Combustion Emissions from Refining Lower Quality Oil

Part 2: How Much Could a Switch to 'Tar Sands' Oil Increase Direct Emissions of $PM_{2.5}$ and CO_2 from Northern California Refineries?

Greg Karras, Senior Scientist,
Communities for a Better Environment (CBE)

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Abstract

Emissions from refining lower quality oil were estimated in the San Francisco Bay Area, where the second largest refining center in western North America is replacing declining current oil supplies with oil imports, and refinery emission limits are now proposed. Data for refinery crude feed, processing, yield, fuels, crude availability and cost, infrastructure plans and projects, and emissions were analyzed to identify a range of plausible worst-case refinery crude feed, energy consumption, and emissions scenarios. The quality of the regional crude feed could worsen from 2020–2050 as 50–80 percent of it is replaced with blends of heavy oil and bitumen. A peer reviewed method that predicted oil quality effects on Bay Area refining energy and emission intensities within 5 percent of those observed during 2008 and 2014 estimated emissions in these "tar sands" oil scenarios. Estimated refinery CO_2 and $PM_{2.5}$ emission intensities increased by ≈ 39–100 percent in these scenarios, increasing regional mass emissions from refineries by ≈ 5.9–16 million metric tons per year of CO_2 and ≈ 390–990 metric tons per year of $PM_{2.5}$.

Introduction

The San Francisco Bay Area hosts the second largest oil refining center in western North America after Los Angeles.[1] Chevron, Phillips 66, Shell, Tesoro, and Valero currently operate the five major refineries here. Collectively, Bay Area refiners produce gasoline and diesel in excess of northern California demand, dominate statewide exports of these fuels even after supplying some of the demand in southern California and other western states,[2] and emit more fine particulate matter and greenhouse gases than any other industrial sector in the Bay Area.[3]

Processing lower quality crude oil is known to increase refinery pollution rates,[4–22] and Bay Area refiners are known to be switching crude feeds as their current crude supply sources in California and Alaska decline.[26–29] Analysis of resource availability and climate constraints indicates that it is feasible, and more economic for society, to avoid low quality, high-emitting oils.[30] However, crude can account for up to 90 percent of a refiner's operating costs,[7] price discounts on low quality oils can exceed 18 percent,[31–34] and Bay Area refiners have announced plans to refine low quality oil[35–44] and have proposed infrastructure projects that could enable those plans.[45–59]

On 14 October 2016 the Bay Area Air Quality Management District (BAAQMD) proposed new Rule 12-16 and requested public comment on the scope of environmental review for this proposal. Proposed Rule 12-16 would establish limits on facility-level emissions of particulate matter air pollution ($PM_{2.5}$, PM_{10}, NO_x, and SO_2) and greenhouse gases (CO_2e) from oil refining in the Bay Area, set at levels that would prevent any significant increase in current annual emissions of these air pollutants.

A complete and accurate environmental review of this proposal to prevent increases in these emissions must, among other things, describe the potential increases in these emissions that the proposal, if implemented, would prevent. Thus, questions regarding whether potential crude feed quality-driven increases in these emissions can be estimated based on currently available information, and how much these emissions could increase in the plausible worst-case scenario, fall within the scope of this environmental review. This report addresses these questions.

Summary of Site-specific Oil Feed Quality Impacts Observed

Impacts of crude feed switching on Bay Area refinery feedstock contamination and pollution rates have been observed many times over more than twenty years.

In 1994 CBE showed that increased selenium (Se) discharges into the San Francisco Bay-Delta estuary were linked to denser, higher-selenium crude feeds.[4] In perhaps the first documented case of Bay Area refinery pollution violations linked to lower quality oil, Se discharges from the Rodeo, Martinez, and Benicia refineries exceeded their discharge limits. Se was concentrated in denser components of their crude feeds, released into the sour gas and sour water streams from coking and hydroprocessing, and passed through partial waste water treatment to discharge, on a mass per barrel refined basis, at rates reaching ten times those of other plants running lower-Se crude feeds.[4] When differences in waste water treatment were accounted for, the Se content of Bay Area refinery crude feeds predicted the refiners' Se/barrel discharge rates almost perfectly (R^2, 0.99).[4]

In 1999 a switch to lower quality, denser crude was a contributing factor in a catastrophic fire during crude unit maintenance work that killed workers and caused a massive air pollution plume at the Avon refinery near Martinez.[5] A U.S. Chemical Safety Board investigation of the incident found that the denser crude overwhelmed a crude desalting unit, resulting in corrosion product plugging of a crude unit pipe downstream which was undetected until the plug released during maintenance, fueling the catastrophic fire.[5]

In the mid-1990s Chevron expanded the capacity of the fluid catalytic cracking (FCC) unit at its Richmond refinery, increasing the refinery's capacity to process separately delivered heavy gas oil as a larger portion of its total oil feedstock. In 2011 the refiner used this capacity to process a total oil feed that, although lower in total crude-plus-gas oil volume, was proportionately higher in heavy gas oil than it processed in 2008.[6] Making gasoline and other engine fuels from heavy gas oil, the densest and most contaminated fraction of whole crude that distills in atmospheric and vacuum crude distillation, requires more energy-intensive carbon rejection and hydrogen addition processing than making the fuels from lighter crude fractions. Thus, refining proportionately more heavy gas oil would have increased the Richmond refinery's energy intensity, and consequently its CO_2 emission intensity, in 2011 as compared with 2008.[6] Reported data confirmed this expected emission intensity effect. The refiner's emission intensity (kg CO_2e/m^3 oil processed) increased in 2011, as compared with 2008.[6]

On 15 January 2007 a major fire in the Chevron Richmond refinery crude unit caused an air pollution plume over parts of Richmond and Marin County. Sulfidic corrosion, a damage mechanism in steel equipment that processes sulfur-containing oils at high temperatures, led to the crude unit pipe failure in this incident.[7] A subsequent incident investigation found that a switch to higher-sulfur crude, which had accelerated sulfidic corrosion,[7] was a contributing factor in the refiner's corrosion-incident emissions.

An April 2007 analysis of the causes of flare emissions at Bay Area refineries showed that refining denser and higher-sulfur crude feeds contributed to recurrent flare emission incidents caused by conversion-product gas imbalances at the refineries.[8]

In 2008 the Western States Petroleum Association (WSPA) reported that the total crude feed for Bay Area refineries contained an average mercury (Hg) content of ≈ 5.07 µg/kg.[9] This analysis was required by the Regional Water Quality Control Board after a U.S. EPA study[10] noted that exceptionally high-Hg crude streams from one source area supplying Bay Area refineries could be expected to result in elevated Hg emissions from refineries processing those streams. The WSPA report did not fully account for the disposition and fate of the Hg in these oils, however, it did show an impact. As compared with the weighted average Hg content of the nationwide refinery crude feed (2.9–4.1 µg/kg),[10] the higher Hg content WSPA reported (5.07 µg/kg)[9] documented elevated mercury levels in Bay Area refinery crude feeds.

