908	4.713	5.082	5.451	70.27
5	2000	895.85	10.84	87.5	3.160	5.189	4.725	5.092	5.460	69.09
5	2001	893.76	10.99	89.1	3.231	5.039	4.648	5.014	5.380	69.38
5	2002	889.99	10.86	90.0	3.460	4.881	4.450	4.814	5.178	69.15
5	2003	889.10	10.94	91.3	3.487	4.885	4.422	4.788	5.153	69.40
5	2004	888.87	11.20	90.4	3.551	4.861	4.410	4.775	5.140	69.89
5	2005	888.99	11.38	91.7	3.700	4.774	4.409	4.780	5.151	69.88
5	2006	887.65	10.92	90.5	3.615	4.862	4.331	4.695	5.060	69.32
5	2007	885.54	11.07	87.6	3.551	5.091	4.235	4.594	4.953	69.12
5	2008	890.16	12.11	88.1	3.803	4.939	4.456	4.824	5.191	68.39
Other inputs										
US	2002	873.89	12.32	90.7	3.534	NA	3.838	4.194	4.549	73.62
US	2005	875.08	12.43	90.6	3.597	NA	3.885	4.241	4.597	73.98
US	2006	873.78	12.32	89.7	3.458	NA	3.835	4.191	4.547	73.94
US	2007	873.89	12.50	88.5	3.485	NA	3.833	4.190	4.547	74.34
SFBA	2008	899.66	11.91	90.8	3.469	NA	4.938	5.307	5.676	68.39
Heavy oil		957.40	27.80	90.8	3.469	NA	8.228	8.795	9.363	73.77
Nat. bitumen		1 033.60	45.50	90.8	3.469	NA	12.266	13.200	14.135	73.77

Table S8. PLS inputs for CO_2 emissions predicted by *OQ,* and comparison emission estimates, *continued.*

PADD	Year	Central *EI* prediction (GJ/m^3)	Fuel mix em. intensity (kg/GJ)	Observed emissions (kg/m^3)	Predicted emissions (95% conf.) Lower (kg/m^3)	Central (kg/m^3)	Upper (kg/m^3)	Comp-arison (± % CI)
1	1999	3.241	81.53	281	243	265	287	––
1	2000	3.349	80.34	276	249	270	292	––
1	2001	3.559	81.85	288	257	279	301	––
1	2002	3.511	81.08	278	255	277	299	––
1	2003	3.493	81.51	274	254	276	298	––
1	2004	3.568	81.46	278	258	279	301	––
1	2005	3.410	81.23	277	251	272	294	––
1	2006	3.417	80.40	277	252	273	294	––
1	2007	3.433	82.28	288	251	273	295	––
1	2008	3.352	83.26	296	247	269	292	+1.4%
2	1999	3.347	78.11	263	249	271	292	––
2	2000	3.468	77.56	261	254	276	298	––
2	2001	3.495	77.46	263	256	277	299	––
2	2002	3.432	77.90	264	253	274	296	––
2	2003	3.558	78.00	257	259	280	301	-0.5%
2	2004	3.733	77.25	261	267	288	309	-2.2%
2	2005	3.725	77.27	270	266	288	309	––
2	2006	3.738	75.84	284	267	289	310	––
2	2007	3.629	75.55	287	262	284	306	––
2	2008	3.515	74.97	289	256	279	301	––
3	1999	4.117	71.61	326	285	307	328	––
3	2000	4.172	71.87	328	287	309	331	––
3	2001	4.444	72.43	315	300	321	342	––
3	2002	4.499	72.71	322	302	323	345	––
3	2003	4.435	72.81	319	299	320	342	––
3	2004	4.572	73.43	309	305	326	348	––
3	2005	4.511	73.24	308	302	324	345	––
3	2006	4.432	74.15	324	299	320	341	––
3	2007	4.491	74.93	317	301	322	344	––
3	2008	4.540	74.48	325	303	325	346	––
5	1999	5.082	70.27	345	328	350	372	––
5	2000	5.092	69.09	358	329	351	373	––
5	2001	5.014	69.38	350	325	347	369	––
5	2002	4.814	69.15	338	317	338	360	––
5	2003	4.788	69.40	339	315	337	359	––
5	2004	4.775	69.89	340	315	336	358	––
5	2005	4.780	69.88	334	315	337	358	––
5	2006	4.695	69.32	337	311	333	354	––
5	2007	4.594	69.12	352	307	328	350	+0.5%
5	2008	4.824	68.39	338	317	339	361	––
Other inputs								
US	2002	4.194	73.62	315	288	309	331	––
US	2005	4.241	73.98	285	290	311	333	-1.7%
US	2006	4.191	73.94	277	288	309	330	-3.9%
US	2007	4.190	74.34	280	288	309	330	-2.6%
SFBA	2008	5.307	68.39	360	338	360	383	––

Legend and notes for Table S8.

Table S8 shows inputs for emissions predicted by crude feed quality and compares the predictions with observed or estimated emissions. Observed crude feed density and sulfur, capacity utilized and products ratio were compared with observed *EI* among districts and years. Predicted *EI* values are the results from this PLS analysis, and are shown for the central prediction and the 95% confidence of prediction for observations. The central *EI* prediction and the observed fuel mix emission intensity were then compared with observed emissions among districts and years. Predicted emissions are the results from this PLS analysis, and are shown for the central prediction and the 95% confidence of prediction for observations. The observations compared among districts and years are from the data in Table S1. Other inputs shown at the bottom of the table were used in the prediction mode of these PLS models.

For U.S. refineries in 2002, 2005, 2006 and 2007, all data except estimated annual emissions are from Table S1. USEIA estimated that U.S. refineries emitted 277.6 megatons (Mt) of CO_2 in 2002 *(S32)*. The National Energy Technology Laboratory estimated that U.S. refineries emitted 257.9 Mt in 2005 *(S12)*. USEIA estimated that U.S. refineries emitted 250.7 Mt in 2006 and 251.3 Mt in 2007 *(S33)*. U.S. refinery crude feed volumes in 2002, 2005, 2006 and 2007 totaled $241.3 \cdot 10^4$, $247.7 \cdot 10^4$, $248.0 \cdot 10^4$ and $245.6 \cdot 10^4$ m^3/day respectively *(Table S1)*.

OQ inputs for San Francisco Bay Area (SFBA) refineries in 2008 were estimated as detailed in Table S9. The domestic component of SFBA crude feeds was more limited and better characterized than that of refinery crude feeds statewide, and this allowed a more reliable *OQ* estimate for SFBA refining than that which could be derived from publicly reported data for California refineries statewide. Although it has less capacity than Southern California, the SFBA has greater total crude capacity than other refining centers in District 5 *(S7)*. The District 5 fuel

mix during 2008 is used for the SFBA prediction to account for fuel mix differences observed among districts *(Table S1)*. SFBA inputs for capacity utilized and products ratio were the US averages for 1999-2008 from Table S1. Third party-certified estimates of emissions from SFBA refineries and adjacent plants supplying them hydrogen, as reported by the California Air Resources Board *(S34),* total 17.18 Mt in 2008. Crude feed volume was estimated as the total crude capacity of SFBA refineries in 2008 ($13.07 \cdot 10^4$ m^3/day) reported by *Oil & Gas Journal (S7)*. This SFBA emissions estimate (360 kg/m^3) compares with estimated California emissions of 354 kg/m^3 based on estimated emissions (36.88 Mt) and crude feed volume ($28.5 \cdot 10^4$ m^3/day) for refineries statewide in 2008 *(S34, S35)*.

The California Air Resources Board *(S36, S37)* reported estimated CO_2 emissions from refining the average crude feed in California, including those from bulk vents and refinery fuels acquisition, of 13.34 g/MJ gasoline (CARBOB) and 11.19 g/MJ diesel (ULSD) for 30.10 GJ/m^3 gasoline and 33.86 GJ/m^3 diesel. The California Energy Commission *(S35)* reported 2008 California refinery crude inputs, gasoline (RBOB, CBOB) yield, and diesel (≤ 15 ppm sulfur) yield of 104.04, 51.11 and 21.61 $m^3 \cdot 10^6$ respectively (total gasoline and diesel yield was 61.05 and 23.06 $m^3 \cdot 10^6$ respectively). These reports suggest refinery emissions of 197.2 and 78.7 kg/m^3 crude refined for California-grade gasoline and diesel production, respectively.

OQ inputs for heavy oil and natural bitumen are the average densities and sulfur contents of heavy oil and natural bitumen reported by the U.S. Geologic Survey *(S17)*. Other inputs for heavy oil and natural bitumen assume the 1999-2008 U.S. averages based on the data from Table S1. The 1999-2008 fuel mix assumption may be conservative for future emissions from refining lower quality oil, which tends to create more byproduct gases and petroleum coke that could

replace some of the natural gas now burned as fuel. Refinery emissions observations were not available for these oils.

The columns on the right of the table compare predicted and observed emissions. Horizontal lines (—) indicate that the result is within the 95% confidence of prediction. Emissions observed among districts and years vary consistently with those predicted by *OQ,* fall within the 95% confidence of prediction in 36 of 40 cases, and fall within 3% of the confidence of prediction in all cases. Emissions estimated by government agencies fall within the prediction in 2 of 5 cases and fall within 4% of its confidence interval in all cases. The agency estimates differ from each other by 12% to 30% while they differ from the central prediction based on *OQ* by 0.1% to 10%.

Table S9. Estimate calculation, San Francisco Bay Area crude feed *OQ* in 2008.

Crude feed vol. (m^3/d)	Foreign[a]	SJV[b]	ANS[c]	Subtotal[d]
Benicia Plant	$8.870 \cdot 10^3$	$5.323 \cdot 10^3$	$7.987 \cdot 10^3$	$2.218 \cdot 10^4$
Golden Eagle Plt.	$9.683 \cdot 10^3$	$7.987 \cdot 10^3$	$7.930 \cdot 10^3$	$2.560 \cdot 10^4$
Martinez Plt.	$4.837 \cdot 10^3$	$1.992 \cdot 10^4$	$4.592 \cdot 10^2$	$2.522 \cdot 10^4$
Richmond Plt.	$2.992 \cdot 10^4$	0	$8.710 \cdot 10^3$	$3.863 \cdot 10^4$
Rodeo/S. Maria Plt.	$1.611 \cdot 10^3$	$1.450 \cdot 10^4$	$2.968 \cdot 10^3$	$1.908 \cdot 10^4$
Crude feed mass (kg/d)	Foreign[a]	SJV[e]	ANS[f]	Total
Whole crude	$4.827 \cdot 10^7$	$4.540 \cdot 10^7$	$2.392 \cdot 10^7$	$1.176 \cdot 10^8$
Sulfur in crude	$7.592 \cdot 10^5$	$5.901 \cdot 10^5$	$2.076 \cdot 10^5$	$1.557 \cdot 10^6$
		OQ	*S* (kg/m^3)	**11.91**
			d (kg/m^3)	**899.66**

Legend and notes for Table S9.

The *OQ* input for the San Francisco Bay Area refineries prediction (*S* and *d, Table S8)* is an estimate based on crude feed from foreign, Alaskan North Slope (ANS) and California oils that assumes transport logistics result in California supply from San Joaquin Valley crude delivered by pipeline (SJV) *(S16, S38)*. SJV portions of refinery feeds *(S39)* are used with refinery capacities *(S7)* and foreign crude feed volumes *(S40)* to estimate SJV volume processed. ANS volume is then estimated by difference. Weighted average crude feed *OQ* is estimated using these feed volumes and foreign *(S40),* SJV *(S38, S41)* and ANS *(S42)* crude quality data. Superscript notes in Table S9 identify the usage of these data in the estimate calculation specifically:

(a) Foreign crude feed volume, density and sulfur content reported for each plant *(S40)*.

(b) San Joaquin Valley pipeline crude volume based on SJV percentage of refinery feed reported *(S39)* and crude charge capacities *(S1)*.

(c) Alaskan North Slope (ANS) volume estimated by difference.

(d) Refinery crude charge capacities from *Oil & Gas Journal (S7)*.

(e) Based on SJV volume processed by Bay Area refineries, weighted average density (951.0 kg/m^3) from available data *(S38),* and sulfur content (12.36 kg/m^3) *(S41)*.

(f) From ANS volume calculated, and density (860.18 kg/m^3) and sulfur content (7.40 kg/m^3) of ANS crude at the Richmond Plant *(S42)*.

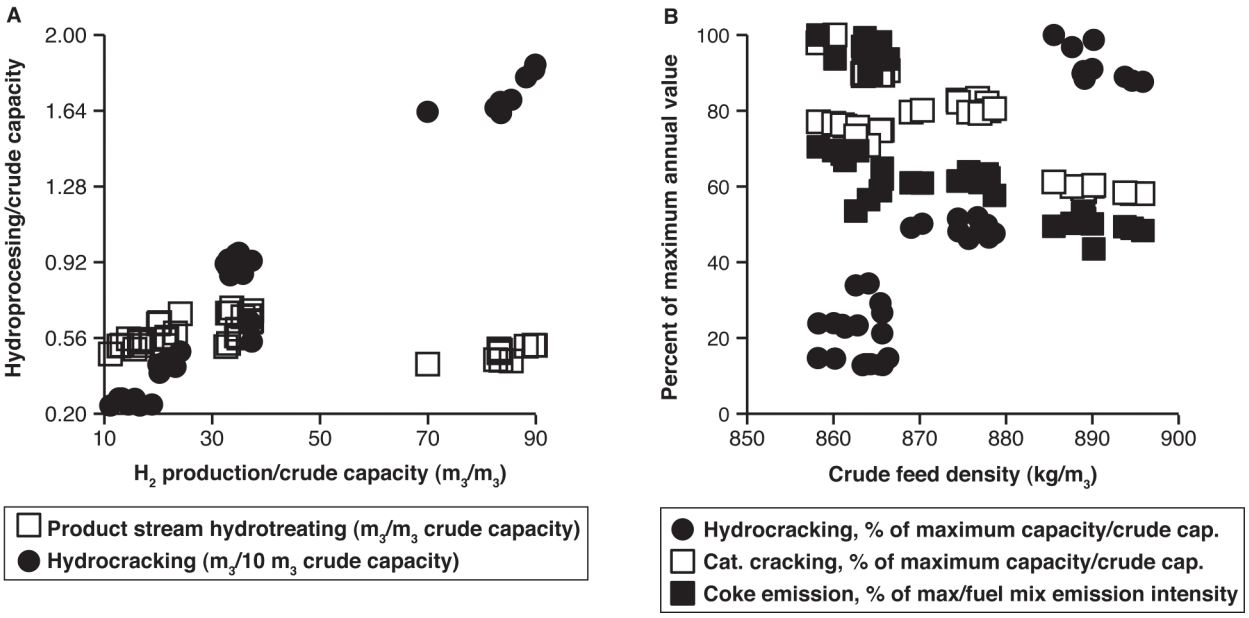

Figure S1. Some shifts among hydrogen addition and carbon rejection technologies affecting relationships between (A) hydrotreating and hydrogen production, and (B) fuel mix emission intensity and crude feed density, across refining districts 1, 2, 3 and 5, 1999-2008. All observations shown are from the data in Table S1.

A. Decreasing hydrotreating/hydrocracking ratio with increasing hydrogen production. Capacities are shown per volume atmospheric crude distillation capacity. Hydrocracking capacities are much smaller than total hydrotreating capacities and are shown at ten-times scale to reveal trends for both types of hydroprocessing. Hydrocracking uses much more hydrogen per volume oil feed than hydrotreating *(S43),* though actual unit H_2 requirements vary by type and quality of feed, unit design, catalyst type and condition, firing rate and quench rate of process units. Hydrocracking increases steadily with hydrogen production while product hydrotreating does not. Hydrotreating increases with H_2 production at lower H_2 production but is lowest at highest H_2 production. Relative to hydrocracking capacity, hydrotreating capacity decreases steadily with increasing H_2 production, from the largest capacity relative to hydrocracking in

District 1 (H_2 capacity 13-19 m^3/m^3 crude capacity) to the smallest relative to hydrocracking in District 5 (H_2 capacity 69-90 m^3/m^3).

B. Decreasing petroleum coke contribution to total fuel mix emissions with increasing crude feed density. The portion of total fuel mix emissions accounted for by petroleum coke and the process capacities/volume crude capacity are shown as percentages of the maximum (100%) for each value. The observed increase in hydrocracking with density is consistent with the strong positive associations of hydrogen production with both hydrocracking and density *(Table 1, main text)*. Coke accounts for a decreasing portion of fuel mix emissions as crude feed density and hydrocracking increase. This change for coke, which has higher emission intensity than other major refinery fuels, can explain why the fuel mix emission intensity decreases slightly with worsening oil quality *(Table S1)*. Despite increasing total conversion capacity (hydrocracking, catalytic cracking, and thermal coking), catalytic cracking capacity per vol. crude capacity decreases as crude feed density and hydrocracking increase. The ratio of catalytic cracking to hydrocracking decreases across districts, following the hydrotreating pattern noted above. Decreasing catalytic cracking explains decreasing coke emissions because cracking catalyst regeneration is a major cause of coke combustion in refineries.

The shifts from hydrotreating and catalytic cracking to hydrocracking observed can explain the coincidence of slightly lower hydrotreating at high hydrogen production, and of slightly decreasing fuel mix emission intensity as crude feed density increases, for these districts and years. Refiners can choose to substitute hydrocracking for hydrotreating and catalytic cracking to some extent, but the relative importance of crude feed quality among the factors that influenced such business decisions is beyond the scope of this study.

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CARBON FOOTPRINTING

Factors driving refinery CO_2 intensity, with allocation into products

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Abstract
Background and scope Attempts to develop adequate allocation methods for CO_2 emissions from petroleum products have been reported in the literature. The common features in those studies are the use of energy, mass, and/or market prices as parameters to allocate the emissions to individual products. The crude barrel is changing, as are refinery complexities and the severity of conversion to gasoline or diesel leading to changes in the emissions intensity of refining. This paper estimates the consequences for CO_2 emissions at refineries of allowing these parameters to vary.
Materials and methods A detailed model of a typical refinery was used to determine CO_2 emissions as a function of key operational parameters. Once that functionality was determined, an allocation scheme was developed which calculated CO_2 intensity of the various products consistent with the actual refinery CO_2 functionality.
Results The results reveal that the most important factor driving the refinery energy requirement is the H_2 content of the products in relation to the H_2 content of the crude. Refinery energy use is increased either by heavier crude or by increasing the conversion of residual products into transportation fuels. It was observed that the total refinery emissions did not change as refinery shifted from gasoline to diesel production.
Discussion The energy allocation method fails to properly allocate the refinery emissions associated with H_2 production. It can be concluded that the reformer from a refinery energy and CO_2 emissions standpoint is an energy/CO_2-equalizing device, shifting energy/CO_2 from gasoline into distillates. A modified allocation method is proposed, including a hydrogen transfer term, which would give results consistent with the refinery behavior.
Conclusions The results indicate that the refinery CO_2 emissions are not affected by the ratio of gasoline to distillate production. The most important factors driving the CO_2 emissions are the refinery configuration (crude heaviness and residual upgrading) which link to the refinery H_2 requirement. Using the H_2-energy equivalent allocation proposed in this study provides a more reliable method to correctly allocate CO_2 emissions to products in a refinery in a transparent way, which follows the ISO recommendations of cause-effect and physical relationship between emissions and products.
Recommendations and perspectives Regulatory activity should recognize that there is no functional relationship between refinery CO_2 emissions and the production ratio of gasoline, jet, and diesel, and adopt a methodology which more accurately mirrors actual refinery behavior.

Keywords CO_2 allocation methods · Carbon footprint · Crude oil refining CO_2 emissions · Diesel production · Energy-consuming products · Gasoline production · H_2 effects on refinery CO_2 · Life cycle assessment · Refining emissions

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1 Background, aim, and scope

Policy makers and regulators are seeking to impose greenhouse gases (GHG) performance standards on fuel lifecycles, e.g., California's Low Carbon Fuel Standard (LCFS 2007) and the European Union's Fuels Quality and Renewables Directives (COD 2008). The common feature of these regulations is that fuel providers will be required to track the lifecycle (i.e., well to wheels) GHG emissions intensity of their products, measured per unit of fuel energy, and reduce this value over time. Furthermore, the US Environmental Protection Agency is assessing fuel lifecycle GHG emissions intensities for the Energy Information and Security Act. Models describing emissions in the fuel lifecycle, which were designed to meet academic scenario forecasting needs, now have to be redesigned to suit regulatory applications, with the associated legal and commercial implications.

Crude oil based transport fuels are produced concurrently with other fuel and non-fuel products. Consequently, overall CO_2 emissions generated by the refining process can be distributed between the individual products through "allocation" rules. Historically, such rules have reflected the scope and goals of the study, the modeler's understanding of the process, the available data and end-use options for the products because there is no theoretical basis for choosing one allocation scheme over another. When some refining products are regulated on their carbon content but not others, it is important to ensure that the allocation rules reflect the actual climate impacts of the regulated products as fairly as possible, whilst at the same time, minimizing incentives to transfer responsibility for the impacts onto unregulated products.

The International Standard Organization (ISO) guidelines for lifecycle assessment (LCA) recommend that allocation should be avoided wherever possible, but where this is not possible, the allocation should reflect quantitatively or qualitatively how environmental impact changes with product yield. Some authors have suggested options to refine the ISO methodology and the accuracy of the results (Ekvall and Finnveden 2001). Ultimately, however, it is left to the LCA practitioner to decide how to follow these recommendations. As a result, the literature contains several different estimates for the carbon intensity of gasoline and diesel production even for similar systems (Furuholt 1995).

The problems faced in solving the issue of allocation in multi-product systems are fairly well known, and they have been extensively discussed in the literature (Azapagic and Clift 1999; Ekvall 1999; Babusiaux 2003; Ekvall and Weidema 2004). Different accounting schemes have been proposed to assign emissions to the plant products typically based on mass, energy, or market value shares of products. More recently, linear programming (LP) models, which have a long tradition in the refining industry (Charnes et al. 1952; Griffin 1972; Palmer et al. 1984), have been extended to calculate CO_2 emissions, and to assign individual product contributions to the CO_2 emissions in refineries through a marginal approach (Azapagic and Clift 1999; Babusiaux 2003). These models follow a similar logic to that used in assigning costs to refinery products: global CO_2 emissions are allocated to products based on the incremental CO_2 emissions generated in manufacturing an additional volume of the products. The resulting product CO_2 intensities are sometimes, but not always, different from those estimated under traditional mass/energy allocation schemes. Neither type of method is superior; but each has its domain of validity and applicability.

Furuholt (1995) compared the energy consumption and pollutant emissions in the production and end use of regular gasoline, gasoline with MTBE, and diesel. Energy consumption and emissions were tracked through the production chain and emissions were allocated to products based on their energy content. The results were highly sensitive to the product specifications, and it was predicted that emissions from diesel production were significantly lower than those from production of gasoline as a consequence of "diesel's lower process energy requirement".

Wang and coworkers (Wang et al. 2004) compared the impact of different allocation rules applied at the process unit level in a US refinery. They used as an archetype refinery a detailed quantitative process-step model of petroleum refining developed in the late 1970s at Drexel University (Brown et al. 1996). The mass and energy balances at each process step of this archetype constitute the reference process-step model for petroleum refineries (Ozalp and Hyman 2007). Wang et al. (2004) compared the use of mass, energy content, and market value share of final and intermediate petroleum products as allocation weight factors at the process unit and the refinery levels. They defined product energy intensities for major refinery products (defined as the fraction of process energy invested in producing a particular product relative to its weight factor), and concluded that wherever possible, energy use allocation should be made at the lowest sub-process level (Wang et al. 2004). They found diesel production to be less energy intensive than gasoline production in each of the allocation weighting methods used (mass/energy/market value; refinery/process unit level) as predicted by Furuholt (Furuholt 1995).

Tehrani (Tehrani 2007) used an LP model to study the CO_2 emissions allocation problem for a European price-taking refinery operating in a cost-minimizing environment. It was assumed that the refiner's objective is to satisfy a petroleum production target at the minimum cost and subject to constraints of prevailing technology, commodity prices, input availabilities, oil product demand, capacity

constraints, material balance, and product quality. Tehrani concluded that emissions could be allocated among products using "average allocation" coefficients containing two contributions, a direct one, which is its marginal CO_2 intensity, and an indirect contribution, which depends upon the production elasticity of unit processes and is calculated at the LP optimal solution ex-post. This approach was later used (Tehrani and Saint-Antonin 2007) to assess the impact of reducing sulfur in European automotive fuels on the refining emissions intensity of gasoline and diesel. It was shown that, contrary to prior results (Furuholt 1995; Wang et al. 2004), gasoline refining could be less emissions intensive than diesel refining.

Pierru (2007) used an alternative LP optimization function including operating costs and cost associated with the refinery's CO_2 emissions to calculate the marginal emissions (in accordance with economic theory) from the various refinery products. The study highlights the impact of constraints such as demand, refinery capacity, and raw material supply on the CO_2 emissions originated at refineries. It was concluded that contrary to traditional LCA studies, diesel has a higher marginal contribution to refinery emissions than gasoline.

The common features in the above studies, notwithstanding the different approaches, constraints, and results are: single-fixed refinery configuration, fixed unit throughput capacities and fixed crude diet.

The crude barrel is changing, as are fuel specifications, and these will lead to changes in refining emissions intensities. In this paper, we therefore focus on the consequences of varying the crude diet, the severity of conversion to gasoline or diesel, and the complexity of the refinery. The critical element is the hydrogen requirement, since its production and consumption is highly carbon intensive. A detailed analysis of the hydrogen flow through the refinery is carried out at each refinery unit, in order to establish the carbon footprint of products. Based on this work, we propose a more realistic way to estimate the energy and emissions intensities of refinery products.

2 Materials and methods

The refinery simulation model is a case study model used by Shell to select crude type, determine refinery products, and calculate refinery economics for major investment decisions. Shell has high confidence in its accuracy.

Yield representations reflect crude boiling curve, hydrogen content, aromaticity, sulfur, nitrogen, and other relevant parameters associated with the refinery crude diet. Several of those terms (boiling curve, hydrogen content, and aromaticity) are at least partially covariant with crude density (API gravity), but it is more accurate to handle them individually. Processing severity can be adjusted by distributing feeds differently within the refinery flow matrix, by changing reactor severity of individual processes, and by varying fractionator cut points. Energy consumption was determined by summing feed-rate-based consumption factors for each process unit (some of which are functions of that unit's severity). Feed gas and fuel gas energy for H_2 manufacture are included. Hydrogen balance is maintained throughout the model, meaning the hydrogen contained in all feeds equals the hydrogen contained in all products from each unit. Relatively few refinery models have that feature; meaning that their prediction of how much hydrogen is required from the hydrogen plant is less reliable. Since hydrogen plant size is critical to refinery CO_2 emissions, this is an important advantage for this study.

Specific process units included were: crude distillation, delayed coking, fluid catalytic cracking, hydrocracking, naphtha reforming, alkylation, hydrotreating (naphtha, distillates, fluid catalytic cracking (FCC) feed), hydrogen manufacture, sulfur recovery, and various other enabling process units typically included in a refinery (the refinery flow chart is available as Online Resource 1).

Product specifications were gasoline was US reformulated gasoline in a typical grade mix of regular to premium. Diesel was US ultra low sulfur diesel. Jet was Jet-A, and in cases where produced, residual was US Gulf Coast high sulfur Fuel Oil #6. Naphtha from the catalytic cracker was hydrotreated such that gasoline pool sulfur was 25 ppm. Jet smoke and diesel cetane number using a normal severity distillate hydrotreating unit were inside fuel specifications for all except two of the crudes analyzed. This was ignored because real refineries have some scope to blend streams to meet specifications, and if not, the refinery would run a blend of crude rather than neat crude. The three low value residual streams (Cat slurry, Fuel Oil #6 and Coker Coke) were summed into a single product class called residual/coke. To summarize, the product streams considered were liquefied petroleum gas (LPG), gasoline, distillate (including gasoil and kerosene), and residual/coke.

