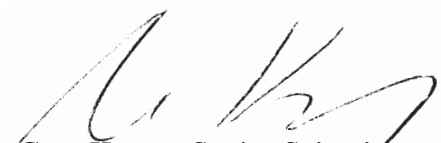


Oil Refinery CO₂ Performance Measurement

Prepared for the

Union of Concerned Scientists

Technical analysis prepared by
Communities for a Better Environment (CBE)



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Executive Summary

Statewide, oil refineries in California emit 19–33% more greenhouse gases (GHG) per barrel crude refined than those in any other major U.S. refining region.

For this report we gathered nationwide refinery data and new California-specific data to analyze refinery emission intensity in California. The goal of the analysis is to compare and evaluate the factors driving the relatively high emission intensity of California refineries.

Petroleum process engineering knowledge was applied to identify factors that affect refinery emission intensity. Data on these causal factors from observations of real-world refinery operating conditions across the four largest U.S. refining regions and California was gathered for multiple years. Those data were analyzed for the ability of the factors and combinations of factors to explain and predict observed refinery emission intensities.

This report summarizes our findings.

Crude feed quality drives refinery energy and emission intensities.

Making gasoline, diesel and jet fuel from denser, higher sulfur crude requires putting more of the crude barrel through aggressive carbon rejection and hydrogen addition processing. That takes more energy. Burning more fuel for this energy increases refinery emissions.

Differences in refinery crude feed density and sulfur content explain 90–96% of differences in emissions across U.S. and California refineries and predict average California refinery emissions within 1%, in analyses that account for differences in refinery product slates.

Analysis of other factors confirms that crude quality drives refinery emissions.

Total fuel energy burned to refine each barrel—energy intensity—correlates with crude quality and emissions, confirming that the extra energy to process lower quality crude boosts refinery emissions. Dirtier-burning fuels cannot explain observed differences in refinery emissions; the same refining by-products dominate fuels burned by refineries across regions.

Increasing capacity to process denser and dirtier oils enables the refining of lower quality crude and correlates with refinery energy and emission intensities when all data are compared, confirming the link between crude quality and energy intensity. But some of this “crude stream” processing capacity can be used to improve the efficiency of other refinery processes, which causes processes to emit at different rates, and process capacity does not predict refinery emissions reliably.

As refinery crude feed quality and emissions increase, gasoline, distillate and jet fuel production rates change little, and in some cases gasoline and distillate yield declines slightly. Product slates do not explain or predict refinery emissions when crude quality is not considered.

An ongoing crude supply switch could increase or decrease California refinery emissions depending on what we do now.

Ongoing rapid declines of California refineries’ current crude supplies present the opportunity to reduce their emissions by about 20% via switching to better quality crude—and the threat that refining even denser, dirtier crude could increase their emissions by another 40% or more.

Purpose, scope, and approach

We set out to identify the main factors driving the high carbon intensity of California’s refining sector. This project evaluates factors that drive refinery emissions, so that one can identify opportunities for preventing, controlling, and reducing those emissions.

Analysis focuses on carbon dioxide (CO₂) emissions from fuels refineries in California. This reflects known differences between fuels refining and asphalt blowing, and the recognition that CO₂ dominates the total global warming potential of GHG (CO₂e) emitted by oil refining (1–3). CO₂ emissions from fuels refining account for 98–99% of 100-year horizon CO₂e mass emitted by oil refining in California (2, 3).

The scope includes emissions at refineries and from purchased fuels consumed by refineries. (Many refiners rely on hydrogen or steam from nearby third-party plants and electricity from the public grid; ignoring that purchased refinery energy would result in errors.) This focus excludes emissions from the production and transport of the crude oil refined and from the transport and use of refinery products. That allows us to isolate, investigate, and measure refinery performance.

At the same time, oil refining is a key link in a bigger fuel cycle. Petroleum is the largest GHG emitter among primary energy sources in the U.S., the largest oil refining country, and in California, the refining center of the U.S. West (3–5). So the “boundary conditions” used here, while appropriate for the scope of this report, are too narrow to fully address the role of oil refining in climate change.