In 2009–2010 the Phillips 66 San Francisco Refinery commissioned a new heavy gas oil hydrocracker and, with Air Liquide, a new fossil fuel fed hydrogen steam reforming plant that replaced a smaller hydrogen plant the refiner decommissioned at its Rodeo facility. The new hydrocracker increased the refiner's capacity to process lower quality, denser oil and the expanded steam reforming, an energy-intensive process that produces more CO_2 than hydrogen by mass, enabled that added hydrocracking by supplying more hydrogen. The use of this new infrastructure for refining lower quality oil increased the refiner's total CO_2e emissions substantially from pre-project (2008–2009) levels.[6]

In August 2012 twenty refinery workers narrowly escaped death and some 15,000 people sought emergency medical attention for pollution-related symptoms after a catastrophic pipe failure in the Chevron Richmond refinery crude unit spewed hot hydrocarbons that ignited in a major fire and air pollution incident.[7] Sulfidic corrosion that was accelerated by a switch to higher sulfur crude led to the catastrophic pipe failure. In the years before this incident Chevron switched the refinery's crude feed sources dramatically, from approximately 88% Alaskan North Slope (ANS) crude in 1998 to ≈ 62 % imported crude oils that were higher in sulfur than ANS by 2003 and ≈ 77 % imported crude by 2008.[1, 15] The U.S. Chemical Safety Board's investigation found that this switch to higher sulfur, more corrosive crude was a contributing factor in the 6 August 2012 incident.[7]

From 1990–2014 Bay Area refiners built at least 40 million barrels per year of new heavy oil cracking capacity (coking, FCC, and hydrocracking) and, based on the best available estimates by the BAAQMD and California Air Resources Board for this period, their total CO_2e emissions increased by ≈ 3.4 million metric tons per year.[6] This emissions increment from 1990–2014 is linked to that long lasting, higher-emitting infrastructure for refining lower quality oil.[6]

Recently released data from 2014 further confirm a previously reported finding based on data from 2008: a denser crude feed that requires more processing energy than the U.S. average has driven the total greenhouse gas emission intensity of Bay Area refineries higher than the U.S. refinery average. First reported in 2010 based on direct observations,[11] this finding is supported by additional peer-reviewed work[12, 18–22] reported from 2010–2015, and is now further supported by recently reported data from northern California refining industry operations during 2014.[13–17]

Past Estimates of Oil Feed Quality Effects on Refining Energy

Crude oils are complex and widely ranging mixtures of hydrocarbons and contaminants. Crude has larger multi-carbon hydrocarbons, higher carbon and contaminant content, and lower hydrogen content than the major products refiners make from crude, the engine fuels gasoline, diesel, and kerosene jet fuel. These same bulk characteristics make crude oils denser and hydrogen-poor compared with the engine fuels made from them. The differences can be substantial when the wide range of crude oils is taken into account. For example, the average annual crude feeds processed in major U.S. refining centers and California range in density from ≈ 858–902 kg/m^3 as compared with densities of ≈ 737, 814, and 845 kg/m^3 for gasoline, kerosene, and diesel, respectively.[11, 12]

Making engine fuels from crude oils thus requires breaking the larger hydrocarbons in crude into smaller, fuel-sized compounds (cracking), adding H_2 to these hydrogen-poor cracked hydrocarbons, rearranging their chemical structures, and removing their contaminants to protect refinery process catalysts and meet product specifications.[11] Major processes that work harder and process more of the barrel when refining lower quality oil include coking, catalytic cracking, heavy oil hydroprocessing, hydrogen steam reforming of fossil fuels to produce hydrogen needed for that hydroprocessing, and vacuum (heavy oil) distillation.[11, 12, 18–22] These processes use extreme heat, pressure, and chemical energy—notably hydrocarbon feedstock energy conversion to hydrogen and CO_2 in steam reforming, and chemical catalysts that are reactivated by combustion—and are major energy consumers in refineries.[11, 18–21] Consequently, refining lower quality oil increases the processing, energy, and emission intensity of oil refining.

By 2010 peer reviewed research had described the crude feed quality-driven changes in refinery energy intensity quantitatively and showed crude feed quality can predict average multi-plant refinery energy and emission intensity based on real-world U.S. oil refining data.[11] This research[11] compared refinery crude feed, processing, yield, and fuel data from four regions accounting for 97% of U.S. refining capacity during 1999–2008 among regions and years for effects on processing and energy consumption predicted by the processing characteristics of denser, higher sulfur oils. Crude feed density and sulfur content could predict 94% of processing intensity, 90% of energy intensity, and 85% of CO_2 emission intensity differences among regions and years and drove a 39% increase in emissions across regions and years. Fuel energy for processing increased by ≈ 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 refinery products, capacity utilized, and fuels burned were not confounding factors. Fuel energy increments observed predicted that a global switch to "tar sands" oils, should that occur, could double or triple refinery emissions of carbon dioxide from fuel consumption to process the oil.[11]

By 2015 several other independent research efforts quantified oil quality effects on refinery energy intensity using either observed data,[12] or more detailed process-specific modeling based on engineering assumptions and additional details of plausible crude feeds.[18–21] These efforts further supported the effect of oil quality on refinery energy intensity the previous work documented based on U.S. refinery observations,[11] reporting energy and emission intensity effects of similar scale for comparable oil quality, process configuration, and product slate assumptions. Some of these more detailed methods[20–21] may yield more accurate estimates of oil quality-driven energy and emission impacts than the 2010 method,[11] especially for estimating impacts at individual refineries—so long as data those methods require are reported publicly. Cautions against estimating energy and emissions at individual refineries based on oil density and sulfur content alone without considering more detailed plant-specific data appeared in all of this work, and some of it illustrated these plant-level limitations quantitatively.[11–12, 18–21] However, data required for the more detailed methods—such as crude feed hydrogen content, the volume and quality characteristics of specific crude feed distillation fractions, process-level inputs and outputs, and plant-specific product slates—are not yet publicly reported and available for Bay Area refineries.

In 2015 research that assumed up to half of the U.S. crude feed could be replaced by diluted bitumen oils from Canada with only minimal refinery equipment changes found increased petroleum coke combustion could increase $PM_{2.5}$ emissions from FCC units by up to 25 %.[22] These assumptions may not apply to the Bay Area industry—which gets undiluted heavy oils from sources worldwide[15] and has launched major infrastructure projects.[6, 35–39] Also, this research did not estimate refinery-level impacts, and as it notes,[22] it did not estimate SO_2 or $PM_{2.5}$ emissions from refinery-wide burning of the highly contaminated gases that severe coking of bitumen-derived oils can exacerbate.

A 2012 study sponsored by Chevron[23] reported oil quality-driven increases in refinery energy and emissions based on unverifiable estimates that fell below those reported by other work.[11–21] This study[23] assumed a better quality worst-case crude feed than those observed, relied on undisclosed processing assumptions that could not be verified, reported worst-case energy and emission increments smaller than those observed, and made substantial errors in its comparisons with other work.[24–25] For these reasons this study[23] is noted for completeness but is not used in the analysis herein.