It was considered critical that the results from the allocation methods and the results from the model runs be consistent. In other words, if the refinery runs showed no difference in total refinery CO_2 emissions as the gasoline to diesel ratio was varied, then the CO_2 intensity of those two fuels should be the same.

3 Results

Three issues were studied explicitly: crude heaviness (fraction boiling >1,000°F/540°C), production ratio of gasoline to distillates, and whether the refinery processed

its 1,000°F/540°C+vacuum resid in a delayed coker or blended it to Fuel Oil no. 6. Issues such as ratio of FCC to hydrocracking capacity, the type of benzene production controls employed, whether C_5/C_6 isomerization is employed, in cases with residue reduction, whether the residue reduction unit was a delayed coker, other type of coker, or other type of unit such as LC-Finer or resid hydrotreater, and any number of similar configurational issues could perturb the numerical results. Pair cases simulations (base Vs base + δ), where δ refers to a perturbation on the variable under analysis were run to assess the robustness of the results and to ensure that they did not have a material impact on the conclusion reached through the study

3.1 Matrix of cases

Crude heaviness was studied by selecting six crudes with quantity of vacuum bottoms (>550°C) ranging from 10% to 35% (lightest Brent, heaviest Maya). Production ratio of gasoline to distillate was varied by shifting from gasoline to distillate mode which means lowering FCC and HCU reactor severities, and changing cut points at crude unit, cat cracker, and hydrocracker. Cut points were shifted on both ends, lowering naphtha/distillate cut point and raising distillate to FCC feed cut point. Production of resid was changed by shutting down the coker, and sending coker feed to #6 oil blending instead. Case names of these conditions were captured in a four character code. The first character was either K or 6, representing a coker case or a case that produced #6 residual fuel oil. The second and third characters were C for crude, and a number, meaning the crude heaviness choices from 1 to 6. The final case was H or L meaning high or low severity to gasoline. So for example, KC3L was a coker case on crude 3, with low severity to gasoline. Or case 6C5H was a #6 fuel oil case on crude 5 with high severity to gasoline. In all, the refinery was run in four modes (high/low gasoline, with/without coker) with six different crudes to produce a matrix of 24 data points. For each case, refinery yields and fuel/CO_2 data were generated. Refinery yields data are available as Online Resource 2. The fuel/CO_2 data were split by process needs and H_2 generation needs.

One aspect of these runs was different from typical model running strategy. In most model studies, one must stay within capacity constraints of the various process units. But in this study, there are wide variations of crude heaviness, which would far exceed the acceptable flow rate variations for individual units in any given refinery. So individual process unit throughputs were allowed to vary as needed, such that each intermediate stream in the refinery headed to its normal consuming unit. Had that not been done, the results would have been strongly and inappropriately biased by internal constraints. This way, it was as though each case had a custom tailored refinery to allow ideal flows for that case.

3.2 Numerical results

Consider the results as being four blocks of data, with six cases in each block. The four blocks are with/without coker (i.e., high/low resid production), high/low conversion to gasoline, and within each of those four blocks, the six crudes of varying heaviness. These four blocks are shown in Fig. 1.

Comparing the left two with the right two blocks on Fig. 1 shows that adding the coker to eliminate the no. 6 fuel oil production clearly increases CO_2 emissions for all case pairs involving that switch. Not only does the coker consume energy in its own right, it upgrades a low hydrogen content product stream (no. 6 fuel oil). This in turn requires the refinery to run other cracking and hydrogen consuming units harder to boost the hydrogen content up from resid hydrogen levels (because resid is no longer being produced) to mogas/jet/diesel hydrogen levels (because those higher hydrogen content products are being produced instead of resid).

Changing the severity and cut points to vary the ratio of gasoline to distillate has very little effect in any of the cases in any of the case pairs where that change was made (see Fig. 1). At first, this might seem illogical because to go to lower boiling point gasoline, the level of cracking needed is harder, and that would seem to require more energy. The counter-balancing point is H_2 content. In gasoline production, aromatics are favored due to higher octane ratings and this is where the reformer's H_2 production comes into play. To make more gasoline, reformer feed rate increases and as reformers also produce H_2, the amount of H_2 that must be made in the CO_2 intensive H_2 plant decreases, and on balance, the overall CO_2 emissions do not change very much. In contrast, for jet and diesel production, paraffins are favored. In fact, despite its lower boiling point, H_2 content of gasoline is similar to jet and diesel.

What happens with crude heaviness depends on whether there is a coker (or other residue reduction unit). The left two blocks of Fig. 1 show that if there is a coker to eliminate resid, heavier crude needs a bigger coker, which consumes more energy, and demands more hydrogen consumption in downstream units, thus increasing CO_2 emissions (from running the hydrogen plant at a higher rate). The right two blocks of Fig. 1 show that without a coker, the refinery produces resid as a product, so CO_2 emissions do not change very much with crude heaviness. However, the heavier crude makes more resid in comparison to transportation fuel, and that is an indirect CO_2 penalty because more carbon intensive resid product fuels

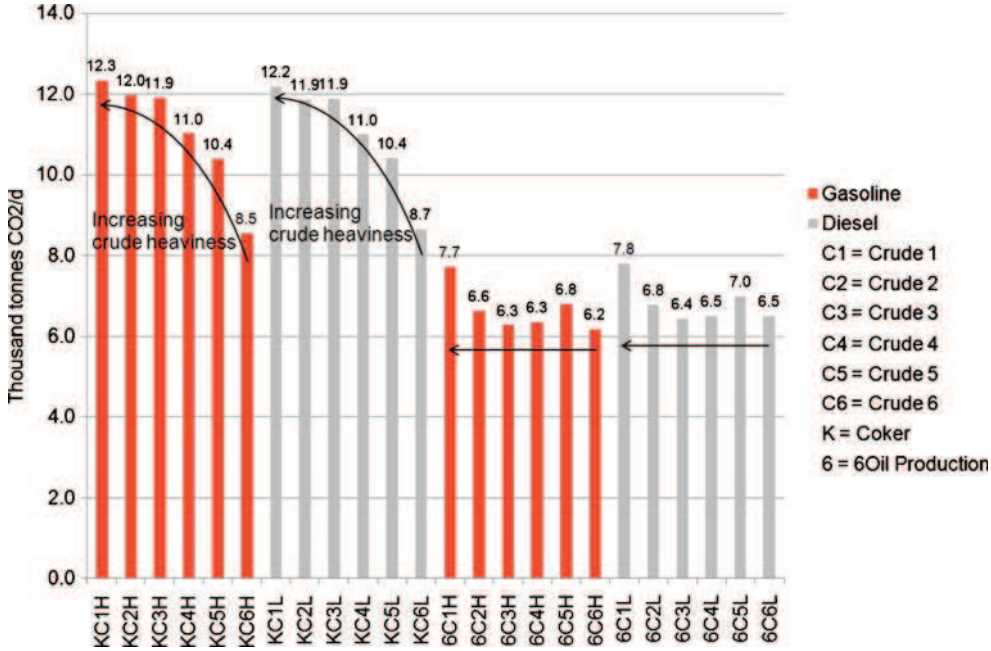

Fig. 1 Overall refinery CO_2 emissions

are being produced. Note that this issue of with/without coker, or higher/lower residual fuel production is sometimes referred to as refinery complexity. The coker (or other residue reduction unit) adds complexity not only because it is an added large process unit, but also because products from residue reduction units are low quality, which requires other units within the refinery to be larger and higher severity in order to upgrade them.

The fact that CO_2 emissions are practically independent of light product ratio shifts from gasoline to diesel shows that the CO_2 emissions at refinery level are not driven by the differential energy demands of these products, but by other factors: crude heaviness and whether the refinery has a coker to eliminate production of residual fuel. A third route to CO_2 emissions reductions is energy conservation; all routes can be influenced by external issues such as crude availability, product demands, and prices.

4 Discussion

It was shown in Section 3 that two operational routes significantly lowered total refinery CO_2 emissions. The production ratio of gasoline to diesel fuel was not one of those factors, because interaction of some non-obvious hydrogen issues equalizes the total refinery CO_2 emissions from production of gasoline and diesel fuel. The hydrogen balance at the refinery, together with the results from tracking products through process units in terms of the energy consumed during their production and their associated CO_2 emissions are described in the next sections. Both results are used to develop an allocation strategy consistent with refinery CO_2 emissions behavior.

4.1 Hydrogen balance

One of the most critical factors in refining is hydrogen balance. This is not just hydrogen balance in the sense of flows of elemental hydrogen gas as a processing stream but also the hydrogen content of feeds and products. Since crude oil is generally low in hydrogen content, and refined products (except for residual fuel and coke) are high in hydrogen content, refineries are forced to produce the additional H_2 that satisfies their needs in a process that its intrinsically highly CO_2 emissions intensive.

Carrying this hydrogen issue a bit further, if the crude has less hydrogen coming in (most common explanation being that it is heavier), or the products have more hydrogen going out (most common explanation being more transportation fuel with correspondingly less residual fuel), the refinery energy consumption will invariably be higher. While it is true that there are many possible routes and configurations of refineries (for example, cat cracking versus hydrocracking), all refineries by all routes are bound by this hydrogen balance issue. The exact configuration of a refinery can cause minor variations in energy/CO_2, but the simple difference in hydrogen content between crude coming in and products going out are by far, the controlling factor.

In a typical refinery, roughly half of the H_2 is produced as a by-product from the catalytic reformer (and in the few refineries that have them, from the olefins plant) (NETL 2008). Most allocation schemes allocate the energy and CO_2 from the "on purpose" H_2 plant properly, but they ignore the impact of the reformer H_2, and if applicable, from the H_2 produced at the olefins plant. Ignoring the reformer H_2 production means that the H_2 consuming units

get a substantial part of their H_2 requirements as a CO_2-free stream, and also that the reformer is not credited for the large CO_2 avoidance associated with its H_2 production and the displaced H_2 from the "on purpose" H_2 plant.

Production of gaseous H_2 in "on purpose" H_2 plants can be typically characterized by a well to tank footprint of circa 108 gCO_2e/MJ (GREET 2008). By comparison, the gasoline footprint is around 90 gCO_2e/MJ in GREET. This highlights the importance of correctly accounting for CO_2 emissions in processes involving hydrogen production.

If one looks at what drives hydrogen content of crude, it is mostly the heaviness, i.e., how much boils above 1,000°F/540°C. There is a modest added effect for whether the crude is of naphthenic or paraffinic character, but heaviness is more important. One would expect that the heavier the crude, and thus the less hydrogen that the crude contains, the higher the energy requirement and CO_2 intensity of the refinery.

On the product side, gasoline, jet, and diesel have roughly equivalent hydrogen content: For the main transport fuels[1], the C/H ratio would range for gasoline (EN220) ~1.7–1.9, for diesel (EN590) ~1.7–1.9 and for jet A-1 (AFQRJOS[2]) ~1.7–1.9. The mass ratio (carbon to hydrogen) estimated for these fuels range between 6.3 and 6.9 m/m for all of them (see footnote 1). It might seem logical to think that gasoline should have more hydrogen than jet or diesel because it has a lower boiling temperature range, and hydrogen content is normally higher as boiling point gets lower. But actually, because quality issues force a bias toward aromatic species for gasoline to maintain its octane rating, while at the same time there is an opposite bias toward paraffinic content for jet and diesel to maintain their smoke point and cetane ratings things balance out in such a way that the main transportation fuels are similar in hydrogen content, and thus should be similar in their CO_2 emissions intensity.

LPG (generally C_3 and C_4 molecules) contains more hydrogen than gasoline, jet, and diesel, so should have higher CO_2 intensity. Some might think LPG should be low CO_2 intensity since much of it comes from simple fractionators. But LPG is not an "on-purpose" product, it is a byproduct. If more LPG were made by choosing catalysts that did more overcracking, the LPG would carry away more hydrogen in the product, requiring more refining and hydrogen manufacturing energy.

By contrast to high hydrogen LPG, residual fuel oil has very low hydrogen content. Resid can either be produced by the refinery as a product, or cracked in a resid cracking unit such as a coker. Coking is energy intensive, not only because of the coker itself, but also because the coker makes hydrogen deficient products which need extra hydrogen to be added in subsequent refining steps. Allowing the resid to go out as residual product rather than cracking it to lighter products saves large amounts of energy, thus making resid a very low energy product.

While not explicitly studied in the model runs described in this paper, other factors can influence refinery CO_2 emissions. One example has already been mentioned, namely, energy conservation which would lower CO_2 emissions. Others would include product specification changes such as lower sulfur or lower aromatics, which would raise CO_2 emissions. And finally, going to production ratios of products outside "normal ranges" could negate the conclusion that all of the light transportation fuels have "roughly equal" CO_2 emissions. If a refinery is forced to make more of a particular fuel than can be accommodated within "natural refinery flexibility" (such as very high diesel production, with very low gasoline production), CO_2 emissions would clearly increase. Variations in production ratios modeled in this paper were all within normal ranges of refinery flexibility, with an average swing between gasoline and diesel for high to low gasoline cases of around 4% on crude, and ranged between 2% and 6% depending on crude type and refinery configuration.

Subject to these caveats, we might expect that the refinery production of CO_2 (i.e., consumption of fuel, including the fuel needed to manufacture hydrogen) to produce gasoline, jet, and diesel should be roughly equal. Because refinery energy is mostly proportional to product versus feed hydrogen content, and the hydrogen content of gasoline, jet, and diesel products are similar. Using this same logic, LPG should be higher in CO_2 intensity and bunker-type residual fuel lower. CO_2 emission and energy consumption will be higher for heavier crudes than light, and slightly higher for naphthenic than for paraffinic crudes. Other factors should not influence refinery energy consumption as shown by the refinery model runs described in Section 3. Hydrogen content of the various feed and product streams is the main driver of refinery CO_2 intensity critically important in developing a proper allocation scheme.

4.2 Allocation approaches

Many allocation methods have concluded that refining to gasoline is much more energy intensive than distillate, which is inconsistent with the findings in the previous section, where varying gasoline/distillate ratio did not have much effect on CO_2 emissions. To understand why, a typical allocation approach was applied to the data from Section 3.

[1] Shell Internal data

[2] Join Inspection Group, Products Specifications. Aviation Fuel Quality Requirements for Jointly Operated Systems (AFQRJOS). Issue 22–28 June 2007

The energy consumptions of the individual process units from the 24 runs in Section 3 were distributed into products according to process unit yields from those runs. For example, if a given unit consumed 10 units of energy, and its yields were 40% gasoline, 40% distillate 10% LPG, and 10% resid; its 10 units of energy would be allocated 4, 4, 1, 1 to those products. For the hydrogen plant, energy was distributed to the individual units according to the relative hydrogen consumption of that unit and from there by-product, as with the normal fuel. Using this approach, gasoline was approaching a factor of two times more energy intense than distillate. But this handles hydrogen incorrectly.

In the above scheme, the fuel and feed gas associated with the hydrogen plant is allocated to the hydrogen-consuming units on the basis of their relative hydrogen consumptions, and from there to products. However, only about half of the refinery's hydrogen comes from the hydrogen plant. The remaining half comes from the catalytic reformer, which is totally associated with gasoline production. Recall from Section 4.1 that gasoline is biased toward aromatics for quality purposes (i.e., octane rating), and the reformer is the process step that gives this bias. If the refinery makes less gasoline, it would have a smaller reformer, which would make less hydrogen, which would then require a larger hydrogen plant, which would consume more energy. So the reformer, from a refinery energy and CO_2 emissions standpoint, is an energy/CO_2 equalizing device, shifting energy/CO_2 from gasoline into distillates.

If the allocation scheme does not recognize this hydrogen-equalizing feature of catalytic reforming, it will conclude that gasoline has greater CO_2 and energy intensity than jet or diesel. But once the hydrogen production of the reformer is included in the allocation, the allocation will correctly show essentially equivalent energy intensity for gasoline, jet, and diesel. Note that this decision on how to allocate is not arbitrary. Without the reformer hydrogen correction, the allocation does not match actual refinery behavior, while with it, it does. So refinery reality, not arbitrary shifting, is being used to guide the allocation method.

There are various algebraic ways of including the reformer hydrogen production in the allocation scheme. The one chosen counts the energy equivalent of hydrogen as a credit/debit to each unit (credit to H_2 producing units, debit to consuming units), and does not count the hydrogen plant (because it is implicitly counted by debiting the consuming units for the energy equivalent of their hydrogen consumption). Using this technique, the consuming units pay the CO_2 penalty for all of their hydrogen, not just the fraction of hydrogen coming from the hydrogen plant. With this technique, the CO_2 intensity of gasoline versus distillate equals out, which agrees with the observed refinery behavior, which is that refinery energy consumption does not change as gasoline to distillate ratio changes. If gasoline was more energy intensive than distillate, that would not be true.

4.3 Allocation results

The behavior described in Section 4.2 is shown quantitatively in Figs. 2 and 3. Starting with Fig. 2, which has only the coker cases, the right hand side has the results from the simple allocation without hydrogen correction. It shows much greater CO_2 intensity for gasoline using that approach. The left side of the figure includes the hydrogen correction, and gasoline is similar to distillate in CO_2 intensity. There is a slope in both blocks, with heavier crudes showing more energy consumption. This is the same slope as was seen in the left two blocks of Fig. 1 (discussed in Section 3), and is caused by the fact that heavier crudes require more coking. Fig. 3 is similar to Fig. 2, except that it has the #6 oil cases rather than the coker cases. It shows most of the same trends, for the same reasons, as Fig. 2. The only differences are that there is essentially no bias for crude heaviness, and the overall levels are lower than in Fig. 2. These differences also link back to Fig. 1, where the #6 oil cases had similar CO_2 emissions regardless of crude heaviness, and had lower CO_2 emissions than the coker cases. The slight slope with regard to crude heaviness in Fig. 3 is caused by two things: (1) the highly paraffinic far right crude is slightly low, while the highly naphthenic far left crude is slightly high, and (2) there is an eye-catching slope in Fig. 3 with regard to LPG, but LPG is a small flow, explained by other factors (see next paragraph). So concentrating on the gasoline and distillate, Fig. 3 is essentially flat with regard to crude heaviness. But while CO_2 emissions are flat, there is an indirect, heavy crude CO_2 penalty in the Fig. 3 cases because with no coker, more carbon-rich resid product leaves the refinery as the crude gets heavier.

Looking at the corrected distributions, a few other observations can be made. First, resid product has very low CO_2 intensity as no energy has been spent cracking it or adding hydrogen to it. Second, LPG has very high CO_2 intensity. While a very small amount of LPG is contained in crude oil, and is thus produced with low CO_2 intensity through simple fractionation, most of it is produced by cracking in the high CO_2 intensity cracking units. Indeed, the LPG CO_2 intensity increases with heavier crude. As crude gets heavier, the cracking units get larger, so a larger proportion of LPG comes from cracking rather than simple fractionation. And if a refinery were forced to make even more LPG on purpose by over-cracking, the LPG energy intensity would go up even further. So LPG over and above the very small quantity contained in crude oil should not be regarded as a low energy intensity product.

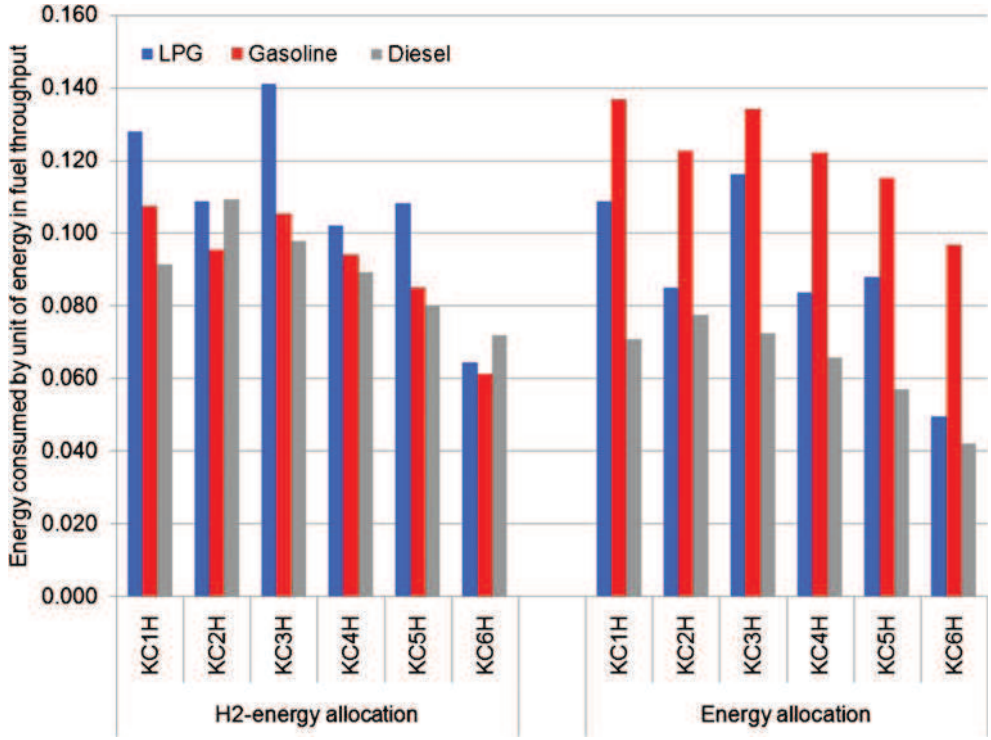

Fig. 2 Comparison between allocation methods for coker cases

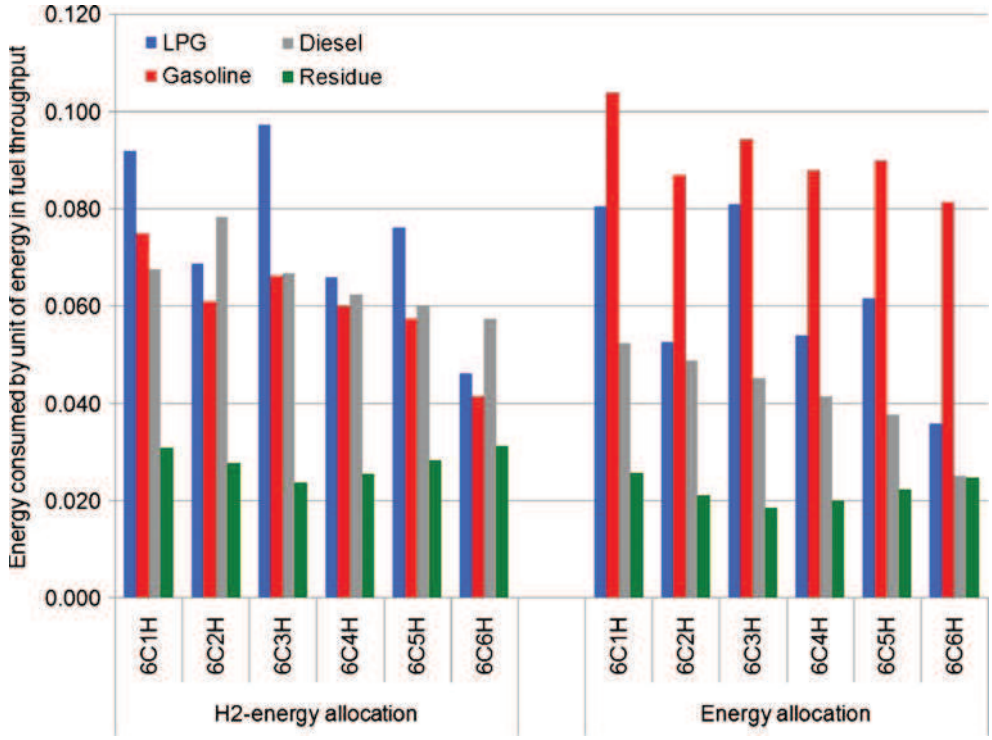

Fig. 3 Comparison between allocation methods for six oil cases

5 Conclusions

Total refinery CO_2 emissions are not strongly affected by ratio of gasoline to distillate product.

To agree with the above conclusion, an allocation scheme cannot conclude that gasoline is more CO_2 emissions intensive than distillate. To avoid that result, the allocation scheme must distribute energy into the various refinery products in a way that takes reformer hydrogen into account.

Refinery CO_2 emissions increase as it produces more transportation fuel and correspondingly less resid product. Operationally, this means that the refinery has a coker or other residue reduction unit, or said in another way, it is more complex.

In a complex refinery with a coker (or other residue reduction unit), making little or no residual fuel product, refinery CO_2 intensity is increased by running heavier crude. In a refinery that does not have a coker, and thus produces substantial quantities of residual fuel product, crude heaviness has little impact on total CO_2 emissions.

Refineries cannot vary LPG production by much, but if forced to make more LPG, total CO_2 emissions would increase. There is no way to make less LPG, it is minimized already.

While not studied explicitly in this paper, it should be self-evident that total refinery CO_2 emissions are also affected by degree of energy conservation excellence (i.e., capital equipment for energy conservation purposes) and by product specifications such as sulfur and aromatics.

6 Recommendations and perspectives

The conclusions on what impacts CO_2 intensity would seem to have obvious implications for regulatory methodologies. But there are a few added considerations that may not be immediately obvious from the conclusions themselves.

Allocation of refinery CO_2 emissions to individual products which does not stick to the technical reality is, by its very nature, rather arbitrary. This can be seen from the fact that using or not using the hydrogen corrections described in this paper has a dramatic impact on the allocation results. That arbitrariness should caution one against taking allocation results too literally. But if one insists on doing an allocation, at least it should be consistent with observed refinery behavior. The refinery behavior is that CO_2 emissions do not change very much with production ratio of gasoline to distillate. Thus, any allocation scheme which shows CO_2 intensities of gasoline and distillate are substantially different must be seen with caution, and special care should be put into understanding the handling of internal flows, the technical premises assumed, and how they align with the scope and goals of the LCA. Only with the understanding of the full context it is possible to conclude about the results and their implications.

The conclusion that CO_2 can be reduced by making more residual product in less complex refineries without cokers must be tempered with recognition that: (1) it would also lead to a carbon-rich stream (the resid) leaving the refinery; (2) refinery configurations and decision on make yield are driven many other external factors, for example, supply/demand balance of different products; and (3) well-to-wheels or life cycle effect should be considered in determining CO_2 reduction.

Similarly, the conclusion that CO_2 can be reduced by running lighter crude must be tempered with the realization that world crude demand is expected to continue to increase while world supply of light crude is limited [LBST 2007; EIA 2009]. Given that, it is likely that world demand for heavier crudes will continue to increase in the near future to meet consumer demand for transportation fuels.

Areas for further development This paper has not thoroughly handled jet versus diesel, grouping them instead as combined “distillate” fuel. If done simplistically, jet would show as being less energy intensive, because most jet comes via the crude unit and a low severity hydrotreater. But in similar fashion to LPG, if forced to make added jet, a refinery would need to include hydrocracked jet, and that is very energy intensive, often requiring a post-saturation step. Allocation methods could be developed to handle that complication, but that was thought to be beyond the scope of this paper. Instead, the simplifying step of combining jet and diesel into “distillate fuel” was adopted. However, this simplification does not undermine the conclusion that gasoline and diesel have similar overall refinery CO_2 emissions intensity. Simplistically, if jet is viewed as low CO_2 intensity, the algebra of the situation would force the intensity of diesel to be higher to balance. Thus, it does not offer a path back to the conclusion that gasoline is worse than diesel.