Analysis of key factors driving emissions is based on data from observations of refineries in actual operation. This approach differs from those that use process design parameters to generate data inputs, which are then analyzed in computer models constructed to represent refinery operations. This “data-oriented” approach avoids making assumptions about processing parameters that vary in real-world refinery operation. It also more transparently separates expected causal relationships from observations.

However, this approach is limited to available publicly reported data. We use a ten-year data set encompassing 97% of the U.S. refining industry that was gathered and validated for recently published work (2) as our comparison data. We had to gather and validate the California refinery data ourselves (4, 6–30). The comprehensive six-year statewide data for California refining and facility-level 2008–2009 data we analyze are presented in one place for the first time here (31).

A recently published study used national data to develop a refinery emission intensity model based on crude feed density, crude feed sulfur content, the ratio of light liquids to other refinery products, and refinery capacity utilization (2). This report builds on that published analysis using California data.

For a more formal presentation of the analysis, the raw data, and data documentation and verification details, please see the technical appendix to this report.

Emissions intensity—higher in California

California refineries emit more CO₂ per barrel oil refined than refineries in any other major U.S. refining region.

Figure 1 compares California with other major U.S. refining regions based on emissions intensity—mass emitted per volume crude oil refined. Crude input volume is the most common basis for comparing refineries of different sizes generally (4), and it is a good way to compare CO₂ emissions performance among refineries as well (2).

Consider the *emissions* part of emissions-per-barrel for a moment. This measurement is fundamental to refinery emissions performance evaluation. We need to know where it comes from and if we can trust it.

The bad news: many refinery emission points are not measured. Instead, measurements of some sources are applied to other similar sources burning known amounts of the same fuels to estimate their emissions. This “emission factor” approach makes many assumptions and has been shown to be inaccurate and unreliable for pollutants that comprise small and highly variable portions of industrial exhaust flows. The best practice would directly measure emissions, and apply emissions factors only until direct measurements are done.

The good news, for our purpose here, is that the emissions factor approach is prone to much smaller errors when applied to major combustion products that vary less with typical changes in combustion conditions, like CO₂. This means that in addition to being the best information we have now, the emission

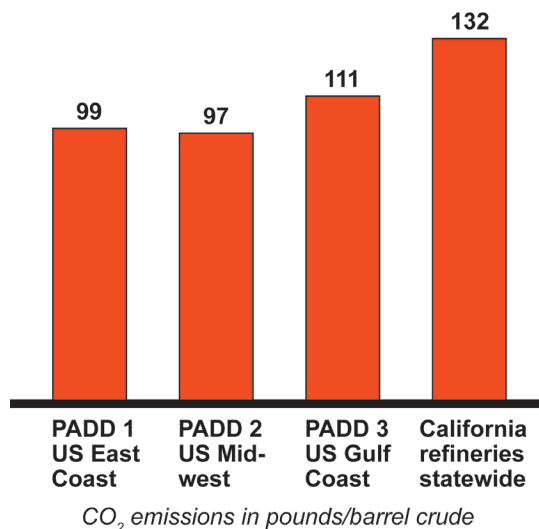


Figure 1. Average refinery emissions intensity 2004–2008, California vs other major U.S. refining regions. Emissions from fuels consumed in refineries including third-party hydrogen production. PADD: Petroleum Administration Defense District. Data from Tech. App. Table 2-1 (31).

factor-based “measurements” we use here for CO₂ (2, 8, 30, 31) are relatively accurate as compared with some other refinery emissions “measurements” you might see reported.

Thus, the substantial differences in refinery emissions intensity shown in Figure 1 indicate real differences in refinery performance. They demonstrate extreme-high average emissions intensity in California. They suggest that other refineries are doing something California refineries could do to reduce emissions. The big question is what *causes* such big differences in refinery emissions.