Importantly, the estimation method reported in 2010 was shown to predict the average energy intensity (*EI*) of California and Bay Area refineries well. This method[11] uses observed data from U.S. refining regions[†] to estimate refining *EI* based on a given refining region's observed crude feed density, crude feed sulfur content, product slate, and operable crude capacity utilization.[††] It predicted average California refinery *EI* during 2004–2009 within 1 % (5.27 GJ/m^3 predicted *v.* 5.32 GJ/m^3 observed).[12] Further, it predicted the average Bay Area refining *EI* in 2008—which was observed from actual

[†] Observed data inputs include energy intensity *(EI),* the total refinery process energy consumed per volume of crude feed, based on reported fuels consumed in GJ/m^3 crude refined; crude feed density *(d)* in kg/m^3 crude refined; crude feed sulfur content *(S)* in kg/m^3 crude; the utilization of operable atmospheric distillation capacity *(CapUt)* in percent; refined products ratio *(Pratio),* the volume of gasoline, kerosene, distillate, and naphtha divided by that of other refinery products.[11]
[††] Statewide during 2004–2009 all of these data (*d, S, CapUt, Pratio*) were observed actuals; for northern Calif. refineries these data were either observed actuals (2008: *d*, *S;* 2014: *d, S, CapUt*) or West Coast (2008: *CapUt, Pratio*) or statewide (2014: *Pratio*) observed actual data "defaults."

reported Bay Area refining CO_2 emissions of 360 kg CO_2e per m^3 crude and the 68.4 kg CO_2 per GJ emission intensity of the West Coast refinery fuel mix that year—within 1 % (5.31 GJ/m^3 predicted *v.* 5.26 GJ/m^3 observed).[11] In 2011 analysis using more complete Bay Area crude feed and California refinery process fuels and product slate data also showed that this method predicted Bay Area refinery *EI* during 2008 within 1 % of observed statewide *EI* that year.[12]

Data that became available by the summer of 2016[12–17] allow for an additional test of the estimation method reported in 2010[11] for estimating changes in the energy intensity of Bay Area refining based on changes in crude feed quality. These northern California-specific refining industry data are summarized in Table 1.

As shown in Table 1, the energy intensity (*EI*) of Bay Area refining that is predicted by the estimation method reported in 2010[11] based on reported average Bay Area refinery crude feed quality in 2014 is within 2 % of that actually observed from reported refinery emissions in 2014 and average refinery fuels consumed. Moreover, when the relationship of refinery feedstock to refinery products is considered, the sensitivity analysis summarized in the table shows that the method predicts refinery energy intensity well despite residual uncertainty about refinery product slates.

The "sensitivity cases" analyzed assume a ratio of gasoline, diesel, kerosene and naphtha to other refined products (products ratio) that is either 20 % lower or 20 % higher than the average observed statewide from 2004–2009 (the "SC–20%" and "SC+20%" cases in Table 1). This is a very conservative assumption, especially for the –20% case, because the statewide crude feed from 2004–2009 was denser than the Bay Area crude feed in 2014,[12, 14–15] and energy-intensive refining increases the portion of denser crude that is converted to gaseous and solid byproducts instead of engine fuels. Nationwide data show that refinery products ratios tend to decrease with increasing crude feed density and refinery energy intensity, and refinery yield tends to shift, from gasoline and diesel to coke and fuel gas, as crude feed quality worsens and refinery *EI* increases.[11] Indeed, the inverse relationship between products ratio and *EI* (which is weak) is explained in large part by the difficulty of maintaining light liquids yield from much denser crude. Thus, if the Bay Area products ratio in 2014 differed from that observed during statewide refining of relatively denser crude, it most likely was closer to the "SC+20%" case (prediction within 1 % of observation). Moreover, in all cases predicted *EI* is within 5 % of that observed. Therefore, these data indicate the method predicts Bay Area refinery *EI* well.

Table 1. Observed and predicted northern California refining data, 2014.

Data inputs analyzed to estimate (predict) refinery energy intensity

Crude feed quality: Density *(d)*	Crude feed quality: Sulfur content *(S)*	Capacity utilization	Products ratio (Pratio)
891.71 kg/m^3	11.70 kg/m^3	97.7 %	3.871
Based on 55% foreign, 34.7% Californian, and 10.3% ANS (<1% other) N. Calif. crude feed in 2014;[14] and respective foreign,[15] Calif.,[12] ANS[12] crude densities of 869.66, 932.70, 871.40 kg/m^3 and sulfur contents 14.39, 8.03, 9.67 kg/m^3.		From 2014 N. Calif. crude feed and capacity[13, 16] of 46.48 and 47.58 MM m^3.	Ratio of gasoline, diesel, kerosene, naphtha to other products; Calif. avg. from 2004–2009.[12]
Sensitivity case (SC) inputs for possible variability in N. Calif. refinery products ratio (+/– 20 %):		SC – 20 %	3.097
		SC + 20 %	4.645

Actual (observed) and estimated (predicted) refinery energy intensity

Observed energy intensity (*EI*) (GJ/m^3)	Predicted energy intensity (*EI*)	(GJ/m^3)	(Δ from observed)
4.874	Prediction	4.950	+ 1.56 %
	SC – 20 %	5.073	+ 4.08 %
	SC + 20%	4.827	– 0.96 %
From reported emissions of 347.3 kg/m^3 crude run by N. Calif. refineries in 2014,[13, 17] and Calif. average refinery fuel mix emission intensity during 2004–2009 (71.25 kg/GJ).[12]	Estimated from data inputs above in the prediction mode of the 2010 method.[11] SC +20% and –20% data: sensitivity analysis cases above. See Appendix A for details.		

Data from California Energy Commission,[13–14] U.S. Energy Information Administration,[15–16] Union of Concerned Scientists,[12] and California Air Resources Board.[17] Predictions by 2010 estimation method.[11] *See* end notes for full references. Data shown include the Nipomo facility of the San Francisco refinery.

Potential Changes in Bay Area Refinery Crude Feed Quality

A major change in Bay Area and California refinery crude feeds is underway and nearly certain to continue. During 1985–1988 California refiners received 95 % of their crude feed from California and Alaska.[26] Then total combined crude production in these states fell by 65 % from 1988–2014.[27–28] By 2014 these states accounted for only 48 % of statewide[26] and 45 % of Bay Area[14] crude feed. Government[29] and industry[36] analyses confidently predict that the geologic and market factors driving this terminal decline in West Coast oil resources and their replacement with new oil resources will keep driving California crude-feed switching. Further, reliance on these dwindling supplies for 45 % of its current feed shows Bay Area refining will continue to be affected by these factors.

Meanwhile, key differences in the delivery infrastructure for crude acquisition by Bay Area refiners also increase the likelihood of future crude switching here. California crude supplies are delivered to the Bay Area for refining via pipelines.[14] In contrast, the imported foreign oils that comprise 55 % of Bay Area refiners' current crude feed is delivered to them via marine vessels sailing from oil ports worldwide and, to a much lesser but potentially growing extent, via oil trains from the Canadian tar sands.[14] Thus, instead of being "hardwired" into specific crude fields connected to them by pipelines, Bay Area refiners are increasingly able to switch a major and growing portion of their crude feed by choosing among a wide variety of imported oils.