It is also acknowledged that precise refinery configuration or exact fuels specifications have not been studied in this study. Some runs were conducted to verify that those issues are far less important than the factors described herein, but it cannot be concluded that their effect is zero. In fact, the next phase of our work will be to study those issues more closely to determine which, if any, of such effects are non-trivial.

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Attachment KR–4

Abella and Bergerson, 2012. Model to investigate energy and greenhouse gas emissions implications of refining petroleum: Impacts of crude quality and refinery configuration. *Env. Sci. Technol.* 46: 13037–13047. DOI: 10.1021/es3018682. Includes excerpts from crude oil inventory data developed for this analysis from www.ucalgary.ca/lcaost/prelim. (Incorporated by reference in CBE supp. technical comments of 15 Sep 2014.)

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Model to Investigate Energy and Greenhouse Gas Emissions Implications of Refining Petroleum: Impacts of Crude Quality and Refinery Configuration

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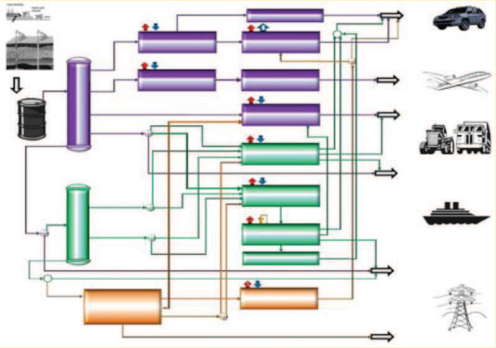
Supporting Information

ABSTRACT: A petroleum refinery model, Petroleum Refinery Life-cycle Inventory Model (PRELIM), which quantifies energy use and greenhouse gas (GHG) emissions with the detail and transparency sufficient to inform policy analysis is developed. PRELIM improves on prior models by representing a more comprehensive range of crude oil quality and refinery configuration, using publicly available information, and supported by refinery operating data and experts' input. The potential use of PRELIM is demonstrated through a scenario analysis to explore the implications of processing crudes of different qualities, with a focus on oil sands products, in different refinery configurations. The variability in GHG emissions estimates resulting from all cases considered in the model application shows differences of up to 14 g CO_2eq/MJ of crude, or up to 11 g CO_2eq/MJ of gasoline and 19 g CO_2eq/MJ of diesel (the margin of deviation in the emissions estimates is roughly 10%). This variability is comparable to the magnitude of upstream emissions and therefore has implications for both policy and mitigation of GHG emissions.



INTRODUCTION

The petroleum refining industry is the second-largest stationary emitter of greenhouse gases (GHG) in the U.S.[1] (third-largest in the world[2]). Annual GHG emissions from a large refinery are comparable to the emissions of a typical (i.e., 500 MW) coal-fired power plant.[3,4] For U.S. refineries, where most of the North American production of petroleum-derived fuels occurs, annual emissions were reported to be close to 180 million tonnes of CO_2eq in 2010, representing nearly 12% of U.S. industrial sector emissions or 3% of the total U.S. GHG emissions.[1,5−7]

This industry faces difficult investment decisions due to the shift toward "heavier" crude in the market, both domestic and imported. For example, in 1990, the fraction of imported crude into the U.S. classified as heavy (at or below API gravity, a measure of density, of 20) was roughly 4%. By 2010 this fraction had increased to 15%.[8] Between 2008 and 2015, it is estimated that more than $15 billion will be spent to add processing capacity specifically for heavy crude blends in U.S. refineries.[9] Each refinery must decide whether and how much they will process heavy crude while considering that processing such crudes requires more energy and results in higher refinery GHG emissions. These major capital investment decisions will impact the carbon footprint of the refining industry for decades to come.

Current and future environmental regulations will also affect the decisions faced by this industry. Life cycle assessment (LCA) has been expanded as a tool to enforce GHG emissions policies. For example, California's Low Carbon Fuel Standard[10] (CA-LCFS) embeds life cycle assessment within the policy to measure emissions intensity of various transportation fuel pathways through their full life cycle (including extraction, recovery, and transport). Using LCA in this way requires more accurate assessments of the emissions intensity upstream of the refinery for each crude. However, the varying quality of these crudes will also have significant implications for refinery GHG emissions. Therefore, in this paper we argue that more accurate assessments of the impact of crude qualities on refinery emissions are also required to appropriately account for the variations in emissions and avoid potential unintended consequences from such policies.

The implications for refinery GHG emissions of processing oil sands (OS) products provide a good case study due to the link between upstream processing decisions and refinery emissions, as well as the wide variety of OS products. Canada has the world's third largest petroleum reserves and is the top supplier of imported oil to the U.S.[11] The OS resource represents over 97% of Canada's oil reserves.[12] Current OS operations produce bitumen (an ultraheavy petroleum product) that undergoes either dilution (to produce diluted bitumen referred to as dilbit, synbit, or syndilbit) or upgrading processes

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Table 1. Canadian Crudes under Analysis[a]

	Crude Categories	*Production Volumes*	*Configuration selected in Base Case*	*Description*	*S wt%*	*API*	*H wt%*	*MCR wt%*	*~Kw*	*Tb_{50} (°C)*
Bitumen 1	**Bitumen** No bitumen currently goes to refinery. Bitumen case may apply if diluent (condensate) is not used at the refinery.	1.4 M bpd in 2009 including bitumen processed at upgraders[b]	Deep Conversion: Coking and fluid catalytic cracking	Confidential	5.0	8.2	10.1	14.7	11.6	427
Bitumen 2				Confidential	4.1	12.1	10.3	10.9	11.0	442
Dilbit 2	**Diluted bitumen**: (Dilbits) using condensate at a 25:75 % diluents-to-bitumen ratio. Synthetic bitumen blend (Synbit) 50:50 % Light SCO -to-crude ratio. Syndilbit is a bitumen blend with Light SCO and condensate.	Synbit and Syndilbit comprise nearly 2% OS production[b]	Deep Conversion: Coking and fluid catalytic cracking	**Cold Lake (CL):** Asphaltic heavy crude blend of bitumen (11API/5.5%S) and condensate (65API/0.1%S). CL Production ranges from 150 kbd to 200kbd of blend	3.9	20.7	11.2	10.6	11.8	458
Syn-dilbit 1		All diluted bitumens comprise nearly 49% OS production[b]		**Albian Heavy Synthetic** (AHS) contains vacuum residuum (which is an exception for SCOs). It is a blend of sweet SCO crude with unconverted oil from resid hydrocracking	2.2	19.5	10.7	10.9	11.6	447
SCO, So,H1	**Synthetic Crude Oil (SCO)** is a blend of naphtha, distillate, and gas oil range crude fractions. Sweet (Sw) blends comprise majority of SCO production. It has been estimated that 75% of the 2007 SCO production was light Sw SCO without vacuum resid [56]	Nearly 13% OS production[b]	Deep Conversion: Coking and fluid catalytic cracking	**Suncor Synthetic H (OSH)** is a sour synthetic blend. It is comprised of roughly 75% virgin gas oil and 25% lighter fractions.	3.1	19.9	11.1	0.6	11.4	393
SCO, Sw, M1		Nearly 38% OS production[b]	Medium Conversion: fluid catalytic cracking	**Syncrude Synthetic** (SYN) sweet SCO derived from combination of hydroprocessing and fluid coking technologies at upstream upgrading operations. SYN production 58.9 kbd	0.1	31.5	12.5	0.1	11.8	321
SCO, Sw, L1			Hydroskimming	**Husky Synthetic Blend** (HSB) sweet SCO derived from combination of hydroprocessing and delayed coking technologies at upstream upgrading operations. Upgrading production is around 53 kbd	0.1	32.6	12.9	0.1	11.9	329
SCO, Sw, L2				**Suncor Synthetic A (OSA)** sweet SCO. Suncor Upgrading production is around 280 kbd; 60% production is light Sw SCO. i.e., OSA production close to 168kbd	0.2	33.1	12.7	0.02	11.9	315
Conv, So,H1	**Canadian Conventional crude (Conv)**, as oil sands products, are classified based on API (Light API>32, Medium 32>API>22, Heavy API <22) and sulfur content (Sweet S< 0.5wt%, Sour S> 0.5wt%)	6% U.S. Crude oil imports[c]	Deep Conversion: Coking and fluid catalytic cracking	**Bow River North.** Conventional benchmark.	2.7	21.1	11.64	8.57	11.7	427
Conv, So, M1			Medium Conversion: Fluid catalytic cracking	**Midale** (Benchmark medium sour crude)	2.3	29.6	12.1	5.8	11.9	361
Conv, So, L2				**Sour High Edmonton**	1.4	34.9	12.8	3.8	12.8	323
Conv, Sw, L2			Hydroskimming	**Mixed Sweet Blend**	0.4	39.2	13.2	2.0	12.2	298

[a]S: Sulfur content; API: gravity; H: hydrogen content; MCR: micro carbon residuum; ~Kw: approximated Watson characterization factor using Tb_{50} in wt.; Tb_{50}: temperature at which 50% of the mass is recovered through distillation of the whole crude; wt: weight basis; So: sour; Sw: sweet; H: heavy; L: light; kbpd: thousand barrels per day. [b]Calculation basis (2009): 1361 kbpd of oil sands products derived from 1269 kbd of raw bitumen,[57] and 75% of the SCO production ends in sweet light products. [c]Calculation basis (2009): 1269 kbpd U.S crude oil imports from Canada (i.e., 21% of U.S. crude oil imports).[8] 898 kbpd oil sands products exported to U.S. (i.e., 67% of oil sands products[57]); thus, 371 kbpd conventional crude oils exported to U.S. (i.e., 4% of U.S. crude oil imports).

(to produce a high quality synthetic crude oil, SCO) prior to sale to petroleum refineries. Therefore, a diversity of product quality is possible from these operations. Table 1 lists and describes the main characteristics of each category of OS products. The impacts of different OS processing decisions on refinery GHG emissions have the potential to be large and have yet to be explored in depth.

A petroleum refinery is a set of interconnected but distinct process units that convert relatively low value liquid hydrocarbon material (resulting from blending multiple streams of crude feedstock) into more valuable products by increasing its hydrogen to carbon ratio. Different combinations of process units (configurations) are possible leading to a wide variety of potential refinery configurations. In a refinery, a distillation process separates the "whole crude" into groups or "fractions". These fractions are made up of molecules with a particular boiling point temperature range. These ranges are defined by "cut temperatures". Each fraction is then sent to different process units where chemical and thermal processes fragment and/or rearrange the carbon and hydrogen bonds of the hydrocarbon while eliminating the undesired components such as sulfur and nitrogen that are also present in each fraction. Each refinery has a final product specification which dictates the volume and quality of each desired end product (e.g., *X* barrels

of gasoline with Y% sulfur). A combination of input crudes is selected and process units are operated to satisfy such specifications.

Crude quality and refinery configuration affect GHG emissions related to processing a particular crude. Crude quality is defined by physical and chemical properties (e.g., the hydrogen content of the crude fractions) that determine the amount and type of processing needed to transform the crude into final products. The technologies employed, as well as how they are combined in operation in a refinery, will require different types and amounts of energy inputs and will produce different types and amounts of energy byproducts (e.g., coke) and final products (e.g., gasoline). For example, heavier crudes generally require more energy to process into final products than lighter crudes due to their need for additional conversion processes and their low hydrogen content.

Two prominent North American life cycle (LC) tools are now forming the basis of regulation as opposed to their original objective of informing policy: Natural Resource Canada's GHGenius[13] and Argonne National Laboratory's Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET).[14] The GREET model and the CA-GREET version, used as the basis of CA-LCFS, do not account for the effects of crude quality at the refinery stage in their calculations (i.e., all crudes will have the same energy requirements and GHG emissions). GHGenius accounts for crude quality by modifying a default energy intensity value using the average API gravity and sulfur content of an entire refinery crude slate (i.e., a combination of crudes blended as they enter the refinery) and a regression model based on historic regional refinery performance data. [15] The LC models' approaches do not decouple the effects of changes in energy requirements due to changes in crude quality and the changes in each refinery's performance (e.g., process unit efficiencies), nor do they develop a consensus on the impact of allocation (how environmental impacts are split across products in a multiproduct industry).[16] It is possible to combine the use of LC-based models and refinery simulators to calculate LC energy use and GHG emissions for a particular crude and refinery;[17] however, this is not a straightforward effort as will be demonstrated by this paper.

Peer-reviewed analysis that investigates energy and GHG implications of shifting to heavier crudes in refineries has only recently started to appear (since 2010).[18,19] However, these studies did not explore differences in emissions intensity of selected technologies nor investigate the full range of different qualities of crudes derived from the OS operations. Three nonpeer reviewed studies, conducted using a LC framework, have investigated OS crude quality effects on refinery GHG emissions.[17,20−22] However, these studies have used proprietary refinery models limited in the transparency needed to understand the boundaries, assumptions, and data used as well as the ability to evaluate alternate scenarios or pathways.[23] The literature does not present a transparent tool nor recommend a method that predicts GHG emissions with the ability to capture the impact of crude quality and refinery configuration (see Supporting Information (SI) for detailed review of the literature).

This paper (1) provides an overview of the development of the Petroleum Refinery Life-cycle Inventory Model, PRELIM, including model structure and crude assay inventory as well as calculations and assumptions; (2) applies the model to assess the impact of crude quality and refinery configuration on energy use and GHG emissions including a comprehensive set of OS products and conventional crudes; (3) explores the most influential parameters in the model for determining energy use and GHG emissions through scenario analysis; and (4) compares results from previous studies with those from the application of PRELIM.

■ METHOD

PRELIM is a stand-alone, spreadsheet-based model built using a LC approach by employing refinery linear programming modeling methods to represent a range of possible configurations reflecting currently operating refineries in North America. The LC/systems-level approach provides the structure to obtain a tool of wide applicability (i.e., not specific to any one refinery but capable of representing a wide variety of refinery configurations) in the assessment of refinery LC energy use and GHG emissions for crudes of different quality, and allows for the easy incorporation of model results into Well-To-Wheel analyses (WTW). WTWs are a variant of LCAs focused on transportation fuels. The refinery linear programming modeling methods[24] allow for process unit and overall refinery mass balances. These methods overcome the lack of crude specificity of previous LC models[16,25,26] and facilitate exploration of alternative LC inventory allocation methods at the refinery subprocess (i.e., process unit) level. Because the model structure allows for the investigation of two key LCA concepts (i.e., functional unit and allocation[27−29]) as recommended by the International Standard ISO 14041,[30] the model has been called the Petroleum Refinery Life-cycle Inventory Model.

Model Structure and Key Assumptions. Scheme S.1 in the SI presents a basic flow diagram of the overall refinery model structure and how the process units are connected. PRELIM can simulate up to ten specific refinery process configurations. All refinery configurations include crude distillation, hydrotreating, and naphtha catalytic reforming processes. The configurations are differentiated by whether or not the following conversion technologies are present: gas oil hydrocracking, fluid catalytic cracking (referred to hereafter as FCC), delayed coking, and residual hydrocracking. Supporting unit processes such as steam methane reforming (SMR) and acid gas treatment are also included.

Each configuration requires a different amount of energy to process a crude and produces a different slate (i.e., volume and type) of refinery final products including transportation fuels (i.e., gasoline, kerosene, and diesel) as well as heavy fuel oil, hydrogen from the naphtha catalytic reforming process, refinery fuel gas (i.e., gas produced as a byproduct in process units within the refinery), and the possible production of coke or hydrocracking residue. To run the model, a user must select the crude, the configuration, and the allocation method desired through the spreadsheet-based interface. Default values can be used to represent the crude properties and energy requirements of each process unit. Crude properties can be represented by selecting a crude from the crude assay inventory in the model. Alternatively, a user can input a new crude assay and/or can modify any of the process unit model parameters either by selecting a value from the range of parameter values available in the model or by inputting their own parameter value(s). To characterize the whole crude and its fractions, a total of 62 parameters are input to the model, accounting for five crude oil properties: crude distillation curve (i.e., information about mass and volume yields of each fraction, and individual fraction characteristic boiling point), API gravity, sulfur content,

hydrogen content, and carbon residue. Supporting information describes how these crude properties affect the refinery energy use and GHG emissions estimates. Two additional crude properties, aromatic content and crude light ends content, impact refinery GHG emissions estimates and are modeled indirectly in PRELIM. PRELIM uses information about the quantity and type of energy required by an individual refinery process unit and assumes that the process energy requirements (electricity, heat, and steam) are linearly related to the process unit's volumetric feed flow rate.[31] This assumption is key to differentiate the energy required to refine crudes with different distillation curves (and therefore different volumes of each fraction that will pass through each process unit). Justification is provided in the SI.

PRELIM calculations include the upstream energy use and GHG emissions associated with the energy sources (i.e., electricity and natural gas).[32] Fugitive GHG emissions from a refinery tend to be an order of magnitude lower than combustion emissions[33] and are not considered in the current version of PRELIM.

The data available in the model for process unit energy requirements are presented as a default as well as a range of plausible values for each parameter derived from the literature.[24,34−37] The data were compared with confidential information and evaluated in consultation with experts from industry to verify that the values and their ranges are appropriate. PRELIM default values for process unit energy requirements are mostly from Gary et al.[35,38]

PRELIM can calculate overall refinery energy use and GHG emissions on a per barrel of crude or per megajoule (MJ) of crude basis, as well as energy use and GHG emissions attributed to a particular final product on a per MJ of product basis (e.g., per MJ of gasoline). For the latter type of functional unit, refinery energy use is allocated to final products at the refinery process unit level (SI details PRELIM allocation procedures, available options in the model, and the implications of different allocation methods). Summing the energy use across all refinery final products on a mass flow rate basis, and comparing to the total energy requirements summed across all process units, verifies the energy balance in the system (all results are reported on a lower heating value basis).

Differences in hydrogen content among crude feedstock and refinery final products are important factors that drive refinery CO_2 emissions.[19] In PRELIM, a global hydrogen mass balance method[39] is used to determine hydrogen requirements for each hydroprocessing unit (hydrotreating and hydrocracking) as well as byproduct hydrogen production from the naphtha catalytic reforming process unit. The method accounts for differences in the hydrogen content of different crudes and the assumption that all crudes are to be processed to meet intermediate and final product hydrogen specifications. Accurately estimating hydrogen requirements is one of the most critical model components (see SI for a more detailed discussion).

PRELIM uses correlations to determine yields of intermediate and final refinery products for each process unit. All correlations used in PRELIM are based on Gary et al.[35] The SI details assumptions about product yields for each process unit.

PRELIM Crude Assay Inventory. The PRELIM crude assay inventory is developed to allow a user the option to select from a predetermined list of crude assays. The current inventory includes publicly available data representing 22 Western Canadian crudes tracked by the Canadian Crude Quality Monitoring Program (CCQMP).[40] Also, the inventory includes seven additional assays from confidential sources to characterize a comprehensive range of qualities for OS-derived products (i.e., bitumen, diluted bitumen, SCO). Currently, there are at least two crude assays representing each category of crude (e.g., bitumen, diluted bitumen, and SCO are all categories of crudes). Western Canadian Conventional crudes are well-characterized using the data available in the public realm. Due to data availability we do not include a full suite of conventional crudes in our analysis. However, preliminary analysis of international crudes shows that the range of emissions presented for Canadian conventional crudes provides a rough approximation of the range of refinery emissions for light crudes globally. However, further analysis is required to confirm this and provide a complete LC comparison.

PRELIM requires characterization of the properties for nine crude fractions (see Scheme S.1). The method of separating the crude into nine fractions is selected to allow the flexibility needed to model different refinery configurations. CCQMP assays must be transformed to obtain the complete set of information needed. The SI details the transformation methods and the results of an evaluation of the methods used. In PRELIM, each particular crude assay is run individually, as opposed to running a crude slate. A crude-by-crude analysis was also suggested and tested in ref 22, and the impact of this simplification on emissions estimates is expected to be small.

Model Evaluation. PRELIM reduces the level of complexity in modeling refinery operations compared to the models used by the industry to optimize their operations. Confidential data (associated with crude assays, operating conditions, and energy requirement estimates) and consultation with refining experts were necessary to assess the validity of PRELIM input data and assumptions. In addition, sensitivity analyses and/or alternative logic calculations to estimate particular parameters were conducted. Finally, a covalidation exercise was conducted by comparing PRELIM's outputs with those of a more detailed refinery model to assess PRELIM's performance, identify any improvements required, and specify the level of accuracy that can be expected when using the model to inform policy.

The covalidation shows that the PRELIM model is capable of replicating the estimates of CO_2 emissions from a more complex model with a reasonable range of error/variability. Overall, the margin of deviation in the emissions estimates due to both assay data quality and the modeling approach is below 10% in almost all cases, which is within the error bounds of typical LC inventories.[41−43] Deviations in energy requirements, which lead to emissions deviations, are mainly associated with estimates for the hydrogen required which is also an uncertain variable in actual refinery operations.[39,44] The deviations are also explained in part by flexibility exhibited by real refinery operating conditions as well as assumptions in modeling. The SI details methods and results of this exercise.

Model Application. A scenario analysis[45] is used to explore the effects that crude quality and refinery configuration have on refinery energy use and GHG emissions estimates.

The starting point for the analysis is a "Base Case Scenario" (referred to hereafter as base case): a set of conditions (e.g., different crudes, emission factors, process unit energy intensities, allocation assumptions) to determine the refinery energy use and GHG emissions of a crude in a "default" refinery configuration. The purpose of the base case is to explore plausible scenarios in which only energy use and GHG emissions associated with the minimum processing capacity needed to transform each crude into transportation fuels or

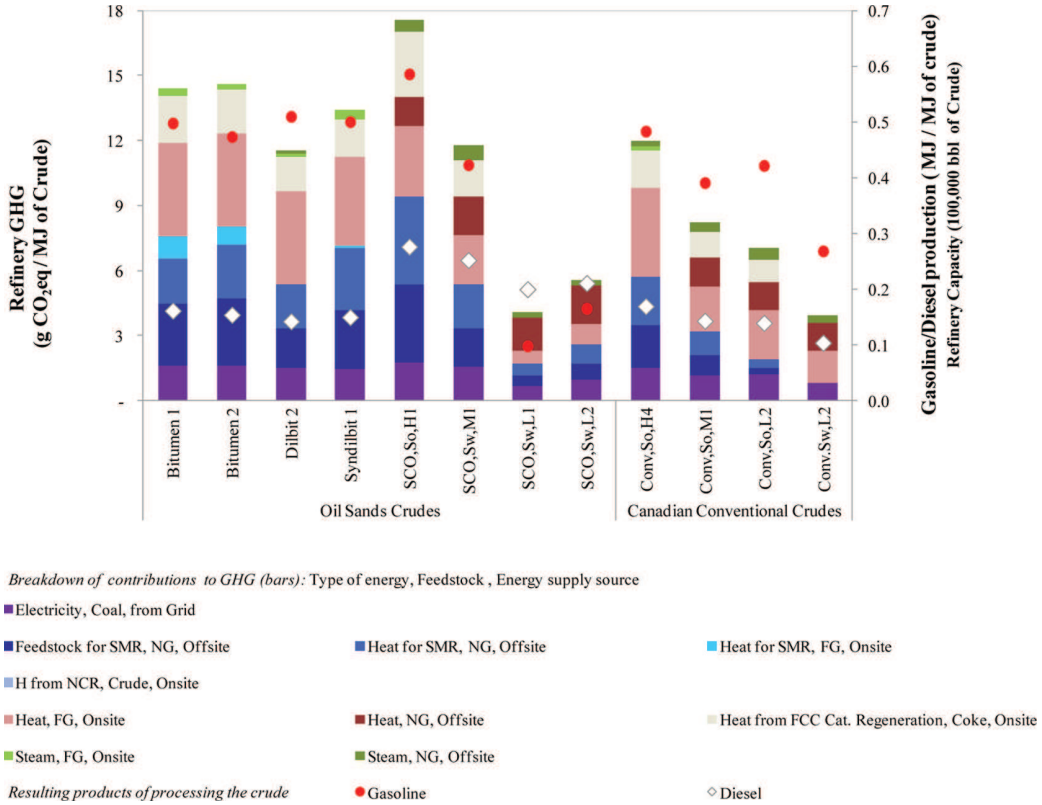

Figure 1. Base case greenhouse gas (GHG) emissions estimates and gasoline and diesel production from refining 100 000 bbl of different crudes. Major assumptions about base case: (1) Refining configuration is based on API and sulfur properties of the whole crude for both crude categories Conventional and OS-derived crudes: API (light API > 32, medium 32 > API > 22, heavy API <22) and sulfur content (S) (sweet S < 0.5 wt %, sour S > 0.5 wt %). Sweet light crudes (Sw, L) are run in a hydroskimming refinery; sour light (So, L), sweet medium (Sw, M), and sour medium (So, M) crudes are run in a medium conversion refinery; and heavy crudes (H: conventional, bitumen, dilbits) are run in a full conversion refinery. (2) Upgrading process units for the medium conversion refinery include a fluid catalytic cracking (FCC) process unit, and upgrading process units for full/deep conversion refinery include FCC and delayed coking process units. (3) A float case is assumed where crude properties and the refinery configuration (i.e., level of refining) determine the amount of gasoline and diesel produced. (4) Energy sources: hydrogen (H) via steam methane reforming (SMR) of natural gas (NG); refinery fuel gas (FG) from the crude and refining process units (RP) offsets NG consumption. FG is allocated through prioritizing the different NG requirements in the refinery (i.e., heat for processing, heat for steam, heat for SMR, and SMR feedstock) based on its heating value until it is exhausted. Heating values: 46.50 MJ/kg RFG low heating value (LHV) on mass basis and 47.14 MJ/kg NG LHV on mass basis.[58] Byproducts such as H via naphtha catalytic reforming (NCR) and coke deposited on FCC catalyst offset energy requirements as well. FCC regeneration must burn off the coke deposited on FCC catalyst to restore catalyst activity, which releases heat that satisfies most of the heat requirements of the FCC. FCC regeneration coke burned to complete combustion (coke yield 5.5 wt % FCC feed[35] and coke carbon content 85 wt %).[59] (5) Combustion GHG emissions factor is assumed the same for NG and FG combustion (56.6 g CO_2eq/MJ). H via NCR does not have any share of emissions due to allocation method employed. Electricity 100% coal-fired power (329 g CO_2 eq/MJ).[58] SI shows GHG emissions attributed to gasoline and diesel on a per MJ of product basis (Figure S5).

other final products is taken into account. In PRELIM, the default refinery configuration is set based on a set of three broad refinery categories: hydroskimming refinery, medium conversion refinery, and deep conversion refinery[46] as suggested by Marano.[47] All 10 refinery configurations in PRELIM fit into one of these three categories. The base case assigns each crude (OS and conventional) to the appropriate default refinery category, using API gravity and sulfur content of the whole crude as the criteria. Default process energy requirements are represented by literature values. A float case is assumed where crude properties and the refinery configuration determine the final product slate. When the alternative functional units are explored, refinery emissions are allocated to transportation fuels (i.e., gasoline, diesel, and jet fuel) on a hydrogen content basis (based on discussion in 19) across the scenarios. The SI details additional assumptions.

Four possible alternative refinery operating scenarios are created from a screening of parameters through sensitivity analysis and a collection of a range of plausible values for each parameter. These scenarios explore the impact of different refinery configurations available in PRELIM (crudes will not always end up in the default refinery configuration); variations in process energy requirements (greater efficiencies are possible than currently represented by the default values used); and, variations in fuel gas production calculations (a parameter that greatly varies throughout the industry).