Energy intensity—the proximate cause of high emissions intensity

California refineries are not burning a dirtier mix of fuels than refineries in other U.S. regions on average. Their high emissions intensity comes from burning more fuel to process each barrel of crude. During 2004–2008 refineries in California consumed 790–890 megajoule of fuel per barrel crude refined, as compared with 540–690 MJ/b in other major U.S. refining regions (PADDs 1–3) (31).

This is consistent with recent work showing that increasing energy intensity that causes refineries to consume more fuel, and not dirtier fuels, increases emissions intensity across U.S. refining regions (2). Increasing fuel energy use per barrel crude refined—increasing energy intensity—is the proximate cause of increasing average refinery emissions intensity.

Looking at where refineries get the fuels they burn for energy helps to explain why energy intensity, and not dirtier fuel, drives the differences in refinery emissions intensity we observe.

The fuel mix shown for California refineries in Figure 2 is dominated by refinery fuel gas, natural gas, and petroleum coke just like in other U.S. refining regions. Coke and fuel gas burn dirtier than natural gas but are self-produced, unavoidable by-products of crude oil conversion processing that are disposed or exported (32) to be burned elsewhere if refineries don’t burn them. Natural gas is brought in when refinery energy demand increases faster than coke and fuel gas by-production. The net effect is that emission per MJ fuel consumed does not change much as refinery energy intensity increases and demands more fuel per barrel processed.

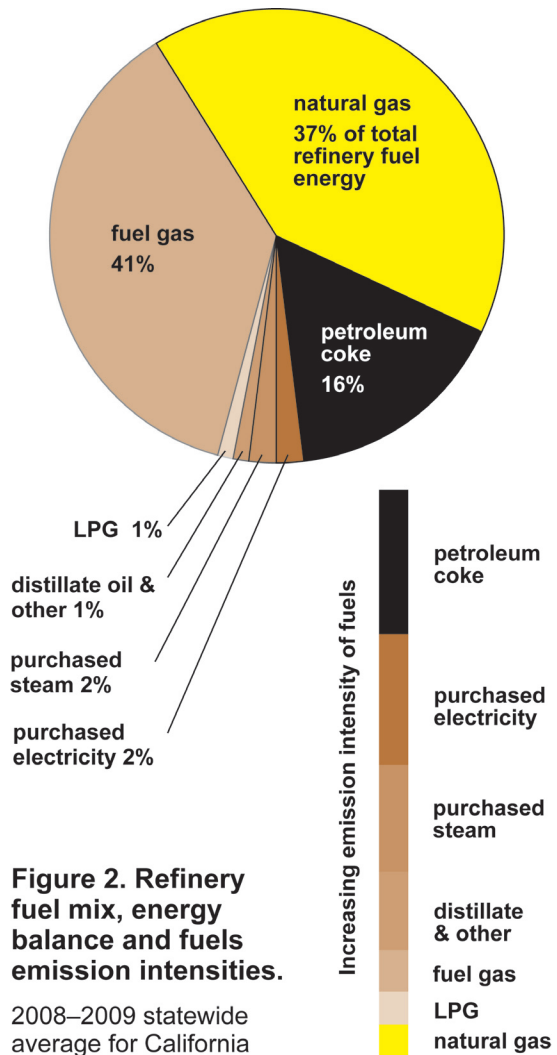


Figure 2. Refinery fuel mix, energy balance and fuels emission intensities.

2008–2009 statewide average for California
Data from Tech. App. (31).

The root cause—making motor fuels from low quality crude

Making motor fuels from denser, more contaminated crude oil increases refinery energy intensity.

A hundred years ago the typical U.S. refinery simply boiled crude oil to separate out its naturally occurring gasoline (or kerosene) and discarded the leftovers. Not any more. Now after this “distillation” at atmospheric pressure, refineries use many other processes to further separate crude into component streams, convert the denser streams into light liquid fuels, remove contaminants, and make many different products and by-products from crude of varying quality (1, 2) But even complex refineries still make crude into motor fuels by the same steps: separation; conversion; contaminant removal, product finishing and blending.