Their wide variety of choices for replacement crude allows Bay Area refiners to acquire, blend, and process future crude feeds that could be of better, similar, or lower quality than those they process now. Indeed, climate constraints—which limit the amounts of fossil fuels than can be burned without risking severe and irreversible societal and economic impacts—suggest that some 40 % of currently proven oil reserves cannot be used,[30] so there is no valid societal reason for using the dirtier-burning portion of the oil resource. In fact, from a societal standpoint, using much more of the so-called "extreme" oils such as tar sands oils does not make economic sense.[30]

However, crude acquisition can account for up to 90 % of refinery operating costs,[7] and price discounts on low quality oil can be substantial. On a barrel-for-barrel basis, from 2004–2015, annual discounts on denser crude (≤ 20 °API *v.* 35.1–40 °API) ranged from 8–28 % of West Coast refiners' crude acquisition costs, and discounts on Canadian Bow River Heavy versus Saudi Arabian Medium *averaged* 18.9 % of West Coast refiners' crude costs.[31–34] Refiners that are able to run bottom-of-the-barrel crude and externalize the associated pollution costs could boost profits on such cost savings. As of 2014 such low-quality (≤ 20 ° API) crude oils accounted for only about 3 % of Bay Area refinery crude imports,[15] however, both globally and regionally, the oil industry has announced plans to refine low quality oil here in much greater volume.

Crude Switch Plans

In 2007 a report in the *Oil & Gas Journal* described industry plans to expand the market for price-discounted oil produced in the Canadian tar sands by, among other things, sending large amounts of it to California refineries as a new potential growth market.[35] By 2009 a paper published by the Society of Petroleum Engineers explained this from a refiner's standpoint, concluding that the Canadian tar sands is "the most promising source for California refineries" to replace dwindling current crude supplies in the long term.[36]

A 2013 Alberta Energy Resources Conservation Board report described projects to send tar sands oil to California if the state's standards allow the resultant emissions, suggesting "90 percent of its refinery capacity" might be "able to process heavier crudes."[37] The same year Valero reported to investors on its "strategy" to refine "cost-advantaged crude oil" and its plan to bring that oil to its Benicia refinery by train.[38] Valero's 2013 report includes a chart showing that Western Canadian Select, a tar sands-derived crude stream, is the most price-discounted crude oil targeted, costing much less than fracked shale oil from the Bakken formations to the south of the Canadian tar sands in the U.S.[38]

A 2013 report to investors by Phillips 66 stated its plans for "moving Canadian crudes down into California … refineries."[39] A 2014 report to investors by Phillips 66 stated its plans to bring this "advantaged crude into California" by train and ship via Ferndale, WA and by train to the Nipomo facility of its San Francisco Refinery (SFR).[40] That project that would bring tar sands oil through the Bay Area via rail for refining at the SFR's Nipomo and Rodeo facilities. A map posted on a Phillips 66 website in 2015 showed crude oil delivery arrows pointing from the Canadian tar sands region to the SFR.[41]

In 2014 Tesoro reported to investors on its projects to "strengthen refinery conversion capability" for "feedstock flexibility."[42] Tesoro also reported greater future production in the Canadian tar sands than any other "key Tesoro market," and that its rail-to-marine terminal project in Vancouver, Oregon would be "competitive with direct rail cost to California."[42]

In 2015, the Canadian Association of Petroleum Producers (CAPP) reported an update on plans to greatly increase tar sands oil exports to California refineries.[43] This CAPP report updated details of its plans to export increasing production of those bitumen-derived oils to the West Coast, including California, via pipeline, boat, and train.[43]

Also in 2015, a report by CBE and ForestEthics[44] identified oil train projects statewide that, collectively, could replace up to 40–50 % of the current statewide California refinery crude feed via new and expanded rail delivery facilities alone.

Crude Switch Projects

Plans for the oil industry's regional crude switch are being implemented piecemeal through site-specific projects. Proposed by various oil companies to build new or expanded capacity for oil delivery, storage, and processing at existing or proposed facilities, these pieces of the larger regional infrastructure project could collectively enable the regional oil feed switch. Parts of this infrastructure have been implemented despite incomplete safeguards against oil switching impacts.[45] These parts include a Richmond refinery heavy gas oil processing expansion, and much the 40 million barrels/year of new heavy oil cracking capacity Bay Area refiners built since 1990.[6] Other parts of the planned infrastructure have not yet been fully implemented: At least 16 northern California oil infrastructure projects that could enable the industry's plans to refine lower quality oil in the Bay Area have been proposed in recent years.

In 2011 the Chevron Richmond refinery proposed a project to further expand its cracking and hydroprocessing capacity for refining heavy gas oil and greatly expand its hydrogen production capacity.[46] Not yet fully implemented, this project was approved with conditions in 2014[46] after a larger project that could have enabled a full-blown switch to refining lower quality crude and gas oils was blocked by state courts in 2009 and 2010 for failure to disclose and address crude switching impacts.[47]

Although the Richmond refinery has existing capacity to acquire all of its oil feed via tanker and barge, Kinder Morgan proposed an oil train-unloading terminal adjacent to the Richmond refinery in 2013. The Air District approved this project in 2014 without adequate public notice and despite the resultant public health hazards.[48] This project expanded the capacity of Bay Area refineries to process tar sands oils and fracked shale oils delivered by "unit" trains dedicated to oil transport, however, a condition of Chevron's 2014 project approval that was adopted by the City of Richmond prohibits Chevron from processing oil delivered by Kinder Morgan Richmond oil train terminal.[46]

In addition to its 2009–2010 heavy gas oil hydrocracking and hydrogen plant expansion[6] discussed above the Phillips 66 San Francisco Refinery (SFR) proposed at least five other interrelated infrastructure expansions. Since 2012 the company proposed a throughput expansion and oil train unloading spur at the SFR's Nipomo facility, a light ends debottlenecking "LPG project" at its Rodeo facility, and three expansions of wharf capacity enabling increased oil imports at its Rodeo facility.[49-50] The interrelated infrastructure expansions proposed could enable the refinery to switch the vast majority of its crude feed to bitumen-derived and fracked oils.[49-50]

During 2015–2016 NuStar Shore Terminals proposed switching over a major portion of its rail-linked ethanol storage and transfer facility at Rodeo to crude service.[51] This proposed oil storage and transfer project would be linked by pipeline to the adjacent Phillips 66 Rodeo refining facility, and could serve other Bay Area refineries as well. It was proposed after WesPac withdrew a proposal for a massive new rail- ship- and pipeline-linked oil storage and transfer facility in Pittsburg that could have served any or all the Bay Area refineries.[52–53]

The Shell Martinez refinery proposed a crude oil storage and wharf capacity expansion that could enable it to acquire larger amounts of low quality imported oil in 2011[54] and, in 2014, proposed a major refinery reconfiguration project.[55] This project appears, based on preliminary information, to enable refining lighter, better quality crude feeds,[55] but the project and its public review have been delayed since 2014[56] for unknown reasons.