Results are presented for a total of 12 assays out of the 29 present in PRELIM's assay inventory, selected to represent a range of qualities of crude for each category of crude (Table 1). For example, diluted bitumen is represented by "dilbit 2" and "syndilbit 1". These two assays are selected as they represent the highest and lowest overall refinery GHG emissions estimates respectively from the eight assays of diluted bitumen

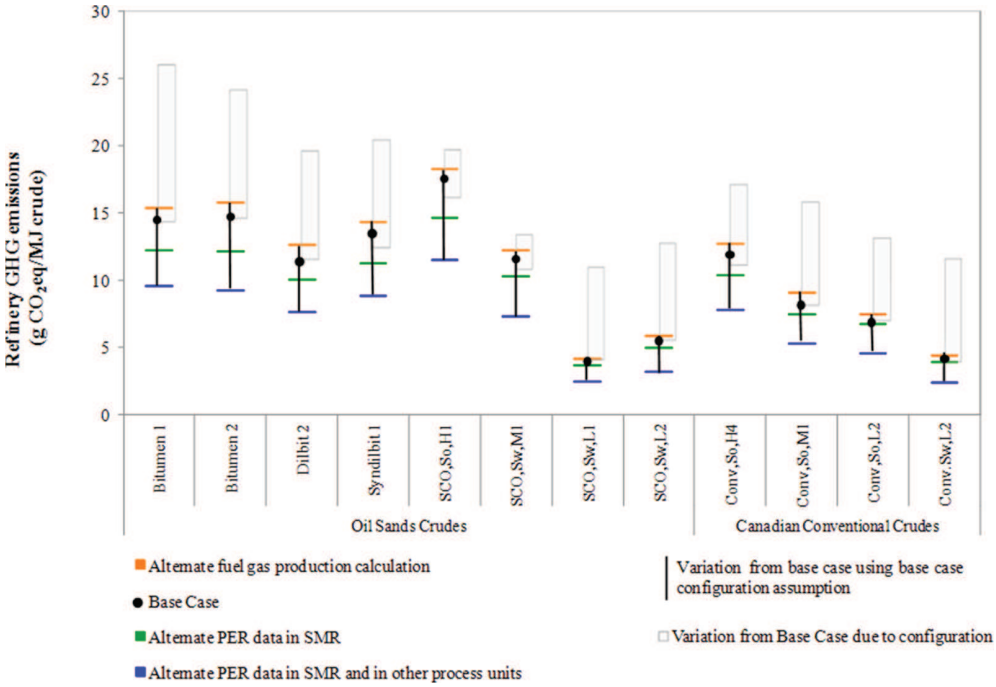

Figure 2. Scenario analysis overall refinery greenhouse gas (GHG) emissions. Scenarios: The base case represents the assumptions presented in Figure 1. Alternate process energy requirements (PER) data in steam methane reforming (SMR) uses a 91% energy efficiency as MJ hydrogen produced/MJ net energy use; energy use accounts for steam production inside SMR that is exported to other process units.[26] Alternate PER in SMR and in other process units simulate additional improvements on energy requirements in other refinery process units based on process energy use confidential data (overall efficiency improvement of approximately 30%). Alternate fuel gas production calculation assesses increasing refinery fuel gas production using an alternative calculation method to determine fuel gas production in hydrotreating process units. PRELIM uses a simple method to determine the amount of refinery fuel gas. The alternative calculation is based on hydrogen requirement specific to each crude while holding other base case assumptions constant that ends in high estimates in the amount of refinery fuel gas (average increase of 2.5% across all process units); variations in emissions are mainly associated with the hydrogen content of the total amount of refinery fuel gas. Variation from Base Case due to configuration defines range of GHG estimates associated with use of different refinery configurations while holding other base case assumptions constant. The SI shows scenario analysis estimates of GHG emissions attributed to gasoline and diesel on a per MJ of product basis (Figure S5).

in the assay inventory. Publicly available assay data are used for all OS assays with the exception of raw bitumen which is currently not processed directly in a refinery so data are not publicly available. The publicly available assays are streams or blends of crudes of different qualities flowing through pipelines in Canada. These streams were used to represent specific crude categories (e.g., diluted bitumen, SCO) through consultation with industry and academic experts to ensure that they represent an accurate range of characteristics for each category of OS-derived crudes. Conventional crudes are presented for the purposes of comparison. Table 1 provides a summary of all 12 assays, current production volumes of each crude category, source of data, and properties of the whole crude.

RESULTS

Base Case Results. Under the base case assumptions, total refinery energy use ranges from 0.06 to 0.24 MJ/MJ of crude (340−1400 MJ/bbl of crude). A detailed discussion of energy use is presented in SI. As expected, energy use has a positive linear relationship with the GHG emissions. The resulting GHG emissions of processing crudes of different qualities can vary widely, mainly due to differences in hydrogen requirements. Total refinery GHG emissions range from 4 to 18 g CO_2eq/MJ of crude being processed (23−110 kg CO_2eq/bbl of crude). For the 12 crudes considered in the base case, the supply of hydrogen contributes from 0 to 44% of refinery emissions, process heating contributes 26−71%, FCC catalyst regeneration contributes 0−17%, steam contributes 2−7%, and electricity contributes 10−21%. Up to 48% of the emissions associated with hydrogen requirements result from the chemical transformation of natural gas into hydrogen in the SMR process unit. Zero emissions from hydrogen supply are possible where hydrogen requirements are low enough to be met by coproduction of hydrogen via naphtha catalytic reforming. This form of hydrogen is considered to be a byproduct and therefore a CO_2eq emissions-free stream as the base case assumes that emissions are allocated only to final refinery products. Generally, the GHG emissions estimates from each energy type are proportional to their contribution to overall energy use with the exception of electricity, for which emissions are determined by the emissions intensity of electricity production (further discussion in SI).

Figure 1 shows that the amount of gasoline and diesel produced from the same amount of input (i.e., 100 000 barrels of crude) also varies with crude quality, but to different extents (further details in SI).

Alternative Scenario Results. Figure 2 presents the base case GHG emissions (also presented in Figure 1) for each crude as well as variation from the base case due to changes in assumptions regarding refinery configuration, process energy requirements, energy use for production of hydrogen via SMR, and refinery fuel gas production.

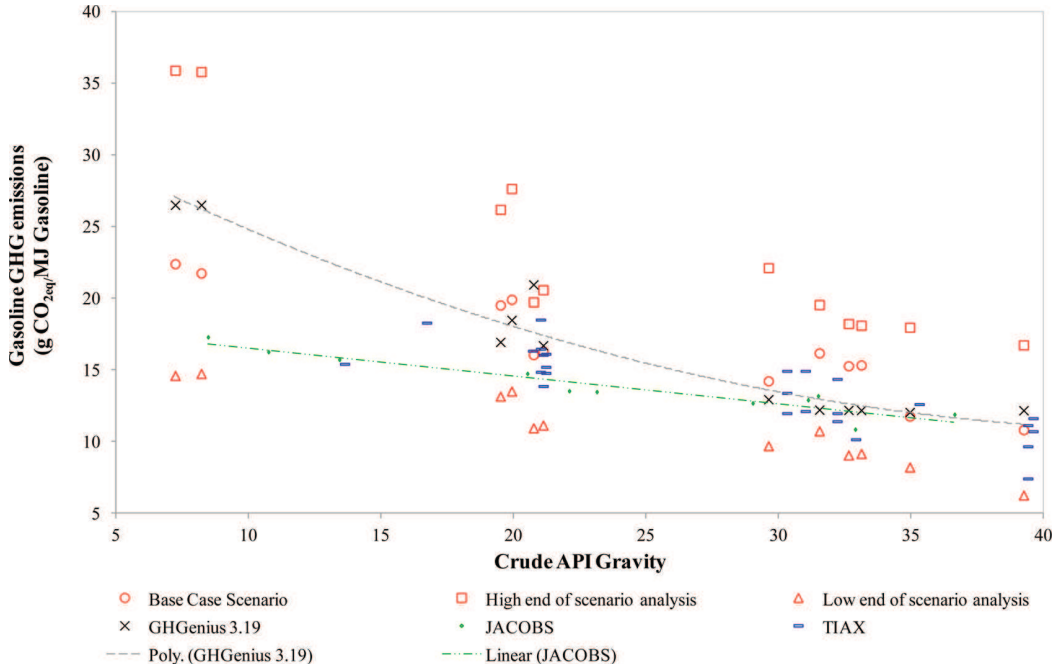

Figure 3. Comparison of GHGenius, JACOBS, TIAX, and PRELIM gasoline greenhouse gas (GHG) estimates. Base case estimates and variation from the scenario analysis presented in Figure 1. Variation from base case can be compared with variation in TIAX estimates;[17] TIAX study accounted for alternative configurations and/or energy efficiencies (i.e., different U.S. production regions). If PRELIM uses the same configuration as JACOBS[22] while holding other assumptions to base case constants, PRELIM replicates similar linear regression as JACOBS results suggest. GHGenius[60] estimates are from default GHGenius v.3.19 assumptions while varying API gravity and sulfur of crude using PRELIM assay inventory (polynomial regression built in GHGenius from crude slates of API > 25.4 and using Canadian industry forecast data). The GREET model emissions estimates are not included in the figure as there is no variation presented due to crude quality (the default gasoline carbon intensity is estimated at 10.5 g CO2eq/MJ of gasoline). Gerdes model estimates[25] and recent GHGenius estimates[61] using a linear relationship approach (which are not included in the figure) are also in the range of gasoline GHG emissions estimates resulting from the low end of the scenario analysis and TIAX as illustrated by Brandt.[49] These estimates are not included in the figure as they are either duplications of the same data or present very similar trends and ranges.

The magnitude of the impact on results from varying the refinery configuration is crude-specific but in general this factor has a greater impact than any other individual factor considered. When the full range of refinery configurations are run for each crude, the emissions can change as much as 12 g CO_2eq/MJ of crude (71 kg/bbl of Bitumen1) or up to 190% (Conv,Sw,L2: conventional sweet light crude 2 as indicated in Figure 2). Lighter and sweeter (lower in sulfur) crudes have increased GHG emissions above the base case since the base case assumes a simple hydroskimming configuration, and for heavier crudes (OS and conventional) there are deep conversion configurations in which the GHG emissions are higher or lower than those estimated in the base case. Therefore, the method used in the base case for assigning crudes to a default or "ideal" level of conversion is incomplete if the goal is to predict the full range of potential GHG emissions associated with refining a particular crude (as a crude could be processed in a variety of refineries with different configurations). Therefore, the specific refinery configuration and the associated process units play an important role.

Process unit energy requirements, as well as refinery fuel gas production, can vary significantly and collectively; this variation can result in a wide range of emissions estimates, implying that attention has to be placed on these assumptions and their implications for policy. Improving energy use in hydrotreating, FCC, naphtha catalytic reforming, delayed coking, and SMR process units (represented by real refinery operating data with higher levels of efficiency than the literature data used in the base case—overall efficiency improvement of approximately 30%) decrease GHG emissions by 34% (5 g CO_2eq/MJ of Bitumen1) to 43% (2 g CO_2eq/MJ of SCO,Sw,L2). Increasing the estimated production of refinery fuel gas (average increase of 2.5% across all process units) can increase GHG emissions by as little as 1% (0.02 g CO_2eq/MJ of SCO,Sw,L1) or as much as 10% (0.8 g CO_2eq/MJ of Conv,So,M1; up to 1 g CO_2eq/MJ of Bitumen 1). The SI details results of other scenarios.

As a whole, Figure 2 illustrates that a wider range of GHG emissions estimates is seen for OS products (2.5−26 g CO_2eq/MJ of crude) compared to conventional crudes (2.4−17 kg CO_2eq/MJ of crude). Generally, the highest estimates are for bitumen (9.3−26 kg CO_2eq/MJ of crude). This represents potential cases such as dilbit being sent to a refinery and the diluent being separated and returned to the OS operation. GHG emissions from refining diluted bitumen range between 7.6 and 20 g CO_2eq/MJ of crude. The SCOs represent one of the highest and the lowest GHG emissions of all crudes considered. The heavy SCO crude category can have GHG emissions as high as 20 g CO_2eq/MJ of crude. Light sweet SCO can have GHG emissions as low as 2.5 g CO_2eq/MJ of crude. Light/heavy crude differentials may provide an incentive for the production of light SCO; however, this differential can decrease in a market with increasing supply of heavy oil and refineries increasing their capabilities to manage that feedstock. The SI discusses PRELIM's SCO refinery GHG emissions estimates in detail. It is important to note that the high and low ends of the GHG emissions for OS crudes represent the cases of recycling

of diluent (bitumen as a feedstock) and upgrading the bitumen prior to entering the refinery (high quality SCO) which have upstream processing requirements quite different from conventional crudes and will have different implications on a full LC basis.[48]

Alternative Functional Units. Given recent regulations such as the CA-LCFS, there has been increased interest in representing LC emissions on a per product basis. This requires allocation of total refinery emissions to each product. Assuming GHG emissions are allocated only to transportation fuels (i.e., gasoline, diesel, and jet fuel) on a hydrogen content basis (based on discussion in 19) across the scenarios, conventional crudes' gasoline GHG emissions estimates range from 6.2 to 22 g CO_2eq/MJ of gasoline, and OS products' GHG emissions estimates range from 9.0 to 36 g CO_2eq/MJ of gasoline. Diesel GHG emissions estimates for conventional crudes and OS products range from 2.3 to 26 g CO_2eq/of MJ of diesel and 3.3 to 36 g CO_2eq/MJ of diesel, respectively. Figure S5 illustrates gasoline and diesel GHG emissions estimates for the scenario analysis. The implications of different allocation methods are explored in the SI.

Overall refinery GHG emissions (i.e., per bbl or MJ of crude) will be greatly influenced by the refinery configuration employed. However, for some crudes, when the emissions are calculated on a per product basis (e.g., per MJ gasoline) the impact of the configuration can play a lesser role as the significant differences in emissions between configurations are tempered by the differences in the amount of product produced (Figure S5). For example, if light sweet SCO is processed in a deep conversion refinery instead of a hydroskimming refinery, it will undergo more intense processing and therefore result in both higher overall emissions as well as a higher volume of gasoline produced. This difference has implications in terms of potentially providing an incentive for one action (e.g., sell SCO to hydroskimming refinery) if the crude is being evaluated on an overall crude basis (i.e., all products) and a second action if it is evaluated on an individual product basis (e.g., sell SCO to deep conversion refinery).

Comparison with Other Studies. In the absence of a public-domain refinery modeling tool, the use of regression models based on sulfur content and API gravity of the whole crude is being generalized for the purposes of modeling crude quality effects on refinery GHG emissions.[49] Some studies assume a linear relationship[18,22,25] while others assume a quadratic relationship[15] for the regression model, and consensus has not yet been reached. The results reported by previous refinery models/studies are within the ranges calculated by the PRELIM model (Figures S6−S7). Figure 3 demonstrates that the degree of correlation between the gasoline GHG emissions estimates from refining and the whole crude API gravity is affected by assumptions about configuration and process energy requirements. This is also true for diesel (Figure S8). In addition, sulfur does not make a large contribution to predicting GHG emissions. PRELIM can replicate the results of previous studies when similar assumptions are made. However, the figure shows that previous studies do not provide the full range of emissions possible.

■ DISCUSSION

PRELIM goes beyond public LC-based modeling approaches by adding the detail required to evaluate the impact of crude quality and refinery configuration on energy use and GHG emissions of refining while remaining a transparent spreadsheet-based tool. The model is based on public data but is validated by confidential operating data and expert review. This approach allows for improved confidence in the model results while providing the detail required for users to replicate the results and make use of the framework. It provides more detailed calculations (e.g., includes a hydrogen balance at a process unit level) than current LC models but with less detail (thereby increasing manageability/transparency) than proprietary refinery energy optimization models. PRELIM is capable of replicating the findings from more complex models with an overall margin deviation below 10% in almost all cases, which is within the bounds of typical LC inventories.[41−43] PRELIM provides a data framework that can be integrated as a module in Well-To-Wheel models and used by academia, industry, and government to develop a consistent reporting structure for data in support of GHG emissions modeling for policy purposes.

Further model development should include the establishment of a statistical relationship between hydrogen content, aromatic hydrocarbon content, and the emissions intensity of processing a specific crude. The current assumption of processing all crudes to the same intermediate product specification may overestimate energy requirements for high quality crudes in medium and deep conversion refineries. Also, it is recommended that opportunities to improve the accuracy of hydrogen requirement estimates be explored. The inclusion of modeling crude input slates instead of individual crudes, economic data, and other environmental impacts, as well as tools for decision-making analysis such as Monte Carlo simulation, will enhance model capabilities.

The PRELIM application presented in this paper demonstrates that crude quality and the selected process units employed (i.e., the refinery configuration), as well as the energy efficiency of the process units, all play important roles in determining the energy requirements and emissions of processing a crude. The unique amount of hydrogen required to process each crude is dictated by the quality of the crude entering the refinery. It can be the major contributor to refinery energy use and GHG emissions for every crude. Therefore, this should be a key parameter used in estimating emissions. Emissions associated with providing the hydrogen required should also be the focus of emissions reductions at refineries.

This analysis provides insights that can help to inform emissions reductions decisions at refineries. Based on this analysis, the top three ways to reduce GHG emissions at refineries processing heavier crude will be to (1) reduce the amount of hydrogen consumed, (2) increase hydrogen production efficiency (and/or lower GHG emissions intensity of hydrogen production), and (3) capture CO_2 from the most concentrated, highest volume sources (i.e., FCC and SMR). All of these alternatives involve several technologies that require further study and can be included as new modules in future versions of PRELIM. Moreover, the results suggest that there may be a "preferred" configuration to process a specific crude. Opportunities for reductions in GHG emissions such as processing high quality crudes in low complexity refineries (hydroskimming and medium conversion) instead of deep conversion refineries could be investigated. However, these opportunities will be limited by the decreasing number of low complexity refineries in North America available to process these types of crude feedstocks. This serves as a reminder that the range of refinery emissions for OS products, as for other crudes, is linked to refining industry investments made over the next decade.

This analysis substantiates the claim that more accurate assessments of refinery emissions are required to better inform LC-based policies and avoid potential unintended consequences. Putting the refinery emissions variations into context, the variability in GHG emissions in the refining stage that results from processing crudes of different qualities is as significant as the magnitude expected in upstream operations (e.g., in this paper, the variability is up to 14 g CO_2eq/MJ of crude, or up to 11 g CO_2eq/MJ of gasoline and 19 CO_2eq/MJ of diesel—based on the full range of base case crudes). If crudes are run through the same configuration, refinery performance (defined by efficiency of energy use) introduces important variation. The PRELIM application demonstrated up to 43% deviation in the GHG emissions burden attributed to a crude solely by varying the efficiency of the process units in one configuration. This implies that impacts of crude quality and refinery configuration should be modeled in the refining stage of LC analyses of petroleum-based fuels. Also, climate policies based on LCA should equally engage both parts of the supply chain (i.e., crude production/processing/transport and refining stages) to encourage the most cost-effective GHG emissions mitigation pathways. Directives such as the current High Carbon Intensity Crude Oil (HCICO) provision in the CA-LCFS that do not explicitly include these differences in the definition and principles/goals could lead to unintended consequences.[50,51]

The results also show that API gravity and sulfur content of the whole crude are not sufficient to characterize the refinery energy use and GHG emissions specific to a crude. The use of these simple metrics within policies that are intended to differentiate the LC emissions of different crudes can also lead to unintended consequences. Energy efficiency of the process units and refinery configuration play a large role in explaining the variation in possible estimates. Ideally, the assay data like those presented in PRELIM should be collected and used as it improves accuracy beyond whole crude properties. However, since these data tend to be highly proprietary, we recommend that at minimum the crude distillation curve and the hydrogen content of the crude fractions be accounted for. Future efforts should focus on striking the balance between reporting the best data in a transparent way and protecting sensitive information. A starting point could be exploring the use of refining industry data and methods such as the Nelson index and/or Solomon energy efficiency index to simplify the characterization of refinery configurations;[52−55] however, an innovative approach will also be needed to represent crude quality parameters.

The PRELIM application shown in this paper demonstrates the strengths of detailed process modeling for understanding and assessing petroleum refinery GHG emissions sources with the ultimate goal of more informed decisions regarding the increased use of heavy oil in North America.

■ ASSOCIATED CONTENT

Ⓢ Supporting Information

Details on literature review, methods, and results. This material is available free of charge via the Internet at http://pubs.acs.org.

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Notes

The authors declare no competing financial interest.

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Crude Oil Assay Inventory [excerpts from "Prelim" database (www.ucalgary.ca/lcaost/prelim)] Page 1 of 4.

Brazil Lula_BG Group											
Assay #	57	**Cutoff Temp [°C]**	80	180	290	340	400	450	525	525	400
Property	Units	**Full Crude**	**LSR**	**Naphtha**	**Kerosene**	**Diesel**	**AGO**	**LVGO**	**HVGO**	**VR**	**AR**
Vol Flow	bpd	102,092	5,809	12,644	18,066	9,143	15,922	15,611	17,313	7,584	40,510
Vol Flow	m^3/d	16,232.60	924	2,010	2,872	1,454	2,532	2,482	2,753	1,206	6,441
Mass Flow	kg/d	13,995,180	629,783	1,539,470	2,379,181	1,259,566	2,239,229	2,239,229	2,519,132	1,119,614	5,877,976
Sulphur	wt%	0.27	0.05	0.00	0.11	0.22	0.30	0.38	0.44	0.50	0.43
Nitrogen	mass ppm	1119.63	0.0	0.0	83.2	449.2	856.4	1572.4	2390.9	3076.09	2209.6
API gravity	oAPI	29.3	75.81	53.10	39.17	31.65	28.32	25.20	22.97	20.76	23.40
Density	kg/m^3	880.20	681.88	765.77	828.27	866.43	884.50	902.13	915.14	928.44	912.57
Hydrogen	wt%	12.74	15.00	13.86	13.08	12.69	12.53	12.39	12.29	12.19	12.31
MCR	wt%	3.24								40.46	7.71
Characterization Factor	Kw (Approximate)	11.78	12.23	11.80	11.82	11.75	11.86	11.92	12.11	12.61	12.27
Tb(50%) weight basis	[°C]	345.00	50	138	250	315	370	420	485	620	510

Iraq Basra_BP											
Assay #	30	**Cutoff Temp [°C]**	80	180	290	340	400	450	525	525	400
Property	Units	**Full Crude**	**LSR**	**Naphtha**	**Kerosene**	**Diesel**	**AGO**	**LVGO**	**HVGO**	**VR**	**AR**
Vol Flow	bpd	101,031	9,036	16,592	15,984	7,981	8,678	7,522	9,221	26,016	42,683
Vol Flow	m^3/d	16,063.93	1,437	2,638	2,541	1,269	1,380	1,196	1,466	4,137	6,787
Mass Flow	kg/d	13,904,550	973,319	1,946,637	2,085,683	1,112,364	1,251,410	1,112,364	1,390,455	4,032,320	6,535,139
Sulphur	wt%	2.66	0.00	0.00	1.23	2.17	2.81	3.40	3.93	4.77	4.36
Nitrogen	mass ppm	798.48	0.0	0.0	28.1	294.8	558.3	856.9	1192.2	1836.77	1532.8
API gravity	oAPI	30.16192967	77.16	60.08	40.75	29.76	24.37	20.50	17.56	13.52	15.30
Density	kg/m^3	874.5	677.46	737.87	820.68	876.60	906.91	930.01	948.35	974.80	962.94
Hydrogen	wt%	12.52	15.54	14.48	13.16	12.93	12.28	11.81	11.48	11.03	11.26
MCR	wt%	6.33								21.81	13.47
Characterization Factor	Kw (Approximate)	12.06	12.44	12.12	11.74	11.58	11.57	11.62	11.74	12.05	11.90
Tb(50%) weight basis	[°C]	380	60	125	225	310	370	430	495	630	565

Albian Heavy Synthetic_Crude Monitor	SCO,So,H	AHS	Stream								
Assay #	1	**Cutoff Temp [°C]**	84.466	177.726	282.468	342.062	394.806	452.558	522.148	522.148	394.806
Property	Units	**Full Crude**	**LSR**	**Naphtha**	**Kerosene**	**Diesel**	**AGO**	**LVGO**	**HVGO**	**VR**	**AR**
Vol Flow	bpd	99,920	5,637	10,225	12,286	7,233	9,877	10,428	13,761	30,473	53,967
Vol Flow	m^3/d	15,887.23	896	1,626	1,953	1,150	1,570	1,658	2,188	4,845	8,581
Mass Flow	kg/d	14,886,832	595,473	1,190,947	1,637,552	1,042,078	1,488,683	1,637,552	2,233,025	5,061,523	8,932,099
Sulphur	wt%	2.24	0.00	0.26	1.09	1.43	1.64	1.93	2.39	3.72	3.06
Nitrogen	mass ppm	2581.33	0.0	0.0	29.0	733.4	1390.2	2203.4	3116.3	4935.20	3979.6
API gravity	oAPI	19.48134328	81.26	61.48	37.13	24.51	17.62	11.64	7.01	3.82	4.30
Density	kg/m^3	936.2787443	664.43	732.53	838.28	906.09	947.98	987.60	1020.58	1044.65	1040.95
Hydrogen	wt%	10.72	16.01	14.76	12.88	12.19	11.21	10.30	9.57	8.65	9.18
MCR	wt%	10.90078261								32.03	18.17
Characterization Factor	Kw (Approximate)	11.64	12.64	12.28	11.65	11.28	11.08	10.94	10.88	11.30	10.95
Tb(50%) weight basis	[°C]	447.934	56.754	131.97	245.37	321.318	372.956	429.496	490.614	643.4122449	551.7

Crude Oil Assay Inventory [excerpts from "Prelim" database (www.ucalgary.ca/lcaost/prelim)] Page 2 of 4.

Cold Lake_Crude Monitor	Dilbit	CL	Stream								
Assay#	4	**Cutoff Temp [°C]**	84.85108696	172.373913	284.0402174	341.4423913	395.0586957	451.2565217	519.0554348	519.0554348	395.0586957
Property	Units	**Full Crude**	**LSR**	**Naphtha**	**Kerosene**	**Diesel**	**AGO**	**LVGO**	**HVGO**	**VR**	**AR**
Vol Flow	bpd	101,435	12,417	8,818	10,710	7,073	8,875	7,778	10,529	35,235	52,917
Vol Flow	m^3/d	16,128.13	1,974	1,402	1,703	1,125	1,411	1,237	1,674	5,602	8,414
Mass Flow	kg/d	14,764,716	1,181,177	1,033,530	1,476,472	1,033,530	1,328,824	1,181,177	1,624,119	5,905,886	8,711,183
Sulphur	wt%	3.89	0.00	0.09	1.43	2.09	2.61	3.14	3.91	6.68	5.68
Nitrogen	mass ppm	2200.95	0.0	0.0	28.7	249.6	550.6	956.1	1665.5	4678.43	3612.0
API gravity	oAPI	20.73007813	104.79	60.26	31.53	22.32	18.61	16.51	14.21	2.60	5.04
Density	kg/m^3	928.598502	598.26	737.16	867.07	918.99	941.72	955.07	970.18	1054.17	1035.34
Hydrogen	wt%	11.19	18.86	14.71	12.21	11.84	11.38	11.14	10.90	8.72	9.46
MCR	wt%	10.62700535								26.54	18.01
Characterization Factor	Kw (Approximate)	11.79	13.92	12.28	11.28	11.12	11.17	11.29	11.45	11.27	11.25
Tb(50%) weight basis	[°C]	457.673913	48.50217391	140.3641304	248.6804348	320.6956522	375.2913043	426.2891304	490.5913043	661.786747	606.8086957

Husky Synthetic Blend_Crude Monitor	SCO,Sw,L	HSB	Stream								
Assay #	5	**Cutoff Temp [°C]**	91.20833333	177.4222222	290.6416667	342.6805556	399.6166667	455.0166667	526.4805556	526.4805556	399.6166667
Property	Units	**Full Crude**	**C5s**	**Naphtha**	**Kerosene**	**Diesel**	**AGO**	**LVGO**	**HVGO**	**VR**	**AR**
Vol Flow	bpd	99,990	3,733	7,964	27,113	18,871	18,284	14,035	8,214	1,778	24,110
Vol Flow	m^3/d	15,898.46	594	1,266	4,311	3,000	2,907	2,232	1,306	283	3,833
Mass Flow	kg/d	13,694,379	410,831	958,607	3,560,539	2,601,932	2,601,932	2,054,157	1,232,494	273,888	3,560,539
Sulphur	wt%	0.09	0.06	0.04	0.02	0.05	0.09	0.18	0.31	0.10	0.22
Nitrogen	mass ppm	349.74	0.0	0.0	40.4	191.4	401.4	726.2	1200.7	481.00	871.6
API gravity	oAPI	32.62820513	72.74	55.23	39.65	31.51	26.44	22.07	18.29	14.39	20.69
Density	kg/m^3	861.2817181	692.12	757.05	825.94	867.19	895.02	920.52	943.71	968.97	928.81
Hydrogen	wt%	12.87	15.04	14.17	13.20	13.20	12.59	12.05	11.58	11.95	11.88
MCR	wt%	0.060416667								3.02	0.23
Characterization Factor	Kw (Approximate)	11.91	12.21	12.02	11.84	11.76	11.73	11.72	11.73	11.78	11.72
Tb(50%) weight basis	[°C]	328.7472222	63.38611111	147.2138889	248.0277778	317.9638889	371.325	426.3777778	483.4305556	556.5055556	445.8944444

Seal Heavy_Crude Monitor	Dilbit	SH	Stream								
Assay #	14	**Cutoff Temp [°C]**	80.33214286	169.3714286	284.4464286	339.6821429	393.9107143	452.5214286	522.175	522.175	393.9107143
Property	Units	**Full Crude**	**LSR**	**Naphtha**	**Kerosene**	**Diesel**	**AGO**	**LVGO**	**HVGO**	**VR**	**AR**
Vol Flow	bpd	100,406	8,855	11,207	12,947	6,102	7,918	6,785	8,565	38,026	51,478
Vol Flow	m^3/d	15,964.55	1,408	1,782	2,059	970	1,259	1,079	1,362	6,046	8,185
Mass Flow	kg/d	14,774,632	886,478	1,329,717	1,772,956	886,478	1,181,971	1,034,224	1,329,717	6,353,092	8,717,033
Sulphur	wt%	5.14	0.00	0.14	2.14	2.98	3.54	4.18	4.90	8.55	7.47
Nitrogen	mass ppm	1978.54	0.0	0.0	0.0	195.3	447.3	842.0	1363.8	4068.27	3273.0
API gravity	oAPI	20.62790698	93.01	57.94	32.64	23.23	19.08	15.96	13.27	3.03	1.23
Density	kg/m^3	929.2221612	629.65	746.20	861.24	913.62	938.79	958.65	976.44	1050.77	1065.00
Hydrogen	wt%	10.60	17.27	14.33	12.29	11.98	11.44	11.06	10.73	7.95	8.75
MCR	wt%	9.384722222								21.80	15.91
Characterization Factor	Kw (Approximate)	11.83	13.18	12.06	11.31	11.15	11.18	11.28	11.37	11.41	11.05
Tb(50%) weight basis	[°C]	467.3321429	45.29285714	133.3464286	241.3892857	316.3535714	370.8142857	430.8428571	490.1857143	686.975	636.0678571

Crude Oil Assay Inventory [excerpts from "Prelim" database (www.ucalgary.ca/lcaost/prelim)] Page 3 of 4.

Suncor Synthetic A_Crude Monitor	SCO,Sw,L	OSA	Stream								
Assay #	12	**Cutoff Temp [°C]**	84.84210526	179.5368421	289.4052632	343.9342105	400.3657895	457.1710526	533.7842105	533.7842105	400.3657895
Property	Units	**Full Crude**	**C5s**	**Naphtha**	**Kerosene**	**Diesel**	**AGO**	**LVGO**	**HVGO**	**VR**	**AR**
Vol Flow	bpd	99,885	4,978	14,653	24,626	19,472	18,874	11,929	4,474	880	17,328
Vol Flow	m^3/d	15,881.76	791	2,330	3,916	3,096	3,001	1,897	711	140	2,755
Mass Flow	kg/d	13,654,443	546,178	1,775,078	3,277,066	2,730,889	2,730,889	1,775,078	682,722	136,544	2,594,344
Sulphur	wt%	0.16	0.01	0.01	0.04	0.13	0.23	0.38	0.62	0.10	0.43
Nitrogen	mass ppm	488.71	8.9	3.8	125.9	381.6	686.7	1147.4	1832.1	321.13	1284.1
API gravity	oAPI	33.10824742	73.34	54.04	37.40	28.76	23.84	19.55	15.78	13.28	18.63
Density	kg/m^3	858.769987	690.10	761.88	836.93	882.08	910.00	935.85	959.81	976.36	941.61
Hydrogen	wt%	12.70	14.95	13.94	12.90	12.81	12.20	11.65	11.16	11.82	11.53
MCR	wt%	0.022916667								2.29	0.12
Characterization Factor	Kw (Approximate)	11.86	12.16	11.89	11.66	11.56	11.53	11.52	11.55	11.59	11.53
Tb(50%) weight basis	[°C]	315.0105263	55.72368421	141.1657895	244.1210526	317.6631579	370.1263158	425.6421053	485.5868421	533.7842105	439.1921053

Syncrude Synthetic_Crude Monitor	**SCO,Sw,L**	**SYN, SSB**	**Stream**								
Assay #	17	**Cutoff Temp [°C]**	80.04	177.08	290.64	342.22	397.58	451.91	521.41	521 +	398 +
Property	Units	**Full Crude**	**C5s**	**Naphtha**	**Kerosene**	**Diesel**	**AGO**	**LVGO**	**HVGO**	**VR**	**AR**
Vol Flow	bpd	99,796	3,703	12,478	26,897	16,704	16,206	13,004	8,161	2,643	23,893
Vol Flow	m^3/d	15,867.60	589	1,984	4,277	2,656	2,577	2,068	1,298	420	3,799
Mass Flow	kg/d	13,786,921	413,608	1,516,561	3,584,599	2,343,777	2,343,777	1,930,169	1,240,823	413,608	3,584,599
Sulphur	wt%	0.14	0.01	0.00	0.01	0.08	0.16	0.29	0.48	0.35	0.36
Nitrogen	mass ppm	487.44	0.0	0.0	45.1	271.1	570.4	1015.9	1702.5	1240.05	1279.4
API gravity	oAPI	31.5	69.73	53.44	37.15	28.69	23.91	19.93	16.32	12.13	18.31
Density	kg/m^3	867.10	702.50	764.37	838.19	882.45	909.58	933.52	956.28	984.19	943.58
Hydrogen	wt%	12.55	14.63	13.84	12.86	12.80	12.21	11.70	11.24	11.30	11.49
MCR	wt%	0.05								1.72	0.20
Characterization Factor	Kw (Approximate)	11.78	12.02	11.83	11.64	11.56	11.54	11.54	11.56	11.65	11.55
Tb(50%) weight basis	[°C]	320.99	63	139	244	318	370	423	480	566	447

Western Canadian Select_Crude Monitor	Syndilbit	WCS	**Stream**								
Assay #	20	**Cutoff Temp [°C]**	78.62	175.17	289.93	339.77	393.55	451.35	524.06	524 +	394 +
Property	Units	**Full Crude**	**LSR**	**Naphtha**	**Kerosene**	**Diesel**	**AGO**	**LVGO**	**HVGO**	**VR**	**AR**
Vol Flow	bpd	100,306	6,197	8,855	13,033	9,199	8,974	8,841	10,648	34,559	53,786
Vol Flow	m^3/d	15,948.60	985	1,408	2,072	1,463	1,427	1,406	1,693	5,495	8,552
Mass Flow	kg/d	14,783,214	591,329	1,034,825	1,773,986	1,330,489	1,330,489	1,330,489	1,626,154	5,765,453	8,722,096
Sulphur	wt%	3.38	0.00	0.26	0.96	1.52	1.99	2.53	3.24	6.01	4.97
Nitrogen	mass ppm	1998.50	0.0	0.0	49.5	221.6	468.9	844.2	1457.9	4343.75	3271.9
API gravity	oAPI	20.5	104.04	60.83	33.63	23.90	20.11	17.86	15.67	3.23	7.10
Density	kg/m^3	929.76	600.16	734.98	856.08	909.67	932.42	946.44	960.52	1049.25	1019.89
Hydrogen	wt%	11.21	18.75	14.76	12.40	12.07	11.60	11.36	11.13	9.12	9.84
MCR	wt%	9.36								23.97	15.86
Characterization Factor	Kw (Approximate)	11.74	13.87	12.30	11.37	11.19	11.24	11.37	11.52	11.35	11.37
Tb(50%) weight basis	[°C]	451.35	48	138	240	314	369	422	482	668	595

Crude Oil Assay Inventory [excerpts from "Prelim" database (www.ucalgary.ca/lcaost/prelim)] Page 4 of 4.

Alaskan North Slope_Exxon	Conv,So,L	ANS									
Assay #	23	**Cutoff Temp [°C]**	80.00	178.00	287.00	342.00	399.00	450.00	523.00	523 +	399 +
Property	Units	**Full Crude**	**LSR**	**Naphtha**	**Kerosene**	**Diesel**	**AGO**	**LVGO**	**HVGO**	**VR**	**AR**
Vol Flow	bpd	101,197	9,489	17,342	16,512	7,858	7,690	6,626	8,420	27,259	42,843
Vol Flow	m^3/d	16,090.29	1,509	2,757	2,625	1,249	1,223	1,054	1,339	4,334	6,812
Mass Flow	kg/d	13,810,740	966,752	2,071,611	2,209,718	1,104,859	1,104,859	966,752	1,242,967	4,143,222	6,352,940
Sulphur	wt%	0.85	0.00	0.00	0.25	0.59	0.85	1.12	1.39	1.63	1.50
Nitrogen	mass ppm	908.14	0.0	0.0	36.4	355.7	673.2	1071.1	1548.1	2018.95	1782.6
API gravity	oAPI	31.4	89.12	56.66	36.45	28.35	24.95	22.55	20.76	16.38	20.07
Density	kg/m^3	868.60	640.75	751.29	841.68	884.31	903.56	917.61	928.42	955.94	932.61
Hydrogen	wt%	12.81	16.24	14.37	13.30	12.94	12.72	12.41	11.91	11.34	11.61
MCR	wt%	4.86								16.18	10.57
Characterization Factor	Kw (Approximate)	11.67	12.81	11.88	11.50	11.51	11.61	11.74	11.89	12.24	11.96
Tb(50%) weight basis	[°C]	305.61	35	123	232	315	370	424	477	620	500

Attachment KR–5

U.S. Chemical Safety and Hazard Investigation Board, 2013. Interim Investigation Report: Chevron Richmond Refinery Fire. Final Report adopted 19 April 2013. (Incorporated by reference in CBE supp. technical comments of 15 Sep 2014.)

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*.

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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.

[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]

[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

[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]

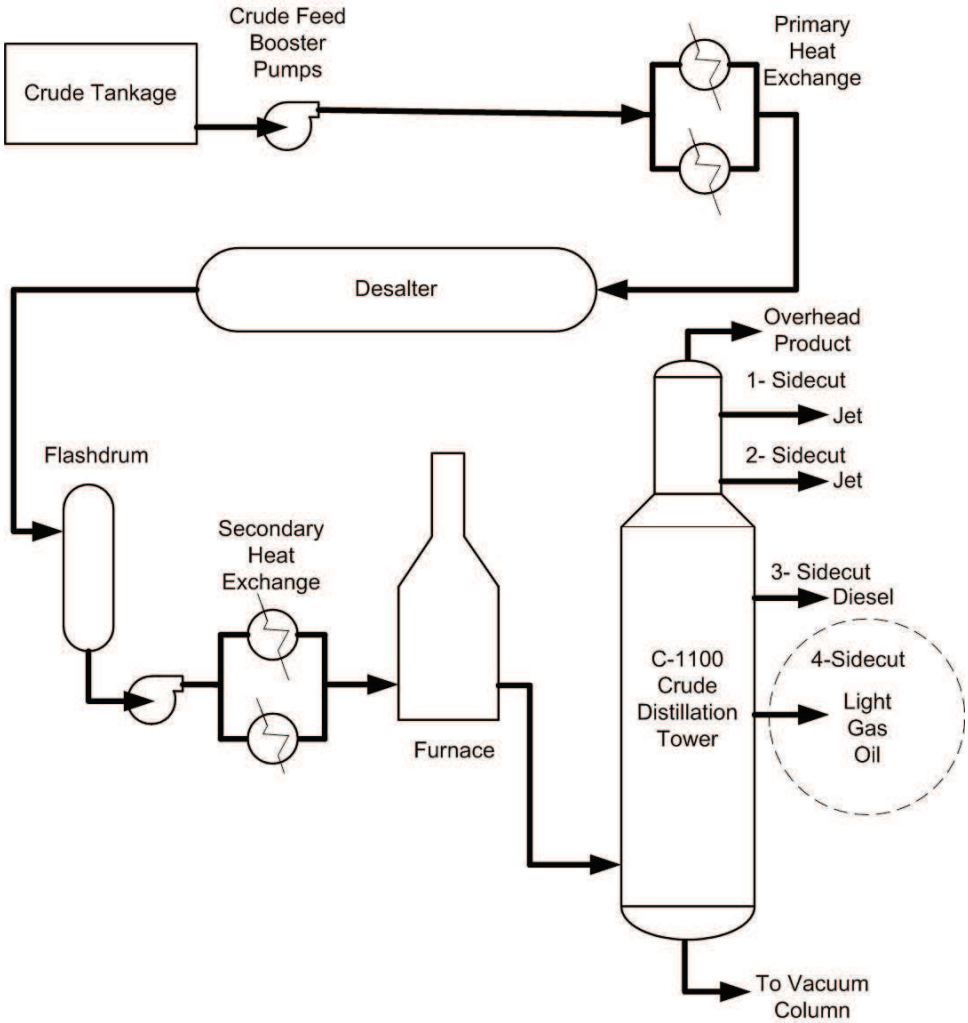

Figure 4. C-1100 Crude Unit Atmospheric Column and Upstream Process Equipment.

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

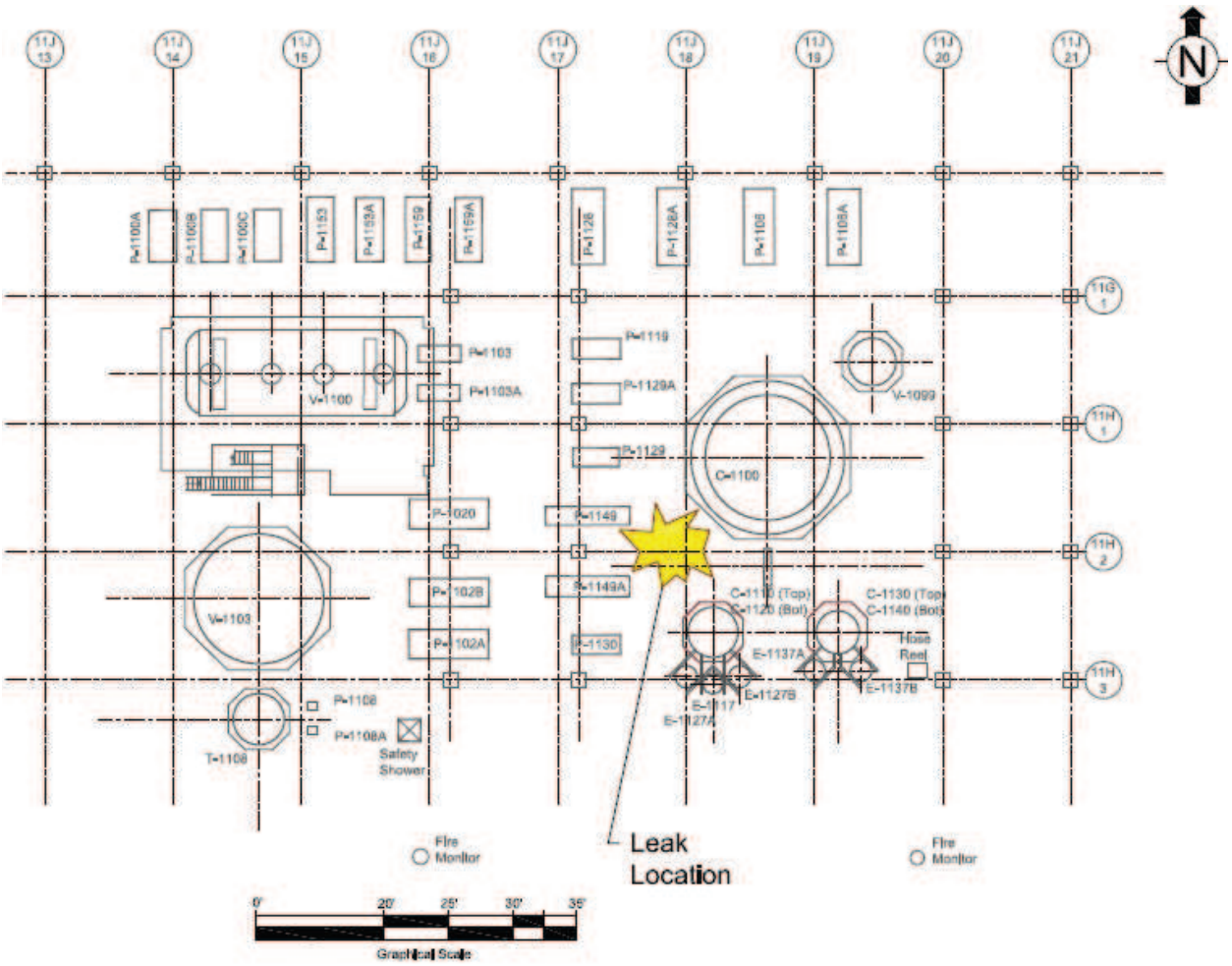

Figure 5. Overhead view of the equipment in the #4 Crude Unit showing the leak location, commonly referred to as a plot plan.

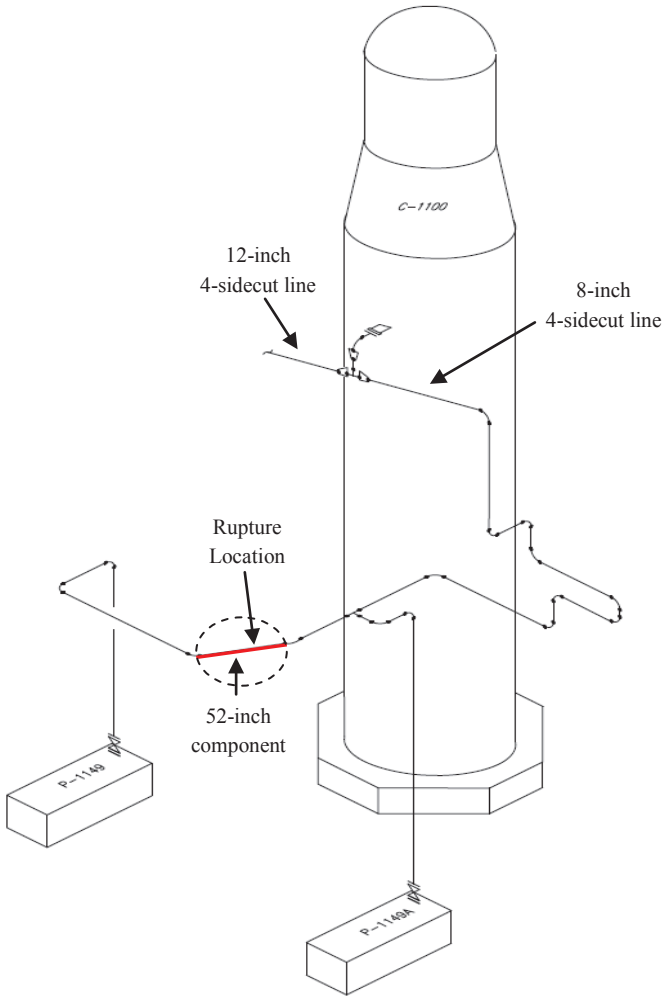

Figure 6. 4-sidecut line configuration and rupture location.

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.

[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

---

[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.

[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.

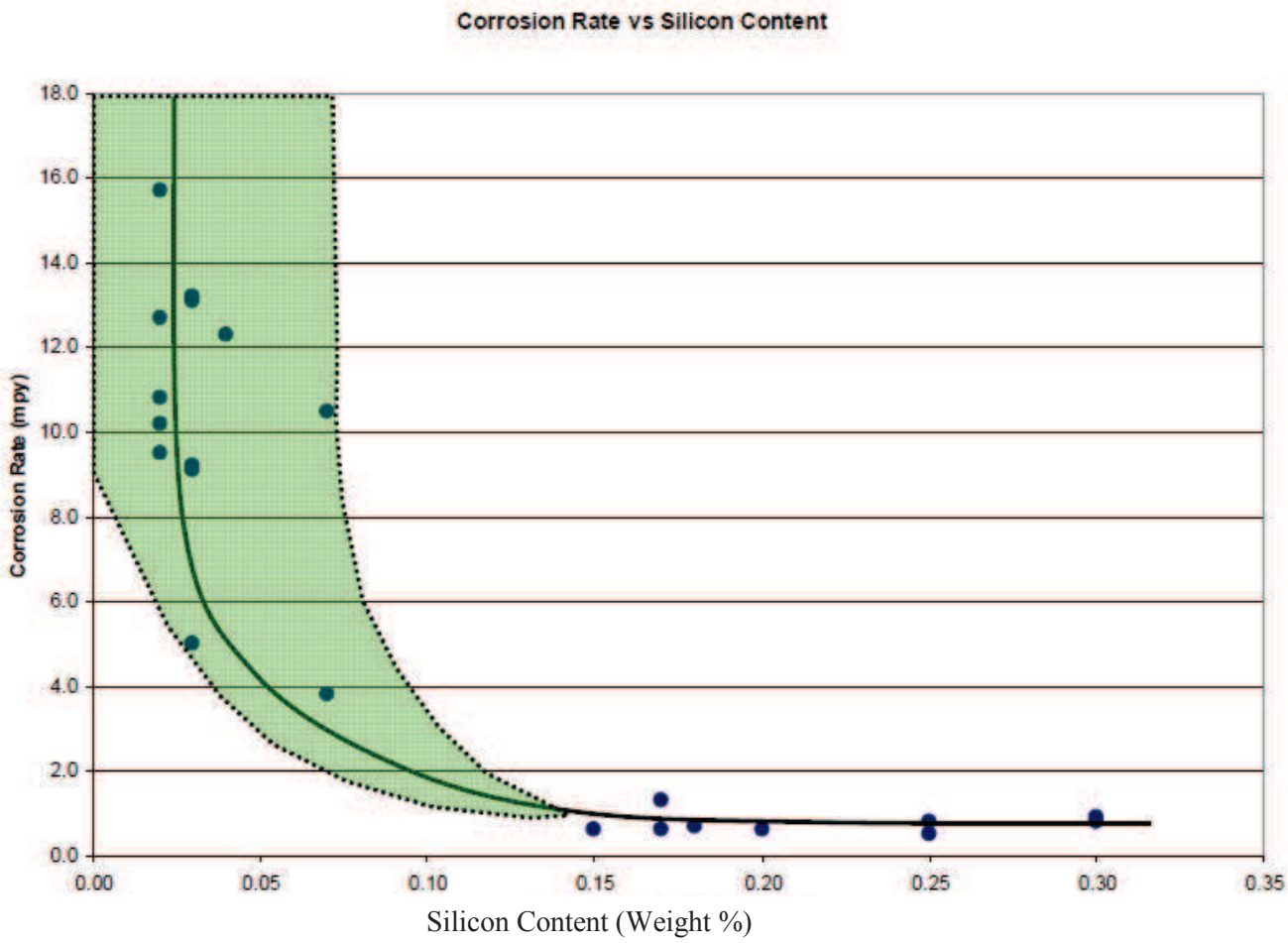

Figure 8. This graph shows how corrosion rates increase in carbon steel containing decreasing percentages of silicon. This information can be found in Annex C of API RP 939-C.[i]

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

[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).