In 2009 Praxair proposed a hydrogen pipeline between the Chevron Richmond, Phillips 66 Rodeo, and Shell Martinez refineries that would have supported expanded refining of lower quality oils by supplying more hydrogen for the processing of denser, hydrogen-poor oils.[57] This project was delayed by the company and Contra Costa County review of it lapsed in 2014. Whether this project will be re-proposed is unknown at this time.

Tesoro has proposed a major wharf expansion that could enable its “Golden Eagle” refinery at Avon (near Martinez) to acquire and process lower quality imported tar sands and fracked shale oils in greater amounts.[58] The approval of environmental review for this project by the State Lands Commission has been challenged is still under review in the state courts as of November 2016.

Valero has proposed an oil train unloading project at its Benicia refinery that would enable the refinery to acquire and process up to 70,000 barrels/day of Canadian tar sands oil, an amount equivalent to 45–50 % of its current crude feed, via the proposed new rail infrastructure alone.[59] This project was rejected by Benicia’s Planning Commission, then City Council, in 2016. Whether Valero will appeal this decision remains unknown.

Many of these projects were undisclosed or obscured at first: this list may be incomplete.

Tar Sands Oil Potential

"Tar sands oil" as this term is used herein includes "heavy oil" and "natural bitumen" as defined by the U.S. Geological Survey (USGS).[60] The USGS reports average densities of 957 and 1,030 kg/m^3 and average sulfur contents of 27.8 and 45.5 kg/m^3 for heavy oil and natural bitumen, respectively.[60] Even the low end of this range is much denser and more contaminated than the average Bay Area refinery crude feed in 2014 (892 kg/m^3 density; 11.7 kg/m^3 sulfur).[12, 14, 15] Each of at least 23 geologic basins in at least 16 countries in north and south America, Africa, and north, central, south and southeast Asia holds at least 14.7 billion barrels of these tar sands oils,[60] which is enough to supply 100% of the current Bay Area crude feed[13] for 50 years or longer.

A chart from a California Energy Commission (CEC) analysis[29] that forecast future California crude feed replacement is reproduced as Chart 1. As the chart illustrates, the CEC has projected that ≈ 83 % of the total California refinery crude feed could be imported by 2030 in its "high case" forecast.[29] Note the CEC's "imports" definition:

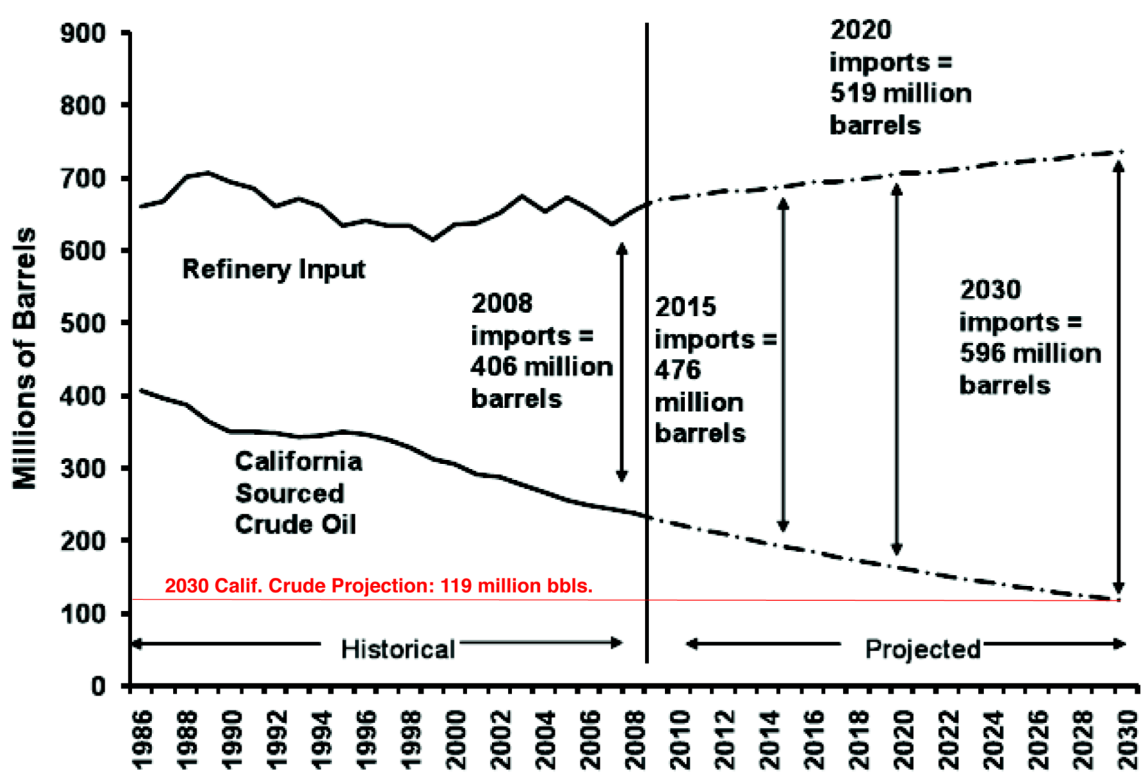

Chart 1. High Case Forecast for California Crude Oil Imports. Excerpted from California Energy Commission Transportation Energy Forecasts and Analysis (Figure 4.8).[29] California sourced oil projection scale in 2030 (red in chart) was added by CBE for reference.

Consistent with refiners' greater flexibility to switch away from current crude sources delivered via boat and train than those delivered via pipeline, this forecast distinguished California-sourced (pipeline) crude from the other sources of crude ("imports") refined. However, the CEC forecast excluded the environmentally relevant, if not crucial, period from 2030–2050, and in addition to continued California supply decline, the CEC "high case" also assumed future refinery production growth that may or may not occur. (<u>See</u> Chart 1.) Separating out that latter assumption, the CEC forecast a 3.2 %/year decline in California crude supply based on historic data in its "high case" (shown) and a 2.2 %/year decline in California supply based on recent years' data in its "low case" (not shown).[29]

Based on the 2.2–3.2 %/year decline in California pipeline crude the CEC forecast,[29] and the amount of this pipeline crude in the 2014 Bay Area crude feed (34.7 %),[14] the Bay Area feed could be 29–30 % pipeline crude (70–71 % "imports") by 2020 and 11–16 % pipeline crude (84–89 % "imports") by 2050. Thus, in oil switching scenarios consistent with the industry plans and infrastructure projects documented above,[31–59] tar sands oil could replace 50–80 % of the current Bay Area crude feed during 2020–2050. Table 2 summarizes data and forecasts for Bay Area crude feed quality in these scenarios.

Table 2. Potential Bay Area crude feed quality in tar sands scenarios, 2020–2050.