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

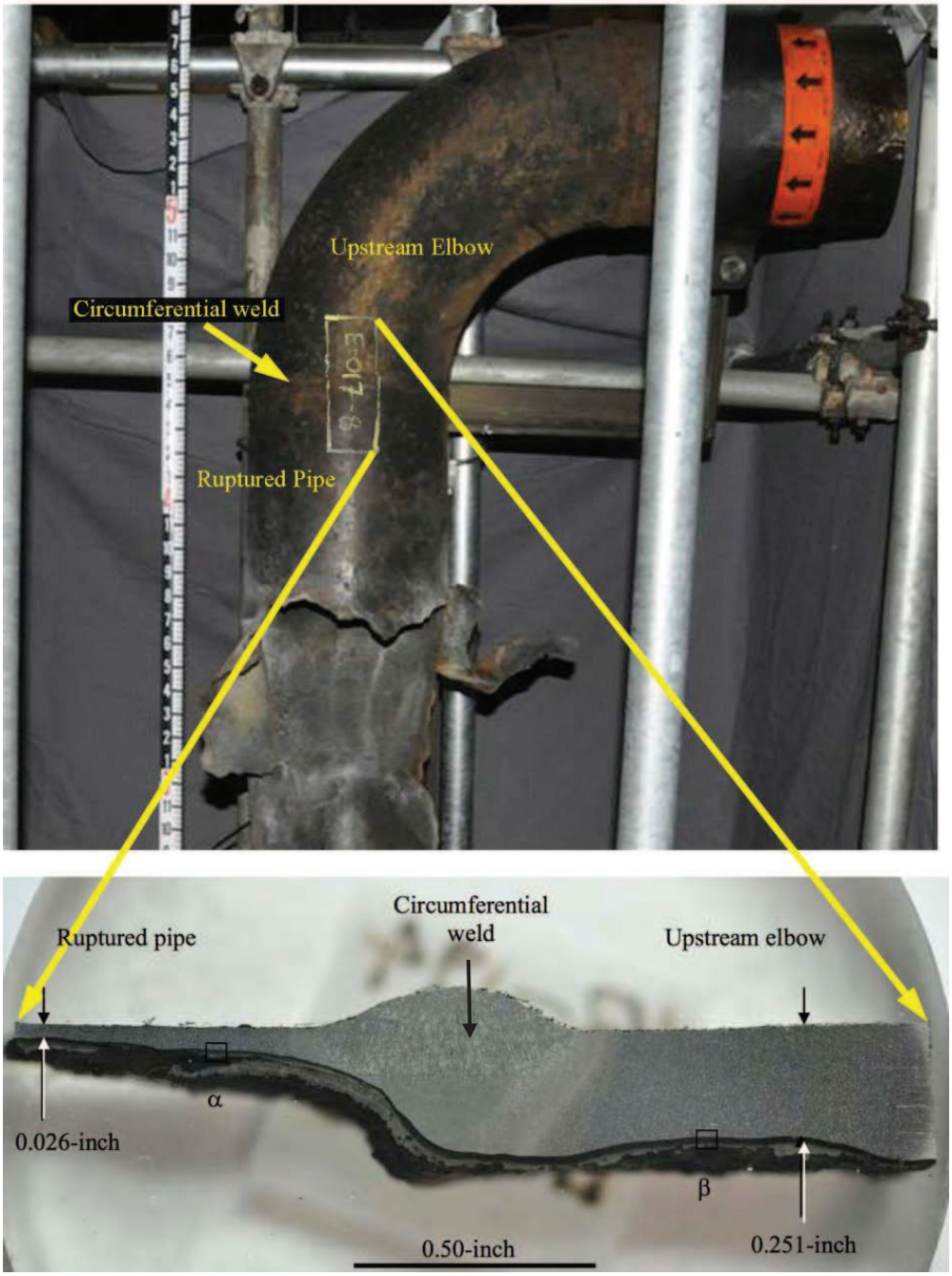

Figure 9. 4-sidecut piping sample (E-017-8) analyzed by Anamet Labs showing the relative thickness of low silicon piping on the left and the high silicon piping on the right. The ruptured pipe component (left) contained 0.01 % silicon and the upstream elbow component (right) contained 0.16 % silicon.[19]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

[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]

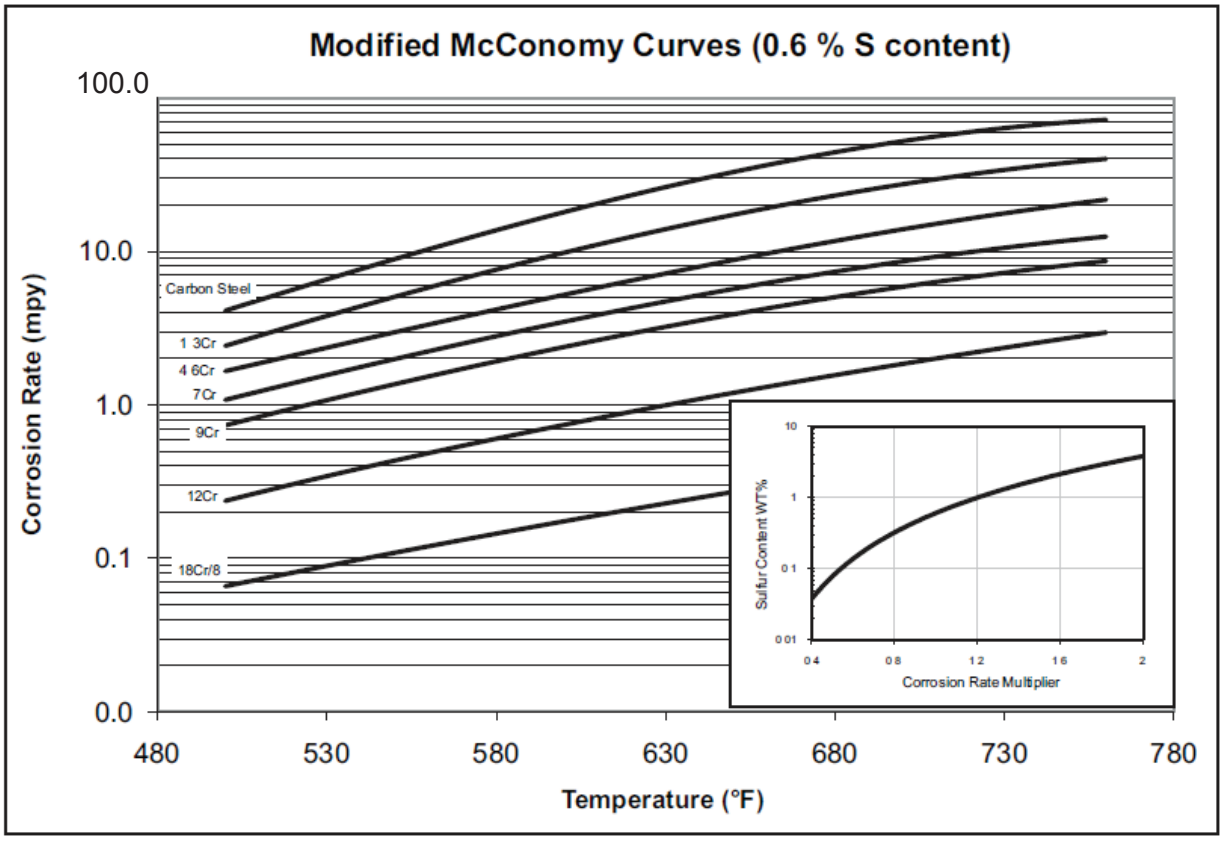

Figure 10. Modified McConomy Curves from API RP 939-C.

[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*.

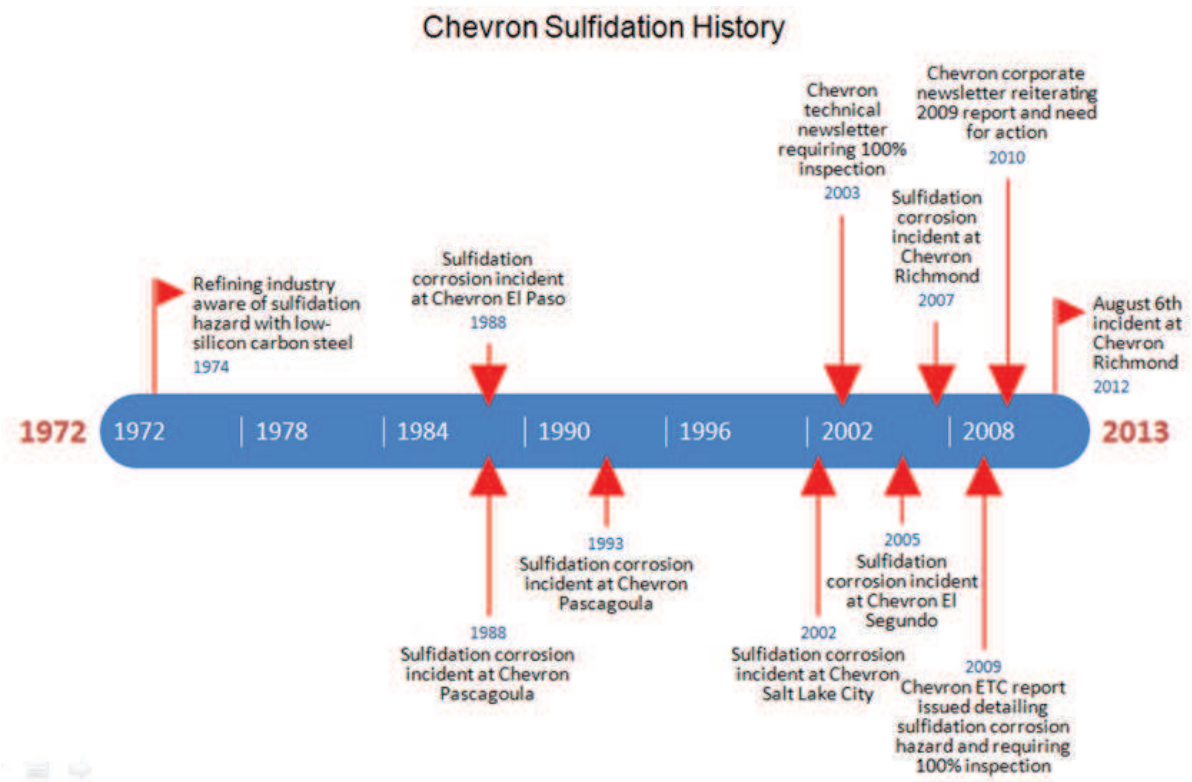

Figure 11. Chevron's key sulfidation events between 1974 and 2013.

[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.

[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]

[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.

[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.

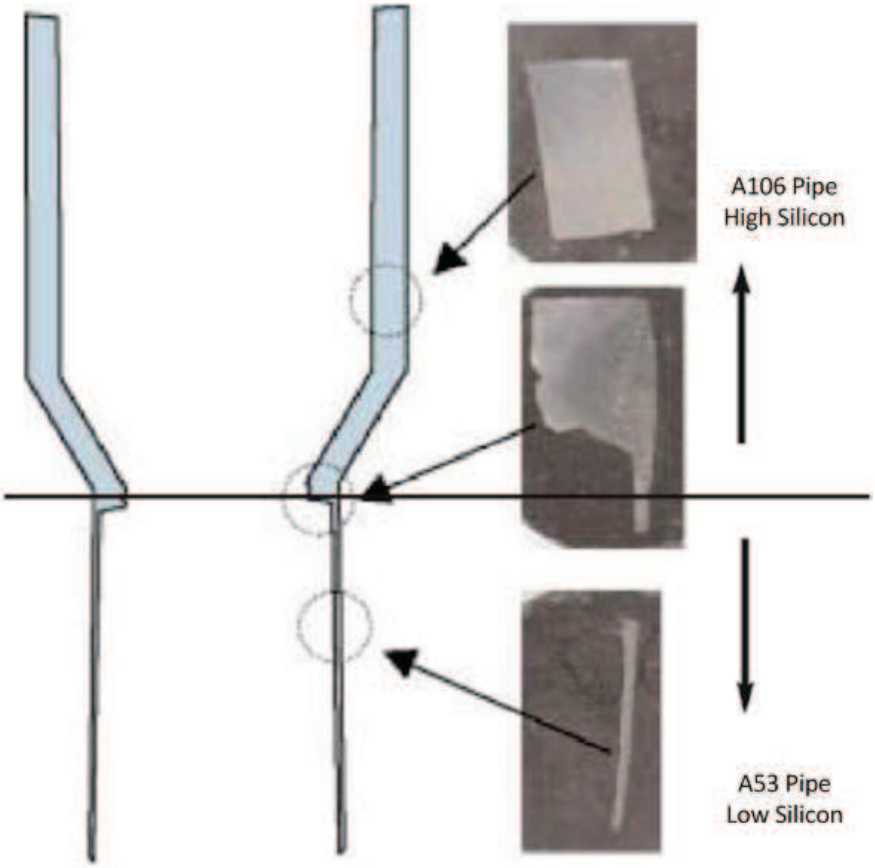

Figure 12. Schematic of failed piping from the Chevron Salt Lake Refinery. Similar to the Chevron Richmond Refinery incident, the failed piping contained low amounts of silicon and corroded significantly faster than adjacent piping components.

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.

[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).

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.

[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.

[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.

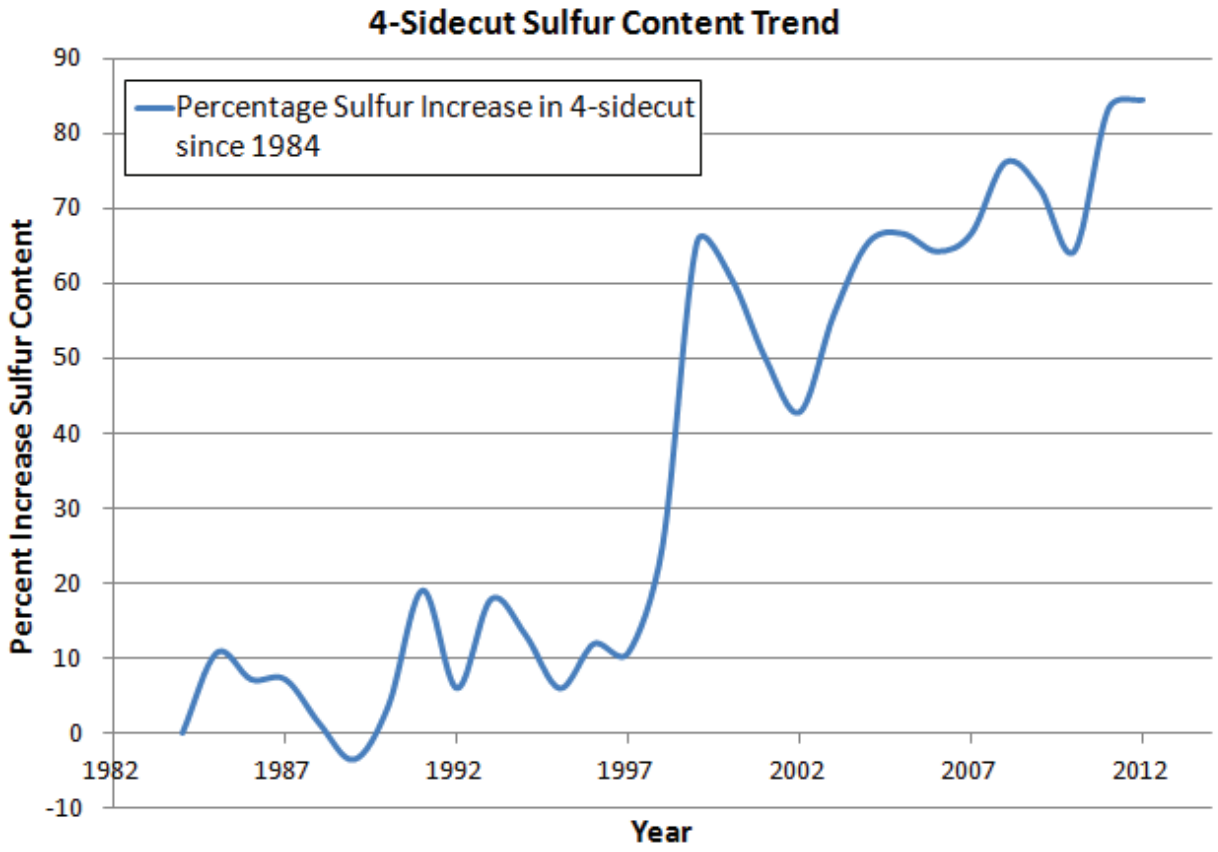

Figure 14. Graph shows the percentage increase from 1984 values of the sulfur content in the 4-sidecut.

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.

[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.

[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.

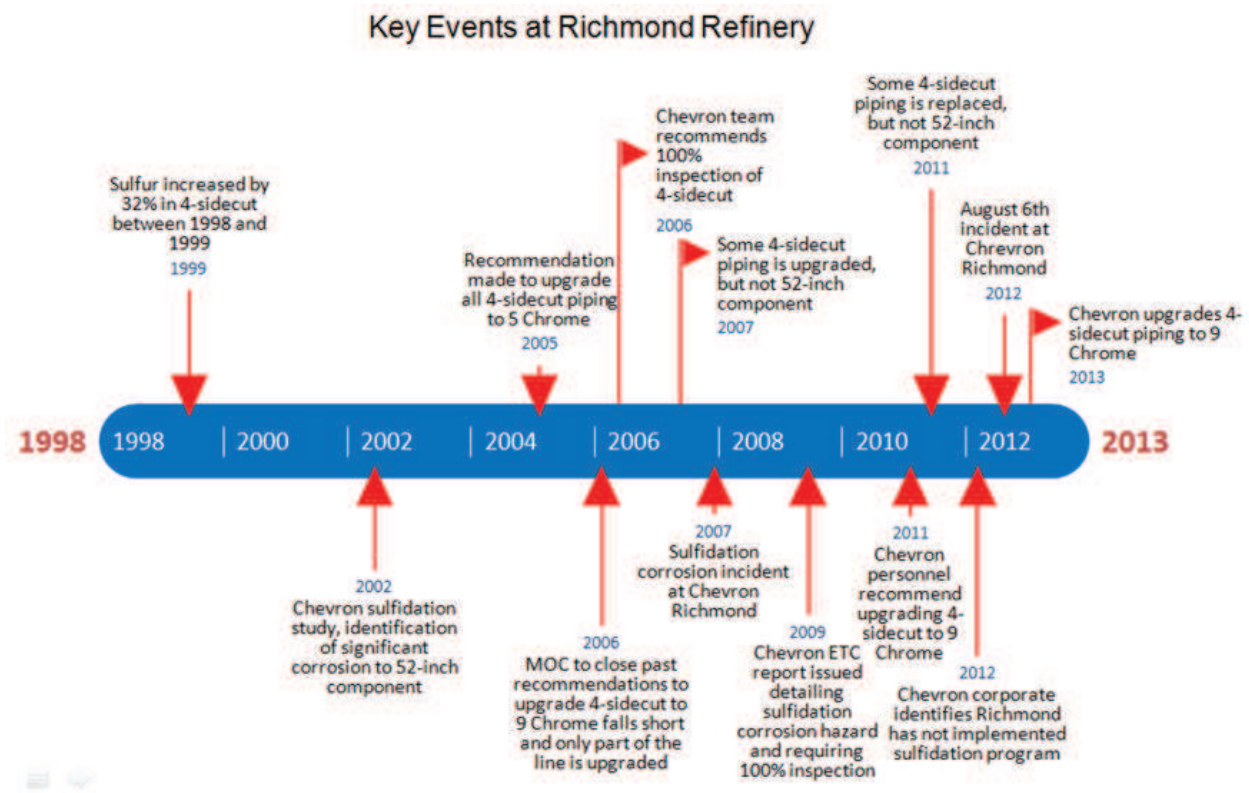

Figure 15. Key events at the Richmond refinery between 1998 and 2013.

[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.

[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.

[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.

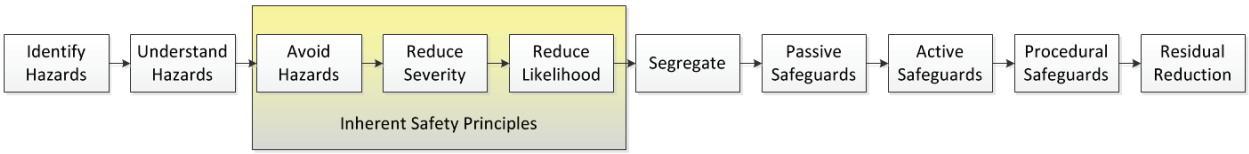

Figure 16. Hierarchy of controls. The boxes reflect inherently safer controls from left to right, based on *Process Plants: A Handbook for Inherently Safer Design Second Edition*; Kletz, Trevor Amyotte, Paul; CRC Press 2010.

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:

[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:

[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

[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]

[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

[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

[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]

[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

[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

[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

[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]

[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

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Date of Approval April __, 2013.

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99. Department of Industrial Relations, Division of Occupational Safety and Health, California, Process Safety Management District Office. "Mission Statement: Goals Reached in 2011 & Strategic Plan for 2012."

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Attachment KR–6

Excerpts from the Chevron Refinery Modernization Project Environmental Impact Report, State Clearinghouse No. 2011062042; Lead Agency: City of Richmond, CA. Excerpts include Appendix 4.3-URM: Unit Rate Model; and Six Element Test Reports: Quarterly reports including data gathered and reported for the year 2009. (Incorporated by reference in CBE supp. technical comments of 15 Sep 2014; previously re-submitted in part at the Planning Commission Hearing.)

Appendix 4.3 - URM

URM: Unit Rate Model

Turner, Mason & Company
CONSULTING ENGINEERS

February 26, 2014

Ms. Shari Libicki
Environ
201 California St. #1280
San Francisco, CA 94111

Re: EIR for the Chevron Richmond Refinery Revised Renewal Project - Unit Rate Model Development and Use

Dear Shari:

Turner, Mason & Co. was engaged by Environ to provide refinery technical expertise to the City of Richmond for the development of an environmental impact report (EIR) for the Chevron Richmond Revised Renewal Project. The major changes in the refinery associated with the project include:

1. Construction of a new hydrogen plant to replace the existing plant (approximately 244 mmscf/d replacing a nominal 170 mmscf/d),
2. Increase the capacity of the FCC FHT from 65,000 b/d to 80,000 b/d, and
3. Increase the capacity of the sulfur recovery units from a nominal 600 long tons per day (lt/d) to 900 lt/d.

In addition to other tasks, TM&C was asked to develop a refinery unit rate model (URM) to 1) determine process unit rates in the refinery related to the use of different crude oil input blends, as well as, 2) expected sulfur recovery rates based on the sulfur content of crude and gas oil used by the refinery, and 3) the hydrogen production that the refinery would use from the proposed new hydrogen plant. TM&C was also asked to conduct several URM runs that included a range of potential crude oil blend inputs, and crude and gas oil sulfur contents, under pre- and post- Modernization Project conditions. TM&C developed the URM and conducted several URM runs over the period 2011-2014. The primary sources used to develop the model include:

Chevron Transmittal # 1, Revision #1
Chevron Transmittal #3C Rev. #2
Robert A Meyers, Handbook of Petroleum Refining Processes, Third Edition, (McGraw-Hill, 2004) page 10.27 and page 14.36.
M. D. Edgar, A. D. Johnson, J. T. Pistorius and T. Varadi, “Troubleshooting on Hydrotreating Units,” National Petroleum Refiners Association Meeting, paper no. AM-84-38, page 7 (1984).

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The technical report describing the URM, and several pre- and post- Modernization Project URM runs, is attached to this letter. The report accurately describes the URM, and accurately summarizes the URM results TM&C obtained for each of the scenarios in the report.

Sincerely,

Thomas R. Hogan
Senior Vice President
Turner, Mason & Co

APPENDIX 4.3
URM: UNIT RATE MODEL TECHNICAL APPENDIX

4.1 OVERVIEW

This technical appendix describes the unit rate model (URM) that was developed to estimate how the Chevron Richmond Refinery's (Facility's) processing units could potentially be used under post-Modernization Project conditions. The URM generates estimates of the daily average throughput or production of various Facility process units in relation to: (a) the amount of crude and gas oil inputs into the Facility; (b) the API gravity and fractional characteristics[1] of the crude oil inputs; and (c) the sulfur content of the crude and gas oil inputs.

Information used in the model was derived from the Facility's average daily operational activity and crude and gas oil inputs for the 3-year period 2008-2010 (the "Baseline Period"). The Baseline Period data was utilized to estimate how crude oil fractions and externally sourced, or purchased, gas oil would be allocated to specific process units. Applicable process unit throughputs were adjusted in the URM to reflect proposed post-Modernization Project permit limits, including a reduction in the permitted throughput limit of the Facility's solvent de-asphalting (SDA) unit to an annual average of 50,000 barrels per day (b/d).

The URM was designed to determine the volume of gas oil purchased by the Facility based on: (a) the amount of gas oil obtained from the crude oil blend used by the Facility; and (b) the percentage of total permitted gas oil capacity used by the five units that can initially process purchased gas oil in the Facility (the "gas oil gateway units"). As discussed below, the air quality analysis in the EIR considers URM cases that maximize total crude and gas oil use assuming that the crude and gas oil gateway units operate at 100% and 93% of post-Modernization Project permitted capacity.[2] The Facility did not operate at 100%

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[1] As discussed in Chapter 4.0 of this EIR, crude oil is input to the Facility and distilled in the crude unit into specific fractions of oil defined by boiling temperatures. The phrase "fractional characteristics" refers to the relative proportion of each fraction in the crude oil that enters the Facility crude unit.

[2] A 93% utilization rate is used in the Modernization Project EIR based on annual refinery utilization data for the western Unites States (Petroleum Administration Defense District Region V, or "PADD V") by the U.S. Energy Information Administration (EIA). Annual average PADD V refinery utilization rates are available for 1985-2012 (http://www.eia.gov/dnav/pet/pet_pnp_unc_dcu_r50_a.htm, accessed February 17, 2014) and averaged approximately 86.7% per year over this period. The highest annual average

or 93% of existing capacity during the entire Baseline Period, and for a variety of reasons refineries typically do not, or are not able to continuously operate at full capacity for annual durations. As a result, the URM results based on 100% and 93% crude unit and gas oil gateway unit capacity utilization provide a conservative estimate of the extent to which the Facility could be operated under post-Modernization Project conditions.

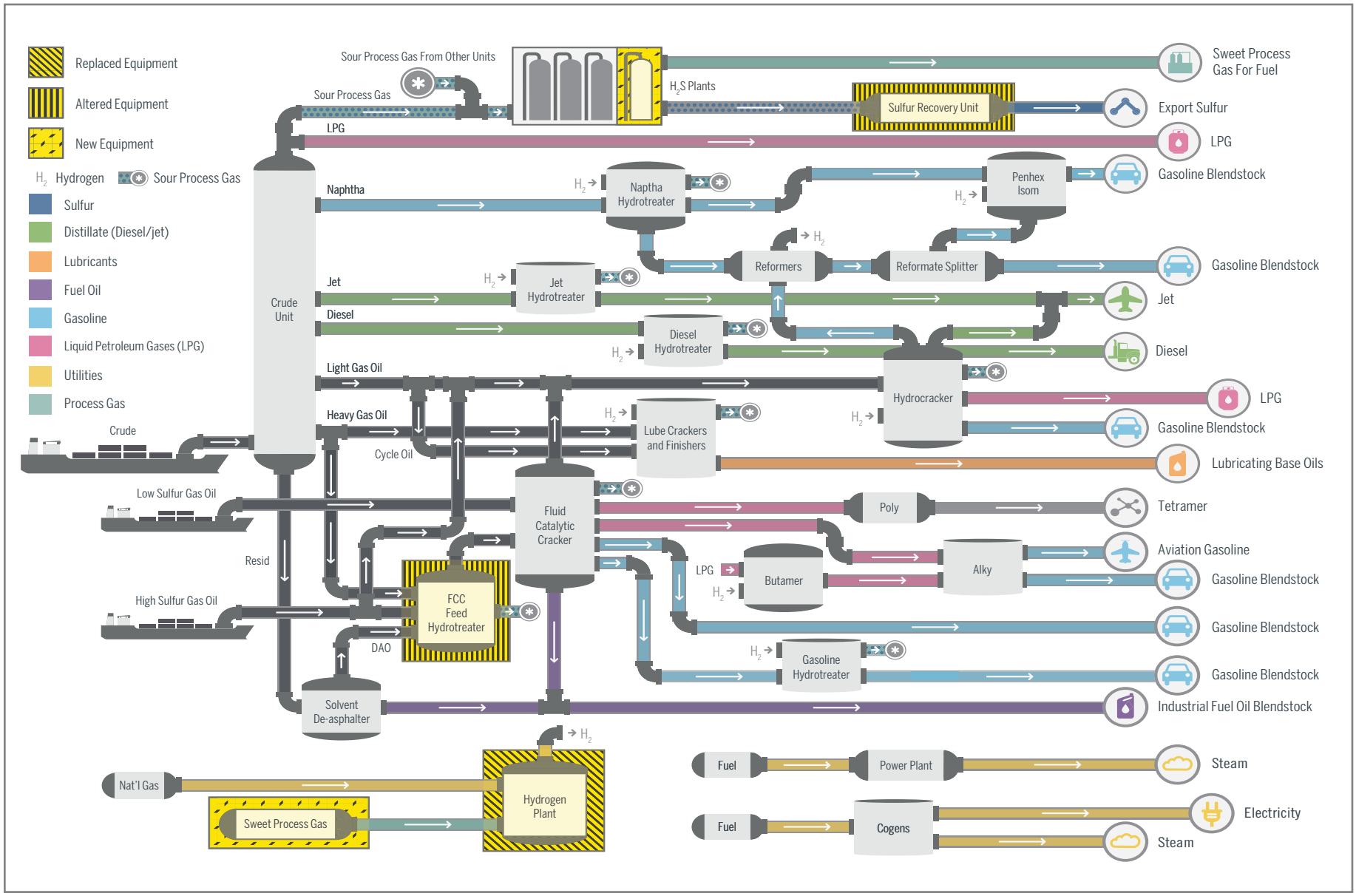
Table A4.3-URM-1 lists the Facility process units analyzed in the URM. Figure A4.3-URM-1 graphically depicts the relationship between the processing units analyzed in the URM.