Low Case				
Oil source (access mode)	Current 2014 (mixed)	Heavy oil (import)	Bitumen (import)	The quality of the total crude feed is calculated as the sum of the oil sources' feed-weighted data:
Source density	891.71 kg/m^3	957.40 kg/m^3	1033.60 kg/m^3	
Source sulfur	11.70 kg/m^3	27.80 kg/m^3	45.50 kg/m^3	
Percentage of feed	50 %	50 %	0 %	
Feed-weighted density	445.86 kg/m^3	478.70 kg/m^3	—	
Feed-weighted sulfur	5.85 kg/m^3	13.90 kg/m^3	—	
		Low Case crude feed density:		**924.56 kg/m^3**
		Low Case crude feed sulfur content:		**19.75 kg/m^3**
High Case				
Oil source (access mode)	Current 2014 (mixed)	Heavy oil (import)	Bitumen (import)	The quality of the total crude feed is calculated as the sum of the oil sources' feed-weighted data:
Source density	891.71 kg/m^3	957.40 kg/m^3	1033.60 kg/m^3	
Source sulfur	11.70 kg/m^3	27.80 kg/m^3	45.50 kg/m^3	
Percentage of feed	20 %	40 %	40 %	
Feed-weighted density	178.34 kg/m^3	382.96 kg/m^3	413.44 kg/m^3	
Feed-weighted sulfur	2.34 kg/m^3	11.12 kg/m^3	18.20 kg/m^3	
		High Case crude feed density:		**974.74 kg/m^3**
		High Case crude feed sulfur content:		**31.66 kg/m^3**

Based on replacement of 50–80% of baseline 2014 crude feed from Table 1[12, 14, 15] by blends of 50–100% heavy oil with bitumen, and average heavy oil and natural bitumen density and sulfur reported by USGS.[60]

Shading in Table 2 denotes the crude feed calculation: In the low case current and heavy oil sources are each 50 % of total feed, so their "feed-weighted" densities are half their actual (source) densities; adding their feed-weighted densities yields crude feed density.

Both the amount of the current crude feed replaced, and the quality of the oil blends replacing it, affect Bay Area crude feed quality. Table 2 illustrates the combined effects: In the low case 50 % of the current crude feed is replaced by blends of heavy oils that are less dense and contaminated on average than bitumen, further limiting the change in feed quality relative to the high case, which includes additional new bitumen imports. In the high case, 80 % of the current crude feed is replaced by blends of 50% heavy oil and 50% bitumen, thus heavy oil and bitumen is each 40 % of the high case crude feed. In these tar sands scenarios the Bay Area refinery crude feed ranges from ≈ 925–975 kg/m^3 in density and ≈ 19.7–31.7 kg/m^3 in sulfur (2.14–3.25 wt. % sulfur) during 2020–2050.

The potential increase in crude feed density is substantial compared with the densities of Bay Area crude feeds processed in 2014 (≈ 892 kg/m^3)[12, 14, 15] and 2008 (≈ 900 kg/m^3),[11] and is extreme compared with the average U.S. crude feed density during 1999–2008 (≈ 873 kg/m^3).[11] However, refining technology that can process such oil blends exists. In fact, the density of the Shell Martinez refinery crude feed in 2008 (≈ 932 kg/m^3)[12] is within the range forecast here (925–975 kg/m^3).

The potential increase in Bay Area crude feed sulfur content also is substantial and on the same scale some refiners have designed for and processed. The sulfur content of the crude feed refined in Minnesota, Wisconsin, and North and South Dakota in April 1992 (3.16 wt. %),[61] and the design crude feed sulfur content of a project proposed but not built at the Chevron Richmond refinery (3.00 wt. %)[47] are within the range of this forecast (2.14–3.25 wt. %).

Accordingly—in addition to the need for crude source replacement, impetus for cheaper crude, its availability, and the industry's plans and projects that could continue to build for the crude switch forecast herein—the knowledge that some plants have processed roughly similar quality oils further supports the crude feed quality scenarios in Table 2.

Emissions Estimate for Bay Area Tar Sands Refining Scenarios

The direct emissions of air pollutants from oil refining that would be limited by proposed Rule 12-16 are causally, strongly, and positively related to refinery energy consumption.[†] Therefore, increases in these emissions that this rule could prevent may be estimated based on the energy consumed to refine potential lower quality 2020–2050 crude feeds.

These estimates used the peer reviewed method reported in 2010[11] because it is supported by nationwide data, estimated the energy intensity (*EI*) of this refining center well, and could predict *EI* based on publicly available, transparently verifiable, data. The formal method description is available free: http://pubs.acs.org/doi/abs/10.1021%2Fes1019965. Scenario-specific data inputs used in this application of the method were as follows.

- The density (*d*) of the potential crude feeds, in kg/m^3 crude, is the first of four data inputs to the prediction mode of the method. *d* is 924.56 kg/m^3 in the low case and 974.74 kg/m^3 in the high case. <u>*See*</u> pp. 14–16 and Table 2.
- The sulfur content (*S*) of the potential crude feeds, in kg/m^3 crude (the second data input): 19.75 kg/m^3 in the low case and 31.66 kg/m^3 in the high case. <u>*Id*</u>.
- Refinery capacity utilization (*CapUt*), the gross input to atmospheric crude distillation units divided by those units' operable capacity, in percent, is the third input: 90.3 % in both scenarios. This is the statewide average from 2004–2009.[12] This multi-year average spans years of high and low California engine fuels demand, and was used to more reliably forecast potential 2020–2050 operating conditions.
- Products ratio (*Pratio*), the volume of gasoline, kerosene, distillate, and naphtha divided by that of other refinery products (the fourth input): 3.871 in both scenarios; the statewide average[12] for the same period and reasons as for *CapUt.*

Descriptive data from refineries nationwide that support the predictions, and detailed results for *EI,* are given in Appendix B. *EI* predicted in the scenarios was compared with *EI* and emissions observed in 2014.[12, 13, 17, 62] 2014 is the most recent year when this method was shown to predict Bay Area *EI*. These comparisons are given in Table 3.

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† At the points of emission from refineries, the $PM_{2.5}$ precursors NOx and SO_2 are oxidation products of combustion, condensable and filterable PM are combustion products (except for cooling tower PM emissions, which the proposed rule, in any case, would not limit) and CO_2e is ≈ 98.1–99.8% (100-yr GWP)[11] CO_2, a combustion product and, in the case of H_2 plants, emitted by consuming energy to strip H_2 from hydrocarbons in the steam reforming shift reaction.[11]

Table 3. Potential refinery energy and emission intensities of tar sands scenarios.

Results for Energy Intensity (EI)

	EI predicted by crude feed quality[a]			*EI* baseline[b]	Energy ratio (*ER*)
	Prediction (GJ/m^3)	95% confidence (GJ/m^3)	R^2	2014 observed (GJ/m^3)	Scenario : Baseline (ratio)
Low Case	6.802	+/– 0.446	0.90	4.874	1.40
High Case	9.719	+/– 0.654	0.90	4.874	1.99

Results for Emissions

—— Total N. Calif. refining crude feed vol. reported for 2014 (46,479,000 m^3)[c] held constant ——

	Energy Emissions	2014 (*ER* 1.00)[c]		Low Case (*ER* 1.40)		High Case (*ER* 1.99)	
		kg/m^3	tonnes/y	kg/m^3	tonnes/y	kg/m^3	tonnes/y
CO_2e	71.3 kg/GJ	347	16.1 MM	486	22 MM	690	32 MM
$PM_{2.5}$	4.47 kg/TJ	0.022	1,010	0.031	1,400	0.044	2,000
PM_{10}	4.78 kg/TJ	0.023	1,080	0.032	1,500	0.046	2,100
NOx	16.7 kg/TJ	0.081	3,780	0.113	5,300	0.161	7,500
SO_2	9.46 kg/TJ	0.046	2,140	0.064	3,000	0.091	4,200

(a) *EI* of Bay Area refining for crude feeds shown in Table 2 predicted by a peer reviewed method,[11] see Appendix B for details. (b) Bay Area refining *EI* observed in 2014 from Table 1. Energy ratios show that potential refinery *EI* is 1.40–1.99 times that observed. (c) Bay Area refining crude feed[13] and emissions[17, 62] observed in 2014. Energy emissions (emissions per unit refinery energy consumed) are based on observed *EI,* crude feed volume, and emissions in 2014. Potential (low and high case) emissions per m^3 crude refined are estimated from observed 2014 emissions per m^3 crude refined and *ER* data; potential mass emissions are estimated from these kg/m^3 emissions and crude feed volume.

As stated, the range of potential worst-case 2020–2050 Bay Area tar sands scenarios is bounded by a "low case" (50 % more heavy oil; 925 kg/m^3 *d,* 19.7 kg/m^3 *S* crude feed) and a "high case" (80 % more heavy oil/bitumen; 975 kg/m^3 *d,* 31.7 kg/m^3 *S* crude feed). Review of Table 3 reveals very large energy and emission impacts from refining lower quality oil in these scenarios. Refinery energy intensity predicted by the lower quality crude feed is ≈ 1.40–1.99 times the current level (see energy ratio results), and drives production-weighted (kg/m^3 crude) increases of 39–100 % in CO_2e, $PM_{2.5}$, PM_{10}, NOx, and SO_2 emissions from the Bay Area refining industry. See kg/m^3 results in Table 3.

Emitting more per barrel to refine low quality oil could greatly increase regional mass emissions. At current feed volume total annual emissions from Bay Area refiners could increase by approximately 5.9–16 million tonnes of CO_2e, 390–990 tonnes of $PM_{2.5}$, 420–1,020 tonnes of PM_{10}, 1,520–3,720 tonnes of NOx, and 860–2,060 tonnes of SO_2. See tonnes/year results in Table 3.

Discussion

Abundant evidence documents the need for the crude switch that Bay Area refiners already have begun, their impetus, plans and projects for switching to lower priced, lower quality oils, the ability to estimate energy-related emission impacts of this planned crude switch, and its severe potential impacts. In the plausible worst case, switching 50–80 % of the Bay Area refining industry's crude feed to blends of heavy oil and bitumen could increase the industry's particulate and greenhouse gas air pollution by ≈ 39–100 %.

The method used in this estimate has predicted oil quality-driven energy and emission increments from the Bay Area refining industry within 5 %. The oil quality-driven energy and emission increments that the method predicts in this estimate exceed this +/– 5 % power of prediction for the Bay Area industry by ≈ 6.8–19 times.

Other estimates and observations further support this estimate. In 2015 Gordon et al.[21] estimated CO_2e emissions from refining six crude oil streams (≈ 500–630 kg/m^3) that fall within those estimated here (486–690 kg/m^3). $PM_{2.5}$ emissions from the Chevron Richmond and Shell Martinez refineries in 2014 (0.028–0.046 kg/m^3 as compared with crude capacity)[16, 62] approach or exceed those in this estimate (0.031–0.044 kg/m^3). CO_2e emissions from the Shell Martinez refinery reported for 2008 (≈ 497 kg/m^3)[12] exceed the low case emissions in this estimate (486 kg/m^3). Finally, the tenfold increase in oil quality-driven refinery discharges of selenium reported in 2004[4] far exceeds the doubling of emissions reported for this estimate's high case.

The potential switch to tar sands oil would be incremental. Much of the infrastructure that would enable the switch to 50 % heavy oil in the low case has been proposed or built from 1995–2016, and Chevron replaced half of its Richmond refinery's crude feed in five years, after expanding its FCC unit.[1, 6, 15, 46–59] Further, if heavy oil/bitumen blends were to replace the lighter current imports in the Bay Area refinery crude feed instead of its relatively denser California pipeline supply, the density of the crude feed and emissions from refining it could increase more rapidly. The low case emissions thus could occur early in the 2020–2050 forecast period. Meanwhile, the high case requires more oil infrastructure that takes more time to build, and Bay Area refineries may continue to build it piecemeal over decades, before the high case emissions could occur.

Data and forecasting limitations further inform the interpretation and use of this estimate:

Much of the pollution from refining lower quality oil that is asociated with Bay Area refineries is outside the scope of this estimate for direct emissions of energy-related pollutants. Examples include selenium and mercury contamination (<u>*see*</u> pp. 3–4)[4, 9, 10] and exports[63] of the dirty-burning coke byproduct from refining lower quality oil.[11] Future work should address these emissions.

Crude feed volume and "end-of-pipe" engineered controls affect refinery emissions, and the estimate holds those factors constant to better estimate oil quality-driven emissions. This supports addressing emissions related to the other factors in an important way: The estimate supports analysis of the potential for oil quality-driven emission increments to impede or foreclose the ability of other measures to achieve needed emission reductions.

Incomplete publicly reported data for many oil quality characteristics, plant-level product slates, and process-level inputs and outputs limit the reliability of this estimation method for predicting oil quality-driven emissions from individual refineries.[11–12, 18–22] This estimate of the *regional* refining industry's potential emissions should not be interpreted as an equally accurate prediction of potential emissions from individual plants.

Emissions could increase or decrease relative to this estimate if the mix of fuels refiners consume changes. Refiners' choices among hydrogen addition and carbon rejection technologies for converting denser oils to high-value products may change the emission intensity of the refinery fuel mix.[11] CO_2 emission impacts of changes in the refinery fuel mix have been shown to be small compared with those of oil quality-driven changes in energy intensity,[11, 12] however, the potential for changes in refinery fuels to affect other emissions should be addressed.[22] Increased by-production of gases from coking denser oils and bitumen may contaminate fuel gas that is burned refinery-wide, which might increase SO_2 and $PM_{2.5}$ emissions more than estimated here.[22]

Refiners could switch to better quality crude feeds than tar sands oil. This is feasible, less costly to society,[30] and would avoid the huge potential increase in climate and health threatening air pollution from refineries in the Bay Area that is forecast here. The emission limits proposed in Rule 12-16 would prevent this emissions increase and address this uncertainty.

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(57) *See* Expert Report of G. Karras regarding the Contra Costa Pipeline Project, DEIR SCH #2007062007; Department of Conservation and Development (Lead Agency): Contra Costa County, CA. 26 August 2009.