TABLE A4.3-URM-1 FACILITY OPERATING UNITS INCLUDED IN THE URM

Crude Unit – Atmospheric Column	Polymerization Unit (Poly)
Crude Unit – Vacuum Column	Hydrocracker
Naphtha Hydrotreater (NHT)	Richmond Lube Oil Plant (RLOP)
Catalytic Reformers	LNC--light neutral hydrocracker
Pen/Hex Isomerization Unit (Pen/Hex)	LNF-light neutral hydrofinisher
Jet Hydrotreater (JHT)	HNC--heavy neutral hydrocracker
Diesel Hydrotreater (DHT)	HNF--heavy neutral hydrofinisher
Fluidized Catalytic Cracker Feed Hydrotreater (FCC FHT)	Solvent De-Asphalting (SDA) Unit
Fluid Catalytic Cracker (FCC) Unit	Sulfur Recovery Unit (SRU)
Gasoline Hydrotreater (GHT)	Hydrogen Plant
Alkylation Unit	

As shown in Figure A4.3-URM-1, gas oil obtained from the crude unit, and high- and low-sulfur gas oil purchased by and shipped to the Facility, is initially processed by one of five gas oil gateway units: the fluidized catalytic cracker feed hydrotreater (FCC FHT); the fluid catalytic cracker (FCC); the hydrocracker; and the light neutral hydrocracker (LNC) and heavy neutral hydrocracker (HNC) in

utilization rate was approximately 92.7% in 1998. To provide a conservative assessment, the EIR includes the analysis of 93% utilization cases to reflect the highest PADD V annual average refinery utilization rate reported by the EIA over 1985-2012.



02.28.2014 P:\11-005 CVRN\PRODUCTS\DEIR\Figures\Appx 4.3_AQ\AQ-URM Draft\CVRN Figure A4.3-URM-1

Source: Chevron (T39r2)

Figure A4.3-URM-1
Chevron Refinery Modernization Project EIR
General Facility Unit Flow Chart

the Richmond Lube Oil Plant (RLOP), which is a part of the Facility that produces lubricating oils. The percentage of total gas oil gateway unit permitted capacity that is utilized under future conditions is an input to the URM in each case. The model determines how much of the applicable gas oil gateway unit capacity will be supplied from the crude oil blend used by the Facility, and calculates how much additional gas oil must be purchased to achieve the specified utilization rate. In a 100% scenario, for example, the URM calculates the amount of gas oil the Facility would need to purchase, in addition to gas oil obtained from the applicable crude oil blend, to operate the gas oil gateway units at 100% of permitted capacity.

Several units, primarily the Facility hydrocrackers and hydrotreaters, use hydrogen to assist in the cracking process and remove sulfur in the form of hydrogen sulfide gas. These units are supplied with hydrogen produced by the Facility's catalytic reformers and the hydrogen plant, as well as hydrogen recovered from Facility process gas. The hydrogen sulfide gas created as a result of sulfur removal is separated from the hydrocarbon stream, conveyed to the sulfur recovery unit (SRU) and is recovered as elemental sulfur. The recovered sulfur is sold as "sulfur product" for agricultural and other uses.

The URM calculates SRU use rates under post-Modernization Project conditions as a function of the sulfur load into the refinery less the sulfur contained in the fuel oil blendstock that exits the Facility from the SDA. To provide a conservative assessment of emissions related to hydrogen production for extracting sulfur from various units, the URM assumes that all of the net sulfur load (crude blend sulfur minus the sulfur that exits the Facility as fuel oil blendstock from the SDA) to the Facility will be processed and recovered by the SRU, although very small amounts of sulfur exit the Facility as sulfur dioxide, due to the combustion of small amounts of sulfur in the Facility fuel gas, or in finished products. The heavy bottom discharge from the FCC unit also contains sulfur that is not further processed in the Facility or recovered by the SRU, but represents a small amount of the total sulfur input as well.

The URM was utilized to calculate Facility process unit throughput, sulfur recovery and hydrogen plant production levels under post-Modernization Project conditions using a representative selection of crude data to understand the effect of processing a range of heavier and lighter crude oil blends, higher or lower crude and gas oil sulfur contents, and greater or lower purchased crude and gas oil volumes. To provide a conservative assessment, while the crude blends analyzed in the "Modernization Project Related Cases" (see *Section 4.3.1.A*) are meant to be representative of crude blends that could be processed under post-Modernization Project operating conditions, the crude blends for these and other URM cases were generally considered without regard to feasibility due to factors such as accessibility, fractional properties that are

incompatible with the range of crudes that the Facility is designed to process, or chemical properties, such as excessive acidity that would damage certain Facility processing units (see *Chapter 4.13, Public Safety*).

As discussed below, the Modernization Project EIR focuses on eight representative cases derived from the URM, including: (a) four cases based on 100% crude and gas oil gateway unit capacity utilization (100% Utilization scenarios); and (b) four cases based on 93% crude and gas oil gateway unit capacity utilization (93% Utilization scenarios). This URM appendix also discusses (a) three cases that illustrate model results based on Facility use of extremely light, extremely heavy and very high sulfur content crude oil; (b) two no-Modernization Project cases considered in the alternatives sections of the EIR assuming the Facility operates at 93% and 100% of the crude and gas oil gateway unit capacity without Modernization Project changes and using the average daily crude oil blends and gas oils from the Baseline Period; and (c) two "limited sulfur capacity" cases considered in the alternatives sections of the EIR assuming the Facility operates at 93% and 100% of the crude and gas oil gateway unit capacity under post-Modernization Project conditions but with a lower SRU capacity of 750 long tons per day (lt/d). For informational purposes, several other URM analysis results that were considered during the preparation of the Modernization Project EIR are included in Attachment 3.

4.2 URM METHODOLOGY

This section discusses the principal URM analysis methods for evaluating the post-Modernization Project process unit throughput rates related to processing heavier or lighter crude oil, crude or gas oil with higher or lower sulfur contents and different crude and gas oil capacity utilization levels, including: (1) the approach used to develop the URM from Baseline Period operational data; and (2) the methodologies used to estimate the volume of crude and gas oil use, sulfur removal and production, and hydrogen demand and production by the Facility under post-Modernization Project conditions.

4.2.1 Unit Rate Model Development

As illustrated in Figure A4.3-URM-1, crude oil blends enter the Facility through the crude unit and are distilled by heating into various fractions. These fractions are then fed to other process units within the Facility. The amount of each fraction is determined by the crude oil feedstock blend that enters the crude unit. Crude and gas oil feedstocks also contain varying amounts of sulfur that must be processed and removed from the Facility's products. Sulfur removal requires the use of hydrogen gas produced by other Facility operations and the hydrogen plant. The URM was developed to analyze how crude blend feedstocks with different fractional characteristics, and crude and gas oil feedstocks with different sulfur contents, would affect each unit's throughput volume. The

results were utilized to calculate processing volume-related emissions considering a variety of potential future crude blend and gas oil use scenarios.

The URM was developed by using publicly available technical resources and historical, average daily Facility crude and gas oil use and process unit throughputs provided by the Modernization Project applicant for 2008-2010 (the "Baseline Period"), including the average crude oil blend fractional characteristics and the sulfur content of the Facility feedstocks. Table A4.3-URM-2 summarizes the fractional characteristics and sulfur content of the average crude oil blend and the sulfur content of the purchased gas oil (gas oil shipped to the refinery to supplement gas oil obtained from the crude oil feedstock) during the Baseline Period.

TABLE A4.3-URM-2 BASELINE PERIOD CRUDE OIL BLEND CHARACTERISTICS AND CRUDE AND GAS OIL SULFUR CONTENT

Fraction (Boiling Point, ºF)	Volume of Crude Supply (%)
Crude Oil Fractional Characteristics	
Butane and Lighter Fractions	2.21
Naphtha (55-290)	19.29
Kerosene (290-510)	22.12
Diesel (510-625)	11.16
Gas Oil (625-770)	12.99
Heavy Gas Oil (770-1020)	17.25
Residuum (1020+)	14.99
Weight and Sulfur Content	
Crude Oil API Gravity (degrees)	33.7
Crude Oil Specific Gravity	0.857
Crude Oil Sulfur Content (wt. %)	1.58%
Sour Gas Oil Sulfur Content (wt. %)	1.5%
Sweet Gas Oil Sulfur Content (wt. %)	0.3%

As shown in Table A4.3-URM-2, during the Baseline Period, the Facility generally processed crude oil blends with an average gravity in the light end of the intermediate range and with an average API gravity of approximately 33.7

degrees (°). The crude oil sulfur content by weight during the Baseline Period was approximately 1.58% by weight.[3] The Facility also purchased "sweet" gas oil with an approximate sulfur content by weight of 0.25% for FCC unit processing, and "sour" gas oil with an approximate sulfur content by weight of 1.5% for processing by other gas oil units (see Table A4.3-URM-1 for process unit acronym definitions).

The crude oil fractional characteristics, gravity[4] and sulfur content data summarized in Table A4.3-URM-2 are inputs required by the URM to complete the analysis of each case and are derived from applicable crude oil assay data. These and other URM inputs are listed in Attachment 1 and include: (1) the crude oil blend fractional characteristics (percent of each fraction in the crude oil blend); (2) the crude oil blend sulfur content by percent weight: (3) the crude oil blend specific gravity; (4) the amount of total crude oil sulfur contained in the residuum and processed in the SDA; and (5) gas oil sulfur content by percent weight. These inputs will vary with different crude oil blends and gas oils that may be purchased for the Facility. As discussed below, the URM also uses the specific gravity of gas oil as an input to calculate the amount of sulfur recovered by the SRU, but this value is assumed to be 0.91.[5]

Table A4.3-URM-3 summarizes the average daily volume of crude and gas oil and unit throughput rates for the Facility during the Baseline Period and compares these rates to the applicable unit annual average permit limit under Title V of the federal Clean Air Act. During the Baseline Period, the Facility used approximately 227,900 b/d of crude oil and approximately 45,400 b/d of gas oil, including 34,500 b/d of "sweet" gas oil. Total crude and gas oil inputs were approximately 273,300 b/d. On an average daily basis, none of the Facility units included in the URM operated at applicable permitted limits during the Baseline Period.

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[3] All references to sulfur content in this technical appendix are expressed in terms of percent sulfur by weight.

[4] The API and specific gravity of a crude oil are different methods for expressing the same measure of weight or crude oil gravity. For calculation purposes, the URM uses the applicable specific gravity. For ease of reference, crude oil weights are generally described in terms of °API in the text of this appendix.

[5] The Modernization Project applicant has indicated that the gas oil purchased typically ranges from 22-36 °API. A specific gravity of 0.91 (24 °API) is near the lower end (heavier) of the API range and therefore provides a conservative estimate of the gas oil specific gravity used in the Facility.

TABLE A4.3-URM-3 BASELINE PERIOD FACILITY AVERAGE DAILY OPERATIONS

Oil Source	Input Rate (b/d)	Existing (pre-Modernization Project) Annual Average Daily Limit (b/d)	Percent Existing Permit Limit Utilized
Crude and Gas Oil Inputs			
Crude Oil	227,900	257,200	88.6%
Sweet Gas Oil	34,500	N/A	
Sour Gas Oil	10,900	N/A	
TOTAL	**273,300**		

Operating Unit	Use Rate (b/d Except Where Noted)	Existing (pre-Modernization Project) Annual Average Daily Limit (b/d)	Percent Existing Permit Limit Utilized
Process Unit Throughput/Production Rates			
Crude Unit – Atmospheric Column	227,900	257,200	88.6%
Crude Unit – Vacuum Column[a]	89,900	N/A	
NHT	49,800	57,600	86.5%
Catalytic Reformers	45,500	68,700	66.2%
Pen/Hex Isomerization Unit	24,600	65,000	37.8%
Butane Isomerization (Butamer) Unit[b]		12,000	
JHT	61,100	96,000	63.6%
DHT	28,800	64,800	44.4%
FCC FHT	36,300	65,000	55.8%
FCC	70,500	80,000	88.1%
GHT	17,200	64,800	26.5%
Alkylation Unit	27,700	36,000	76.9%
Polymerization Unit	6,700	8,000	83.8%
Hydrocracker	45,000	51,300	87.7%
Richmond Lube Oil Plant (RLOP)			
LNC – light neutral hydrocracker	12,600	16,500	76.4%

TABLE A4.3-URM-3 BASELINE PERIOD FACILITY AVERAGE DAILY OPERATIONS

Oil Source	Input Rate (b/d)	Existing (pre-Modernization Project) Annual Average Daily Limit (b/d)	Percent Existing Permit Limit Utilized
LNF – light neutral hydrofinisher	15,400	22,000	70.0%
HNC – heavy neutral hydrocracker	20,600	26,000	79.2%
HNF – heavy neutral hydrofinisher	6,000	12,000	50.0%
Solvent De-Asphalting (SDA) Unit	33,900	56,000	67.8%
Sulfur Recovery Unit (SRU)(long tons/day)	398	600	66.3%
Hydrogen Plant production (mmscfd)	164	181.1[c]	90.6%

Note: b/d = barrels per day; mmscfd= million standard cubic feet per day.

[a] The Baseline Period throughput level for the crude unit - vacuum column is a URM model estimate based on the average crude oil blend assay data and total feed to the crude unit.

[b] The butane isomerization (butamer) unit does not have an associated furnace and does not generate combustion-related emissions. As discussed below, the unit has been included in the analysis of hydrogen demand and does not otherwise affect the URM. The butamer unit permit limit is included for informational purposes in Table A4.3-URM-4.

[c] The permit limit for the existing hydrogen plant is not adjusted for purity. Existing hydrogen plant production is approximately 94% hydrogen. As a result, the actual amount of hydrogen available for Facility use at the existing plant's full capacity is approximately 170.2 mmscfd.

Based on the Baseline Period data provided by the Modernization Project applicant and other technical sources, the URM allocates crude and gas oil feedstocks to the Facility process units using the parameters listed in Attachment 2. The URM also incorporates the increased throughput limits for the FCC FHT, the new hydrogen plant and the SRU, and the 50,000 b/d limit on the SDA throughput, that would result from the proposed Modernization Project. These throughput limit changes are listed in Table A4.3-URM-4.

4.2.2 Crude Unit Capacity Utilization

The Facility is permitted to process up to 257,200 b/d of crude oil and this limit would not be modified by the Modernization Project. The percentage of the crude unit's capacity that is used in each case is specified as an input to the URM (see Attachment 1). A 93% utilization scenario, for example, analyzes Facility unit throughput volumes that result from using 93% of the crude unit's permitted capacity, or approximately 239,200 b/d.

TABLE A4.3-URM-4 EXISTING AND POST-PROJECT UNIT THROUGHPUT PERMIT LIMITS (CHANGES IN BOLD)

Process Unit (b/d except where noted)	Existing Permit Limit	Post-Modernization Project Permit Limit	Post-Modernization Project Change
Crude Unit – Atmospheric Column	257,200	257,200	0
Crude Unit Vacuum Column[a]	n/a	n/a	n/a
NHT	57,600	57,600	0
Catalytic Reformers	68,700	68,700	0
Pen/Hex Unit	65,000	65,000	0
Butane Isomerization Unit (Butamer)	12,000	12,000	0
JHT	96,000	96,000	0
DHT	64,800	64,800	0
FCC FHT	65,000	80,000	**15,000**
FCC	80,000	80,000	0
GHT	64,800	64,800	0
Alkylation Unit	36,000	36,000	0
Polymerization Unit	8,000	8,000	0
Hydrocracker	51,300	51,300	0
Richmond Lube Oil Plant (RLOP)			
LNC--light neutral hydrocracker	16,500	16,500	0
LNF-light neutral hydrofinisher	22,000	22,000	0
HNC--heavy neutral hydrocracker	26,000	26,000	0
HNF--heavy neutral hydrofinisher	12,000	12,000	0
SDA Unit	56,000	50,000	**-6,000**
SRU Plant (lt/d)	600	900	**300**
Hydrogen Plant production (mmscfd)	181.1[b]	244	**63**

Note: b/d = barrels per day; mmscfd= million standard cubic feet per day; lt/d = long tons per day.

[a] The Crude Unit's vacuum column only receives feed directly from the crude unit's atmospheric column.

[b] The permit limit for the existing hydrogen plant is not adjusted for purity. Existing hydrogen plant production is approximately 94% hydrogen. As a result, the actual amount of hydrogen available for Facility use at the existing plant's full capacity is approximately 170.2 mmscfd.

The Facility's ability to process crude oil that is much heavier or lighter than the crude oil blend used during the Baseline Period is subject to two existing constraints that would not be affected by the Modernization Project: (1) the SDA throughput limit for heavier crude oils, and (2) the NHT throughput limit for lighter crude oils.

In general, heavier crude oil contains a proportionately larger share of heavier fractions, including the heaviest fraction, the residuum. The entire residuum fraction in the crude blend feedstock to the Facility is routed from the crude unit to the SDA unit for further processing. In the SDA unit, the residuum is separated into either de-asphalted oil (DAO), which is then routed to other Facility units, or fuel oil blendstock, which exits the Facility from the SDA. The SDA annual average throughput limit under existing permits is 56,000 b/d, but equipment limitations and other factors do not allow the unit to operate at more than an annual average throughput of 50,000 b/d. The Facility is not equipped with alternative process units or sufficient storage and treatment facilities to manage the residuum other than by routing this fraction to the SDA unit. The Modernization Project will not add any additional residuum processing or storage capacity to the Facility, and the Facility will commit to limiting SDA throughput by permit to 50,000 b/d on an annual average basis as a result of the Modernization Project. Consequently, under post-Modernization Project conditions, the Facility will be unable to process crude oil blends up to the permitted maximum of 257,200 b/d that contain more than 50,000 b/d of residuum on an annual average basis.

The Facility's ability to process much lighter crude blends than during the Baseline Period is constrained by the NHT throughput permit limit of 57,600 b/d. The NHT processes all of the naphtha fraction separated by the crude unit and receives additional feed from other Facility process units (see Attachment 2). The Facility is not equipped with alternative process units or sufficient storage and treatment facilities to process or store naphtha other than by routing these fractions to the NHT. The Modernization Project will not add any additional naphtha processing or storage capacity to the Facility, and the existing NHT throughput limit will not be modified by the Modernization Project. Consequently, under post-Modernization Project conditions, the Facility will be unable to process crude oil blends up to the permitted maximum of 257,200 b/d that, in combination with naphtha from other Facility units, would exceed 57,600 b/d of naphtha.

Table A4.3-URM-5 illustrates how the volume of heavier and lighter crudes could be constrained by the SDA and NHT unit throughput limits. Heavier crudes (e.g., Eocene crude with an approximate API of 18.3º) can contain more residuum than can be processed by the SDA at maximum crude rates. Eocene crude assay data, for example, indicates that 37.2% of the crude oil consists of residuum. The

Facility would be unable to process more than approximately 135,000 b/d of this crude oil blend without exceeding the SDA unit's 50,000 b/d limit.

Lighter crudes, (e.g., 100% Bakken crude with an approximate API of 41°) that contain a significantly higher amount of the naphtha fraction would, in combination with feeds routed from other Facility units, also be processed through the crude unit at a lower rate than the permitted limit. As illustrated in Table A4.3-URM-5, 100% Bakken crude assay data indicates that approximately 25% of the crude oil consists of the naphtha fraction. Feed from other Facility units also accounts for a portion of the NHT throughput. The Facility would be unable to process more than approximately 199,300 b/d of Bakken crude oil without exceeding the NHT unit's 57,600 b/d capacity.

In summary, to provide a conservative assessment, the URM is designed to use as much crude oil as possible up to the level of the crude unit's capacity utilization that is input to the model. The model can be iteratively run to identify crude oil blends that can be used by the Facility up to the 50,000 b/d SDA, the 57,600 b/d NHT, or any other unit's permit limit that might be exceeded before the specified level of crude unit capacity could be fully utilized.

4.2.3 Gas Oil Capacity Utilization

As discussed in *Chapter 4.0* of this EIR, gas oil is separated from crude oil by the crude unit and DOA is separated from the residuum by the SDA unit. There are no permit limits on the amount of gas oil that can be purchased for Facility use, and the total volume of gas oil utilization is limited by the capacity of the gas oil gateway units. Throughput limits for four gas oil gateway units—the FCC, the hydrocracker; the LNC and the HNC—would not be modified by the Modernization Project. The Modernization Project would increase the permitted throughput limit of the FCC FHT, the fifth gas oil gateway unit, by 15,000 b/d, which would increase the Facility's total gas oil processing capacity by approximately 1,200 b/d (see EIR *Chapter 3.0, Project Description, Section 3.3.2.1*). The URM accounts for the gas oil processing capacity increases that would result from the Modernization Project under future conditions.

The percentage of the gateway gas oil units' capacity that is used in each case is specified as an input to the URM (see Attachment 1). A 93% Utilization scenario, for example, analyzes Facility unit throughput volumes that result from using 93% of the crude unit and the gas oil gateway unit capacities. The amount of gas oil purchased for Facility use is calculated in the following manner:

1. Calculate the amount of gas oil required to operate the gas oil gateway units under post-Modernization Project conditions at the specified utilization level (e.g., 93%, 100% etc.);

TABLE A4.3-URM-5 ILLUSTRATION OF POTENTIAL CRUDE OIL USE CONSTRAINTS

Fraction Name and Boiling Point (ºF)	Percent of Crude Supply	Volume of Each Fraction (b/d, rounded to nearest 100)	Does the volume of a crude oil fraction result in a Facility feed that exceeds a processing unit throughput permit limit?
Baseline Period Crude Oil Blend (API = 33.7º)			
Butane and Lighter Fractions	2.21	5,700	NO
Naphtha (55-290)	19.29	49,600	NO
Kerosene (290-510)	22.12	56,900	NO
Diesel (510-625)	11.16	28,700	NO
Gas Oil (625-770)	12.99	33,400	NO
Heavy Gas Oil (770-1020)	17.25	44,400	NO
Residuum (1020+)	14.99	38,600	NO
Volume Crude Oil Use Without Exceeding a Processing Unit Throughput Limit		*257,200*	
Heavier Crude Oil (e.g., Eocene crude, API = 18.3º)			
Butane and Lighter Fractions	0.67	900	NO
Naphtha (55-290)	7.07	9,500	NO
Kerosene (290-510)	12.72	17,200	NO
Diesel (510-625)	9.24	12,500	NO
Gas Oil (625-770)	12.30	16,600	NO
Heavy Gas Oil (770-1020)	20.98	28,300	NO
Residuum (1020+)	37.02	50,000	**YES: SDA**
Volume Crude Oil Use Without Exceeding a Processing Unit Throughput Limit		*135,000*	
Light Crude Oil (e.g., 100% Bakken, API = 41º)			
Butane and Lighter Fractions	2.87	5,700	NO
Naphtha	25.20	50,200[a]	**YES: NHT[a]**
Kerosene (290-510)	26.54	52,900	NO
Diesel (510-625)	11.61	23,100	NO
Gas Oil (625-770)	11.82	23,600	NO

TABLE A4.3-URM-5 ILLUSTRATION OF POTENTIAL CRUDE OIL USE CONSTRAINTS

Fraction Name and Boiling Point (ºF)	Percent of Crude Supply	Volume of Each Fraction (b/d, rounded to nearest 100)	Does the volume of a crude oil fraction result in a Facility feed that exceeds a processing unit throughput permit limit?
Heavy Gas Oil (770-1020)	15.20	30,300	NO
Residuum (1020+)	6.77	13,500	NO
Volume Crude Oil Use Without Exceeding a Processing Unit Throughput Limit		*199,300*	

[a] The throughput total includes Facility feeds from other units as well as the naphtha fraction from the crude oil feedstock. If 100% Bakken crude with the fractional characteristics identified in Table A4.3-URM-5 was used by the Facility, the URM indicates that total NHT throughput from all feed sources would reach the 57,600 b/d NHT processing limit. The amount in the table is the naphtha feed from the crude unit alone not including feed from other Facility units.

2. Calculate the amount of gas oil supplied from crude oil based on the fractional characteristics of the crude oil blend used in the applicable scenario and the specified crude unit utilization (e.g., 93%, 100%, etc.);
3. Calculate the amount of gas oil that is an intermediate product of other internal Facility process units (e.g. hydrotreated gas oil from FCC FHT or DAO recovered from residuum by the SDA); and
4. Calculating the total maximum volume of purchased gas oil by subtracting (a) the amount of gas oil obtained from crude oil and from internal Facility processes from (b) the amount of gas oil required to operate the gas oil gateway units under post-Modernization Project conditions at the specified utilization level.

To provide a conservative assessment, the URM assumes that all of the purchased gas oil under post-Modernization Project conditions will consist of “sour” feedstock with higher sulfur content except for purchased gas oil routed directly to the FCC. To meet product sulfur content specifications, the FCC only processes low-sulfur, “sweet” gas oils. Based on the URM model parameters listed in Attachment 2, and to provide a conservative assessment of the amount of sulfur in purchased gas oil, the URM assumes that approximately 4,000 b/d of sweet gas oil will be purchased under post-Modernization Project conditions to operate both the FCC and the FCC FHT at full permitted capacity (the amount of sweet gas oil is scaled by the specified level of utilization in cases that assume

less than 100% utilization). In comparison, the Facility purchased approximately 34,500 b/d of sweet gas oil during the Baseline Period.

The method by which the URM calculates gas oil imports is illustrated in Table A4.3-URM-6 for a scenario that assumes 100% of the gas oil gateway unit capacity is utilized and that the crude oil feedstock has the same fractional characteristics as during the Baseline Period (see Table A4.3-URM-3). Approximately 253,800 b/d of gas oil would be required to operate the gas oil gateway units at full capacity. Approximately 77,800 b/d of gas oil would be obtained from the crude oil feedstock, and 110,800 b/d would be produced by other Facility processing units. Crude oil and internal Facility processing would therefore generate a gas oil supply of 188,600 b/d. As a result, approximately 65,200 b/d of gas oil would be purchased to operate the gas oil gateway units at full capacity (253,800-188,600 b/d). The amount of gas oil purchased under post-Modernization Project conditions varies with (a) the fractional characteristics of the crude oil feedstock, (b) the percentage of the crude unit's total capacity use, and (c) the percentage of total gas oil gateway unit capacity use that are entered as inputs to the URM (see Attachment 1).

4.2.4 Sulfur Content and SRU Analysis

The Modernization Project would increase the Facility's sulfur recovery or sulfur production limit from approximately 600 lt/d[6] to 900 lt/d. The crude and gas oil used in the Facility contains sulfur that must be removed during the refining process. The URM assumes that all sulfur entering the Facility in crude or gas oil will exit the Facility either in the fuel oil blendstock produced by the SDA unit, or as elemental sulfur recovered by the SRU. This methodology maximizes the energy required to treat and remove sulfur.

For crude oil, the URM estimates the total sulfur content (by weight) in the crude oil purchased for the Facility, and the weight of the sulfur that will exit the Facility in the fuel oil blendstock produced by the SDA. To determine the amount of sulfur in the fuel oil blendstock, the URM estimates the amount of total crude oil sulfur contained in the residuum fraction processed in the SDA. The residuum sulfur content varies with the characteristics of each crude oil purchased for the Facility. The ratio of the sulfur contained in the residuum to the total amount of sulfur in the crude oil sulfur is entered as an input to the URM based on applicable assay data for each case (see Attachment 1). In general, the residuum contains from 20% to 60% of the total sulfur in the crude oil feedstock.

[6] A long ton is 2,240 pounds.