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APPENDICES

A. Details of Predictions for Energy to Refine Lower Quality Oil, 2014.

B. Details of Predictions for Energy to Refine Lower Quality Oil, 2020–2050.

APPENDIX A. Details of Predictions for Energy to Refine Lower Quality Oil, 2014.

PADD	Year	*EI* (GJ/m^3)	*d* (kg/m^3)	*S* (kg/m^3)	*CapUt* (%)	*Pratio*
1	1999	3.451	858.20	8.24	90.9	3.668
1	2000	3.430	860.18	8.00	91.7	3.489
1	2001	3.518	866.34	7.71	87.2	3.479
1	2002	3.426	865.71	7.45	88.9	3.605
1	2003	3.364	863.44	7.43	92.7	3.321
1	2004	3.416	865.44	7.79	90.4	3.397
1	2005	3.404	863.38	7.17	93.1	3.756
1	2006	3.440	864.12	7.17	86.7	3.522
1	2007	3.499	864.33	7.26	85.6	3.443
1	2008	3.551	863.65	7.08	80.8	3.400
2	1999	3.368	858.25	10.64	93.3	4.077
2	2000	3.361	860.03	11.35	94.2	4.132
2	2001	3.396	861.33	11.37	93.9	4.313
2	2002	3.393	861.02	11.28	90.0	4.345
2	2003	3.298	862.80	11.65	91.6	4.281
2	2004	3.376	865.65	11.86	93.6	4.167
2	2005	3.496	865.65	11.95	92.9	4.207
2	2006	3.738	865.44	11.60	92.4	3.907
2	2007	3.800	864.07	11.84	90.1	4.161
2	2008	3.858	862.59	11.73	88.4	4.333
3	1999	4.546	869.00	12.86	94.7	3.120
3	2000	4.563	870.29	12.97	93.9	3.120
3	2001	4.348	874.43	14.34	94.8	3.128
3	2002	4.434	876.70	14.47	91.5	3.251
3	2003	4.381	874.48	14.43	93.6	3.160
3	2004	4.204	877.79	14.40	94.1	3.228
3	2005	4.205	878.01	14.40	88.3	3.316
3	2006	4.367	875.67	14.36	88.7	3.176
3	2007	4.226	876.98	14.47	88.7	3.205
3	2008	4.361	878.66	14.94	83.6	3.229
5	1999	4.908	894.61	11.09	87.1	2.952
5	2000	5.189	895.85	10.84	87.5	3.160
5	2001	5.039	893.76	10.99	89.1	3.231
5	2002	4.881	889.99	10.86	90.0	3.460
5	2003	4.885	889.10	10.94	91.3	3.487
5	2004	4.861	888.87	11.20	90.4	3.551
5	2005	4.774	888.99	11.38	91.7	3.700
5	2006	4.862	887.65	10.92	90.5	3.615
5	2007	5.091	885.54	11.07	87.6	3.551
5	2008	4.939	890.16	12.11	88.1	3.803
Data Inputs for Bay Area Refining in 2014						
Bay Area Refineries Actuals			891.71	11.70	97.7	3.871
Bay Area Refineries (SC – 20 %)			891.71	11.70	97.7	3.097
Bay Area Refineries (SC + 20 %)			891.71	11.70	97.7	4.645

Predictions for Energy Intensity (EI): Bay Area Refining in 2014

		95% Confidence Interval	
For EI (GJ/m^3)	Prediction	lower bound	upper bound
Bay Area Refineries Actuals	4.950	4.553	5.347
Bay Area Refineries (SC – 20 %)	5.073	4.703	5.443
Bay Area Refineries (SC + 20 %)	4.827	4.379	5.276

APPENDIX B. Details of Predictions for Energy to Refine Lower Quality Oil, 2020–2050.

Data Inputs from U.S. Refinery Observations

PADD	Year	*EI* (GJ/m^3)	*d* (kg/m^3)	*S* (kg/m^3)	*CapUt* (%)	*Pratio*
1	1999	3.451	858.20	8.24	90.9	3.668
1	2000	3.430	860.18	8.00	91.7	3.489
1	2001	3.518	866.34	7.71	87.2	3.479
1	2002	3.426	865.71	7.45	88.9	3.605
1	2003	3.364	863.44	7.43	92.7	3.321
1	2004	3.416	865.44	7.79	90.4	3.397
1	2005	3.404	863.38	7.17	93.1	3.756
1	2006	3.440	864.12	7.17	86.7	3.522
1	2007	3.499	864.33	7.26	85.6	3.443
1	2008	3.551	863.65	7.08	80.8	3.400
2	1999	3.368	858.25	10.64	93.3	4.077
2	2000	3.361	860.03	11.35	94.2	4.132
2	2001	3.396	861.33	11.37	93.9	4.313
2	2002	3.393	861.02	11.28	90.0	4.345
2	2003	3.298	862.80	11.65	91.6	4.281
2	2004	3.376	865.65	11.86	93.6	4.167
2	2005	3.496	865.65	11.95	92.9	4.207
2	2006	3.738	865.44	11.60	92.4	3.907
2	2007	3.800	864.07	11.84	90.1	4.161
2	2008	3.858	862.59	11.73	88.4	4.333
3	1999	4.546	869.00	12.86	94.7	3.120
3	2000	4.563	870.29	12.97	93.9	3.120
3	2001	4.348	874.43	14.34	94.8	3.128
3	2002	4.434	876.70	14.47	91.5	3.251
3	2003	4.381	874.48	14.43	93.6	3.160
3	2004	4.204	877.79	14.40	94.1	3.228
3	2005	4.205	878.01	14.40	88.3	3.316
3	2006	4.367	875.67	14.36	88.7	3.176
3	2007	4.226	876.98	14.47	88.7	3.205
3	2008	4.361	878.66	14.94	83.6	3.229
5	1999	4.908	894.61	11.09	87.1	2.952
5	2000	5.189	895.85	10.84	87.5	3.160
5	2001	5.039	893.76	10.99	89.1	3.231
5	2002	4.881	889.99	10.86	90.0	3.460
5	2003	4.885	889.10	10.94	91.3	3.487
5	2004	4.861	888.87	11.20	90.4	3.551
5	2005	4.774	888.99	11.38	91.7	3.700
5	2006	4.862	887.65	10.92	90.5	3.615
5	2007	5.091	885.54	11.07	87.6	3.551
5	2008	4.939	890.16	12.11	88.1	3.803
Data Inputs for Bay Area Refining 2020–2050 Scenarios						
Bay Area Refineries Low Case			924.56	19.75	90.3	3.871
Bay Area Refineries High Case			974.74	31.66	90.3	3.871

Predictions for Energy Intensity (EI): Bay Area Refining 2020–2050 Scenarios

		95% Confidence Interval	
For EI (GJ/m^3)	Prediction	lower bound	upper bound
Bay Area Refineries Low Case	6.802	6.356	7.248
Bay Area Refineries High Case	9.719	9.065	10.372