TABLE A4.3-URM-6 GAS OIL DEMAND

	Barrels per Day
Gas Oil Gateway Unit Capacity at 100% Utilization	
FCC FHT	80,000
FCC	80,000
Hydrocracker	51,300
LNC	16,500
HNC	26,000
Total Gas Oil Gateway Unit Demand at 100% of Capacity	*253,800*
Gas Oil Supply from Crude and Refining	
Gas Oil from Crude Unit	(77,800)
DAO from SDA	(27,800)
Gas Oil Feed from FCC FHT to FCC	(73,600)
Gas oil from HNC	(2,400)
Gas Oil from FCC to Hydrocracker	(4,000)
Recycled Gas Oil from FCC to FCC FHT	(3,000)
Total Gas Oil from Crude Imports and Facility Processing	*(188,600)*
Gas Oil Import Volume	
TOTAL	**65,200**
Low Sulfur (Sweet) Gas Oil (for FCC Operation)	*4,000*
High Sulfur (Sour) Gas Oil	*61,200*

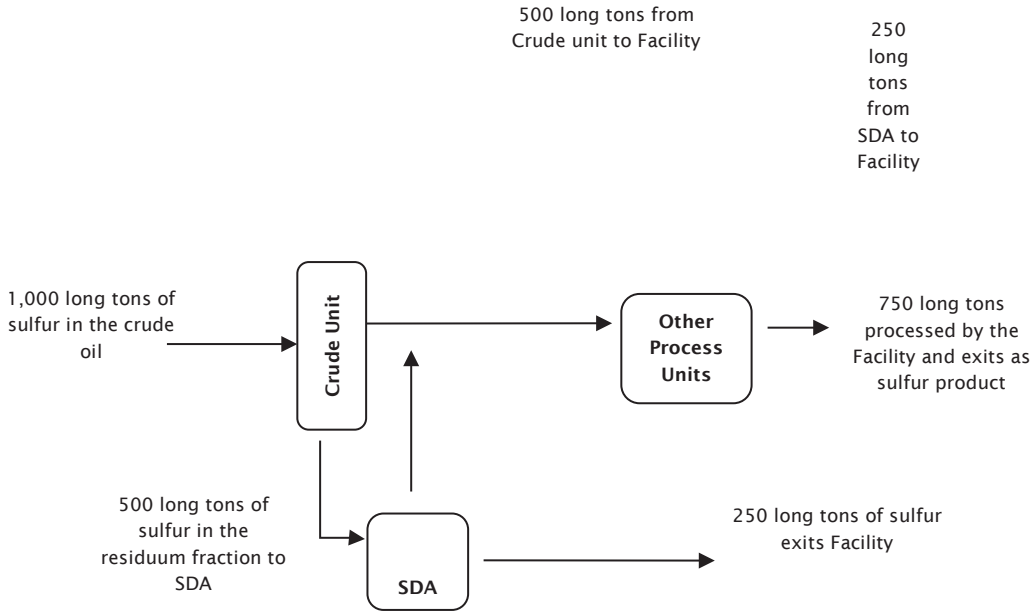
Note: Assuming (1) 100% gas oil unit and crude unit capacity use; and (2) crude oil with baseline period characteristics (see Table A4.3-URM-3) (barrels per day).

The URM then calculates the percentage of sulfur in the residuum that will exit the Facility in the fuel oil blendstock produced by the SDA and not further processed. Published information indicates that approximately 50% of the sulfur in the residuum will exit the Facility in the fuel oil blendstock,[7] and the URM utilizes this ratio assumption for all cases (see Attachment 2).

[7] Robert A Meyers, Handbook of Petroleum Refining Processes, Third Edition, (McGraw-Hill, 2004) p 10.27.

Figure A4.3-URM-2 illustrates the relationships between the crude unit, the SDA, and the rest of the Facility assuming that the crude oil feedstock contains 1000 long tons of sulfur and 50% of the total sulfur in the crude oil is contained in the residuum fraction. Under these assumptions, the URM calculates that 50% of the sulfur in the import crude oil (500 long tons) is contained in the fractions sent directly from the crude unit to other process units. The remaining 50% of the sulfur (500 long tons) is contained in the residuum and processed in the SDA. Half of the residuum sulfur content (250 long tons) will exit the refinery in the form of fuel oil blendstock produced by the SDA, and half (250 long tons) will be included in the gas oil produced by the SDA and sent to other Facility units for further processing. The total amount of sulfur processed by the Facility (not including the sulfur in the fuel oil blendstock) is 750 long tons. The URM assumes that all of the 750 long tons will be recovered by the SRU and will exit the Facility as elemental sulfur or sulfur product.

FIGURE A4.3-URM-2 ILLUSTRATION OF FACILITY SULFUR LOAD FROM CRUDE OIL FEEDSTOCK (1,000 LONG TONS OF SULFUR IN CRUDE OIL; 50% OF CRUDE OIL SULFUR IN RESIDUUM)



For gas oil, the URM assumes that all of the sulfur in purchased gas oil will be further processed within the Facility and exit as sulfur product from the SRU. The sulfur load attributable to purchased gas oil is calculated by estimating the total sulfur content by weight in sweet and sour gas oil based on the purchased volumes calculated by the URM.

Tables AQ-URM-7 and AQ-URM-8 illustrate the URM sulfur calculation methodology using model inputs that assume: (a) the crude oil feedstock has an API of approximately 31° and a sulfur content by weight of 2.75%; (b) purchased gas oil has a sulfur content by weight of 2.66%; (c) based on assay data, 19.44% of the crude oil feedstock consists of residuum and 55% of the total crude oil sulfur is contained in the residuum; and (d) the crude and gas oil gateway units are operated at 100% of capacity. As shown in Table A4.3-URM-7, the URM calculates that the Facility could process 257,200 b/d of crude oil, the permit maximum, without exceeding the NHT or the SDA throughput limits. In addition, approximately 57,000 b/d of purchased gas oil would be required to operate the gas oil gateway units at full capacity.

The total amount of sulfur introduced into the Facility is calculated using the crude and gas oil feedstock volumes, applicable crude and gas oil specific gravity data, and the percentage of sulfur by weight for each feedstock. Using this information, the URM calculates that the crude oil would contain approximately 962 lt/d of sulfur and that 55% of this amount (540 lt/d) will be routed to and processed in the SDA. The URM assumes that 50% of the sulfur processed in the SDA (265 lt/d) will exit the Facility in the fuel oil blendstock produced by the SDA without further processing.[8] The remaining half of the sulfur in the SDA (265 lt/d) will be routed to other Facility process units in the gas oil produced by the SDA. As shown in Table A4.3-URM-8, the total amount of sulfur from crude oil processed in the Facility will be 698 lt/d (962-265 lt/d).

The amount of sulfur in the purchased gas oil is calculated by using the gas oil specific gravity factor (0.91) assumed in the URM (see Attachment 1) and the percentage of sulfur by weight in sour and sweet gas oil purchased by the Facility. Based on this information, the URM calculates that the purchased sour gas oil will contain approximately 201 lt/d, and the purchased sweet gas oil will contain about 1 lt/d, or a total of 202 lt/d. The total sulfur processed in the Facility from both purchased import crude and gas oil, less the sulfur in the fuel oil blendstock produced by the SDA, would be 900 lt/d (698 + 202 lt/d). Under these conditions, the SRU would operate at its full post-Modernization Project

[8] From Robert A Meyers, Handbook of Petroleum Refining Processes, Third Edition, (McGraw-Hill, 2004) p 10.27.

TABLE A4.3-URM-7 ILLUSTRATION OF URM UNIT RATE CALCULATIONS

Unit	Unit Rate (b/d)
Crude Oil	257,200
Purchased Gas Oil	57,000
Sweet Gas Oil	*4,000*
Sour Gas Oil	*53,000*
Total	**314,200**

Process Unit	Throughput Rate (b/d)
Crude Unit – Atmospheric Column	257,200
Crude Unit – Vacuum Column	116,700
NHT	52,000
Catalytic Reformers	48,800
Pen/Hex Isomerization Unit	27,000
JHT	64,100
DHT	31,300
FCC FHT	80,000
FCC	80,000
GHT	19,500
Alkylation Unit	27,700
Polymerization Unit	7,600
Hydrocracker	51,300
Richmond Lube Oil Plant (RLOP)	
LNC – light neutral hydrocracker	16,500
LNF – light neutral hydrofinisher	22,000
HNC – heavy neutral hydrocracker	26,000
HNF – heavy neutral hydrofinisher	12,000
Solvent De-Asphalting (SDA) Unit	50,000

Notes: Except where noted; numbers are rounded to nearest 100.
Crude oil feedstock API = 31° and consists of 19.44% residuum. Crude and gas oil gateway units operating at 100% of capacity.
Table A4.3-URM-7 is based on Basrah/Arab Light crude blend.

TABLE A4.3-URM-8 ILLUSTRATION OF URM SULFUR CONTENT AND SRU ANALYSIS CRUDE AND GAS OIL GATEWAY UNITS OPERATING AT 100% OF CAPACITY

Crude Oil Sulfur Load	
Crude Oil Density, API Gravity	31.0
Crude Oil Specific Gravity	0.826
Crude Oil Sulfur Content by Weight	2.75%
Crude Oil Volume (b/d)	257,200
Total Sulfur in Crude (lt/day)	**962**
Sulfur Exiting Facility in Fuel Oil Blendstock from SDA (lt/day)	(265)
Percent Total Crude Sulfur by Weight in Residuum Processed in SDA	*55%*
Percent Sulfur Load Exiting Facility in Fuel Oil Blendstock from SDA	*50%*
Net Sulfur in Crude Oil Entering Facility excluding SDA Discharge (lt/day)	**698**
Gas Oil Sulfur Load	
Gas Oil (sweet and sour) Specific Gravity	0.91
"Sweet" Gas Oil Sulfur Content by Weight	0.25%
"Sweet" Gas Oil Volume (b/d)	4,000
"Sour" Gas Oil Sulfur Content by Weight	2.66%
"Sour" Gas Oil Volume (b/d)	53,000
Long tons per day Sulfur in Gas Oil	***202***
Total Sulfur in "Sweet" Gas Oil (lt/day)	*1*
Total Sulfur in "Sour" Gas Oil (lt/day)	*201*
Total Sulfur Processed by SRU in Facility (lt/day)	**900**

capacity and recover 900 lt/d from the Facility process units. The amount of sulfur the Facility processes varies with differences in the sulfur content, feedstock volumes, crude oil specific gravity, and the percentage of total crude oil sulfur contained in the residuum fraction for each case.

4.2.5 Post-Modernization Project Hydrogen Plant Production Calculation Methodology

Hydrogen is used within Facility process units for (a) the removal of sulfur and other naturally occurring impurities, and (b) “cracking” or otherwise changing crude oil fractions. As shown in Figure A4.3-URM-1, hydrogen is supplied to

several units and is produced by the Facility during the catalytic reforming process. Hydrogen is also recovered from various process gas streams and produced by the hydrogen plant for Facility use. Table A4.3-URM-9 lists the Facility process units that use hydrogen, and the hydrogen producing and recovery Facility activities analyzed in the URM.

The URM calculates post-Modernization Project hydrogen plant production for Facility use by subtracting the amount of hydrogen obtained from the Facility's catalytic reformers and process gas recovery from the total Facility hydrogen demand. Total Facility hydrogen demand is calculated by: (a) calculating per-barrel hydrogen demand for each hydrogen-using process unit, assuming crude and purchased sour gas oil has the same sulfur content as during the Baseline Period; and (b) adjusting the hydrogen demand as necessary to reflect increases or decreases from Baseline Period crude and purchased sour gas oil sulfur levels. The amount of hydrogen supplied by the production plant for Facility use is the difference between total Facility hydrogen demand adjusted for applicable sulfur content levels, and the amount of hydrogen available from other Facility operations.

Table A4.3-URM-10 illustrates the URM hydrogen plant production calculation methodology using the same model inputs in Tables AQ-URM-7 and AQ-URM-8, including a crude oil feedstock sulfur content of 2.75% and a purchased sour gas oil sulfur content of 2.66%. A per-barrel hydrogen demand factor for each of the Facility process units that use hydrogen was derived technical sources and Baseline Period operational data and integrated into the URM. Under Baseline Period conditions, for example, the NHT was estimated to use approximately 95 standard cubic feet (scf) of hydrogen per barrel and approximately 5.3 million scf per day (mmscfd) of hydrogen at a daily throughput of 56,200 b/d. The hydrocracker was estimated to use approximately 2,150 scf of hydrogen per barrel and approximately 110.3 mmscfd at a daily throughput of 51,300 b/d (see Attachment 2 for the hydrogen demand factors estimated for applicable units in the URM).

The URM adjusts the Facility's hydrogen demand by calculating the difference between the percentage of sulfur by weight in the crude oil (net of the sulfur that exits the Facility in the SDA fuel oil blendstock) and purchased gas oil compared with Baseline Period levels. If the sour gas oil content in a certain case is 2.5%, for example, the difference between the Baseline Period gas oil sulfur content level of 1.5% is +1.0%. Based on available technical information, approximately 100 scf per barrel per day is required to change the sulfur content of a barrel of

TABLE A4.3-URM-9 LIST OF FACILITY UNITS THAT USE OR PRODUCE HYDROGEN

Refinery Units that Use Hydrogen	Refinery Operations that Produce or Recover Hydrogen
NHT	Catalytic Reformers[a]
JHT	Hydrogen Recovery from Process Gas
DHT	Hydrogen Plant – Hydrogen Production
FCC FHT	
Hydrocracker	
GHT	
Pen/Hex Isomerization Unit	
Richmond Lube Oil Plant (RLOP)	
LNC – light neutral hydrocracker	
LNF – light neutral hydrofinisher	
HNC – heavy neutral hydrocracker	
HNF – heavy neutral hydrofinisher	
Butamer Unit	

[a] The catalytic reformers use and produce hydrogen and are a net hydrogen producer. As a result, these units are included in the list of refinery operations that produce or recover hydrogen.

TABLE A4.3-URM-10 ILLUSTRATION OF URM HYDROGEN DEMAND ANALYSIS

	Barrels per Day[a]	Demand or Production (scf per Barrel)	Total H2 Demand or Production (mmscfd)
Hydrogen Demand			
NHT	52,000	95	4.9
JHT	64,000	145	9.3
DHT	31,300	425	13.3
FCC FHT	80,000	-	
Purchased gas oil+ vacuum gas oil	*41,000*	*630*	*25.8*
SDA-Produced DAO + recycled gas oil	*39,000*	*950*	*37.1*
Hydrocracker	51,300	2,150	110.3

TABLE A4.3-URM-10 ILLUSTRATION OF URM HYDROGEN DEMAND ANALYSIS

	Barrels per Day[a]	Demand or Production (scf per Barrel)	Total H2 Demand or Production (mmscfd)
GHT	19,500	60	1.2
Pen/Hex Isomerization and Benzene Saturation Unit	27,000	295	8.0
Richmond Lube Oil Plant (RLOP)			
LNC – light neutral hydrocracker	16,500	1,100	18.2
LNF – light neutral hydrofinisher	22,000	150	3.3
HNC – heavy neutral hydrocracker	26,000	1,100	28.6
HNF – heavy neutral hydrofinisher	12,000	250	3.0
Butamer Unit Use[b]		0.30	0.3
Sulfur Adjustment (100 SCF/Barrel per percent change from Baseline Period Sulfur Content)[c]			
Crude Oil Sulfur Content Adjustment (mmscfd)			*21.6*
Gas Oil Sulfur Content Adjustment (mmscfd)			*6.1*
Total Facility Hydrogen Demand			**291.0**
Hydrogen Supply From Refinery Operations			
Hydrogen Produced by the Catalytic Reformers	48,800	850	(41.5)
Hydrogen Recovered from Process Gas/Percent Recovery	34.18	90%	(30.8)
Total Hydrogen Supply from Operations			**(72.3)**
Total Hydrogen Plant Production for Facility Use			**218.8**

[a] See Table 7, rounded to nearest 100.
[b] The URM assumes that the butamer unit will have constant demand of 0.3 mmscfd.
[c] Adjustment factors from M.D. Edgar, et. al. 1984.

oil by 1% (M.D.Edgar, et. al., 1984).[9] As a result, the URM assumes that processing gas oil with a sulfur content of 2.5% would require 100 scf per barrel more hydrogen than gas oil with a Baseline Period sulfur content of 1.5%.

[9] The adjustment factor is consistent with estimates of theoretical hydrogen usage, that show the that the amount of hydrogen required to remove one incremental percent

Table A4.3-URM-11 illustrates the URM hydrogen demand adjustment summarized in Table A4.3-URM-10 in more detail. Excluding the sulfur exiting the Facility from the SDA, the sulfur content in the Baseline Period crude oil blend was 1.26% by weight. The sulfur content in the crude oil analyzed in Table A4.3-URM-11 is 2.15% excluding the sulfur exiting the Facility from the SDA, an increase of 0.89% from Baseline Period levels. Based on this differential, the URM increases total Facility hydrogen demand by 21.6 mmscfd given a total import crude volume of 238,714 b/d to the Facility excluding the volume of fuel oil blendstock discharged from the SDA. The sulfur content in Baseline Period sour gas oil was 1.5% compared to the value of 2.66% assumed in AQ-URM-Table 11. Based on this differential, the URM increases total Facility hydrogen demand by 6.1 mmscfd utilizing the calculated purchased sour gas oil volume of 53,000 b/d (see Table A4.3-URM-8).

Including these adjustments, the URM calculates that the total Facility hydrogen demand will be 291 mmscfd (see Table A4.3-URM-10).

The URM solves for the amount of hydrogen that the hydrogen plant supplies to the Facility by comparing total demand to internally-generated Facility hydrogen supplies. The Facility produces hydrogen from two internal sources: (a) the catalytic reformers at an assumed post-Modernization Project rate of approximately 850 scf per barrel of throughput; and (b) hydrogen recovered from process gas in the pressure swing absorption unit. Based on information supplied by the Modernization Project applicant, the hydrogen content available for recovery from process gas using Baseline Period crude and gas oil is approximately 30 mmscfd. The URM also assumes 90% of the fuel gas hydrogen will be recovered under post-Modernization Project conditions for use in the Facility.[10] Under the assumptions used in Tables AQ-URM-7 to AQ-URM-11, the

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of sulfur per barrel would be 34-40 scf. This range was calculated via the following equation:

$$H = SG_{crude} \times \rho_{water} \times 42\frac{gallons}{barrel} \times 1\%S \times \frac{1\ lb-mol}{32.07\ lb\ S} \times \frac{1\ lb-mol\ S}{1\ lb-mol\ H_2} \times \frac{1\ scf}{0.0026412\ lb-mol}$$

Where:

H = scf H_2/barrel/%Sulfur

SG_{crude} = Specific Gravity (ratio of a material's density to that of water) of crude oil; ranges from 0.8203-0.97 for crudes considered in this EIR (unitless)

ρ_{water} = density of water (8.3 lbs/gallon)

This assumes that it would take exactly one mole of hydrogen to remove one mole of sulfur. However, the hydrogen gas can be consumed in other chemical reactions, or simply may not react at all, requiring a greater amount of hydrogen than under ideal calculations.

[10] The URM estimates the fuel gas hydrogen content by multiplying the per unit hydrogen demand prior to adjustment by 13%. This produces 30 mmscfd under post-

TABLE A4.3-URM-11 ILLUSTRATION OF FACILITY HYDROGEN DEMAND ADJUSTMENT

Crude Oil Hydrogen Demand Adjustment	
Sulfur in Crude Oil Excluding Fuel Oil Blendstock Produced by the SDA	2.15%
Baseline Period Sulfur in Crude Oil Net of SDA Fuel Oil Blendstock	1.26%
Difference from Baseline Period	0.89%
Hydrogen Demand Per Barrel Per Percent Sulfur Content by Weight (SCF)	100
Crude Oil Excluding the Fuel Oil Blendstock Produced by the SDA (b/d)	238,714
Crude Oil Sulfur Content Adjustment (mmscfd)	**21.6**
Gas Oil Hydrogen Demand Adjustment	
Sulfur in Sour Gas Oil	2.66%
Baseline Period Sour Gas Oil Sulfur Content	1.50%
Difference from Baseline Period	1.16%
Hydrogen Demand Per Barrel Per Percent Sulfur Content by Weight (SCF)	100
Sour Gas Oil (b/d)	53,000
Gas Oil Sulfur Content Adjustment (mmscfd)	**6.1**

reformers and process gas recovery process would generate 72.2 mmscfd of hydrogen for Facility use compared with a Facility demand of 291 mmscfd. The URM calculates the difference between the available internal Facility hydrogen supply and total Facility demand, or 218.8 mmscf (291-72.2 mmscf) and assumes that all of the difference in demand will be met by hydrogen supplied from the hydrogen plant. The total amount of hydrogen used in the Facility, and the hydrogen plant's level of production, will vary with the level of crude and gas oil sulfur content, crude and purchased gas oil feedstock volumes, the amount of sulfur in the fuel oil blendstock produced by the SDA that exits the Facility, and crude oil specific gravity applicable to each case.

Modernization Project, maximum use conditions assuming crude and purchased gas oil with the same characteristics as during the Baseline Period. The available hydrogen in fuel gas will vary with calculated unit throughputs and is scaled in all cases by the 13% factor derived from Baseline period data. As shown in Table 9, when applicable unit throughput rates are higher than the results obtained from using Baseline Period crude and gas oil, the amount of hydrogen recovered from fuel gas can be slightly higher (i.e., 34.18 mmscf) than 30 mmscf.

4.2.6 2011 Facility Data and URM Analysis Results

This section compares the URM gas oil purchase, unit rate, and sulfur and hydrogen production calculations with actual refinery operations in 2011. The Notice of Preparation for the Modernization Project was issued in 2011, and the prior 3 years of operational information was used to evaluate the Facility's existing annualized operations. After the URM was developed, one more year of annualized operational data became available for 2011.[11] The actual 2011 Facility operating data was compared with model calculations using 2011 inputs to evaluate the accuracy of the URM. As discussed above, the URM requires certain inputs to calculate unit rates, sulfur recovery by the SRU, hydrogen demand and total crude and purchased gas oil use. Table A4.3-URM-12 summarizes the URM crude oil inputs from 2011 operational data provided by the Modernization Project applicant.

TABLE A4.3-URM-12 2011 CRUDE OIL VOLUME, WEIGHT AND FRACTIONAL DATA INPUT TO THE URM

Crude Oil Utilization (b/d)	195,600
Crude Oil API Gravity (degrees)	34
Specific Gravity	0.855
Fraction (Boiling Point, ºF)	**Percent of Total Crude Oil**
Butane and Lighter Fractions	2.09
Naphtha (55-290)	19.11
Kerosene (290-510)	22.46
Diesel (510-625)	11.30
Gas Oil (625-770)	13.17
Heavy Oil (770-1020)	17.37
Residuum (1020+)	14.51

The refinery utilized approximately 195,600 b/d of crude oil during 2011 with gravity of approximately 34º API. The fractional characteristics of the 2011 crude oil feedstock were estimated on the basis of applicable assay data.

[11] The Facility crude unit was not operated for portions of 2012 and 2013 due to a fire in August 2012. As a result, 2012 and 2013 do not reflect the Facility's typical annualized operations.

Table A4.3-URM-13 summarizes the sulfur content inputs for 2011 entered into the URM.

TABLE A4.3-URM-13 2011 SULFUR CONTENT DATA INPUT TO THE URM

Crude Oil Sulfur Content	1.50%
Sour Gas Oil Sulfur Content	1.50%
Sweet Gas Oil Sulfur Content	0.25%
Crude Oil Sulfur in Residuum Fraction Processed in SDA	50%

Based on crude oil blend summaries provided by the Modernization Project applicant, the sulfur content of the crude oil was estimated to be approximately 1.50% by weight in 2011. The sulfur content in 2011 gas oil purchased by the Facility was estimated on the basis of consultations with the Modernization Project applicant and was approximately 0.25% by weight for sweet gas oil and approximately 1.50% by weight for sour gas oil. Based on assay data, approximately 50% of the crude oil sulfur content was contained in the residuum processed by the SDA during 2011, approximately the same ratio as the Baseline Period.

Table A4.3-URM-14 summarizes the gas oil gateway unit utilization rates for 2011 that were input to the URM.

TABLE A4.3-URM-14 2011 GAS OIL GATEWAY UNIT THROUGHPUT DATA INPUT TO THE URM

Gas Oil Gateway Unit	2011 Utilization (b/d)	Percent of 2011 Permitted Capacity
FCC FHT	33,800	52%
Hydrocracker	44,500	87%
FCC	70,400	88%
RLOP Hydrocrackers		
LNC – light neutral hydrocracker	10,200	62%
HNC – heavy neutral hydrocracker	18,800	72%

Note: Totals rounded to nearest 100.

The percentage of available capacity for the five gas oil gateway units varied from 52% for the FCC FHT to 88% for the FCC. Based on information provided by the Modernization Project applicant, the Facility purchased approximated 48,000 b/d of gas oil, including 38,000 b/d of sweet and 10,000 b/d of sour gas oil.

The URM was used to calculate unit rates, sulfur recovery and hydrogen demand, and purchased gas oil for the Facility based on the 2011 inputs summarized in Tables AQ-URM-12 to AQ-URM-14. The analysis results are presented in Table A4.3-URM-15 and compared with the operational data for 2011. The shaded rows identify the six units (the crude unit and the five gas oil gateway units) that function as URM inputs. The unshaded rows are units or other refinery operational results that are calculated by the URM.

As shown in Table A4.3-URM-15, in almost all instances the URM results are higher, and therefore more conservative, than the 2011 data for each unit and Facility activity calculated by the model. The Facility's gas oil purchases, sulfur recovery, and hydrogen plant demand were all lower in 2011 than calculated by the URM. The average daily throughput in the crude unit vacuum column, NHT, catalytic reformers, pen/hex isomerization unit, JHT and DHT was also lower during the year than calculated by the URM. The model results were lower for only three units, including the GHT and the small polymerization unit which has negligible effect on total refinery activity. Model results were also approximately 2% lower for the SDA and within the range of assay data variability that can occur over a year. The URM sulfur recovery and hydrogen demand calculations were within 0.86% and 1.16% of the 2011 operational results. As a result, the URM provides a more conservative analysis of 2011 Facility activity compared with operational data for that year.

4.3 SUMMARY OF URM SCENARIOS

This section summarizes the URM scenarios that have been developed during the preparation of the Modernization Project EIR, including:

1. Eight scenarios that are representative of crude oil blends and gas oil that could be processed by the Facility under post-Project conditions assuming that proposed Modernization Project improvements have been completed and conservative 93% and 100% of crude and gas oil gateway unit capacity utilization rates;
2. Three scenarios that analyze potential Facility operations under future conditions assuming the proposed improvements have been completed, the use of crude oil that is much heavier, much lighter and that has a higher sulfur content than Baseline Period and the Modernization Project-related cases above;

TABLE A4.3-URM-15 URM RESULTS AND 2011 FACILITY DATA

	URM Results (b/d)	2011 Unit Rates (b/d)	2011 Unit Rate vs. URM Results (%)
Crude Oil	195,600	195,600	NA
Gas Oil	58,100	48,000	-21.04%
Total	**253,700**	**243,600**	**-4.15%**
Process Unit Throughput			
Crude Unit – Atmospheric Column	195,600	195,600	NA
NHT	42,200	38,300	-10.18%
Catalytic Reformers	40,400	38,400	-5.21%
Pen/Hex Isomerization Unit	22,100	21,900	-0.91%
JHT	52,300	50,900	-2.75%
DHT	26,500	25,700	-3.11%
FCC FHT	33,800	33,800	NA
FCC	70,400	70,400	NA
GHT	17,200	18,500	7.03%
Polymerization Unit	6,700	7,000	4.29%
Hydrocracker	44,500	44,500	NA
Richmond Lube Oil Plant (RLOP)			
LNC – light neutral hydrocracker	10,200	10,200	NA
HNC – heavy neutral hydrocracker	18,800	18,800	NA
Solvent De-Asphalting (SDA) Unit	28,400	29,000	2.07%
Sulfur Recovery Unit (SRU) (lt/day)	**351**	**348**	-0.86%
Hydrogen Plant Demand (mmscfd)	**148**	**146.3**	-1.16%

Note: Numbers rounded to nearest 100.

3. Two scenarios that analyze potential Facility operations under no-Modernization Project future conditions (i.e., no changes to the Facility related to the Modernization Project occur) assuming 93% and 100% of the crude and gas oil gateway unit capacity is utilized; and
4. Additional scenarios provided for informational purposes in Attachment 3 that analyze various crude oil blends that are highly unlikely or technically