The middle steps—conversion, and removal of contaminants that poison process catalysts—are the key to the puzzle.

Making light, hydrogen-rich motor fuels from the carbon-dense, hydrogen-poor components of crude requires rejecting carbon and adding hydrogen (1, 2, 16, 25). This requires aggressive processing that uses lots of energy. Refiners don’t have to make gasoline, diesel and jet fuel from low quality crude, but when they decide to do so, they have to put a larger share of the denser, dirtier crude barrel through energy-intensive carbon rejection, hydrogen addition, and supporting processes. That aggressive processing expands to handle a larger share of the barrel even when the rest of the refinery does not.

Figure 3 illustrates this concept: Refineries A and B make fuels from the same amounts of crude but Refinery B runs low

quality crude. Their atmospheric distillation capacities are the same, but more of the low quality crude goes through expanded carbon rejection and aggressive hydrogen addition processing at Refinery B. The extra energy for that additional processing makes Refinery B consume more energy per barrel refined.

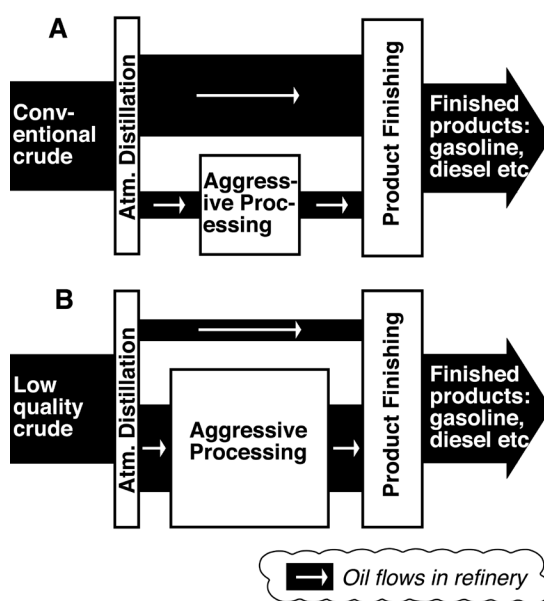


Figure 3. Simple refinery block diagram. Aggressive processing (vacuum distillation, cracking, and aggressive hydroprocessing) acts on a larger portion of the total crude refined to make fuels from low quality crude. Figure reprinted with permission from Communities for a Better Environment.

In fact, as crude feed quality worsens across U.S. refining regions, the average portion of crude feeds that can be handled by refiners’ vacuum distillation, conversion and aggressive hydrogen addition processes combined increases by more than 70%, from 93–167% of refiners’ atmospheric crude distillation capacity (31).

California refineries have more of this aggressive processing capacity on average than refineries in any other U.S. region. Of the five major “crude stream” processes that act on the denser, more contaminated streams from atmospheric distillation (vacuum distillation, coking, catalytic cracking, hydrocracking, and hydrotreating of gas oil and residua), California refineries stand out for four. (Figure 4.) Meanwhile, consistent with the example described above, average California product hydrotreating and reforming capacities are similar to those of other U.S. refining regions.

Vacuum distillation boils the denser components of crude in a vacuum to feed more gas oil into carbon rejection and hydrogen addition processing. Conversion capacity (thermal, catalytic and hydrocracking capacity) breaks denser gas oil down to lighter motor fuel-type oils. Hydrocracking and hydrotreating of gas oil and residua are aggressive hydrogen addition processes. They add hydrogen to make fuels and remove sulfur and other refinery process catalyst poisons.

This aggressive hydroprocessing uses much more hydrogen per barrel oil processed than product hydrotreating (25), especially in California refineries (Fig. 5). That is important because refiners get the extra hydrogen from steam reforming of natural gas and other fossil fuels at temperatures reaching 1500 °F, making hydrogen plants major energy consumers and CO₂ emitters (2, 26, 28, 29, 33, 37).

Hydrogen production increases with crude feed density and hydrocracking rather than product hydrotreating across U.S. refineries (2), and is higher on average in California than in other U.S. regions (31).

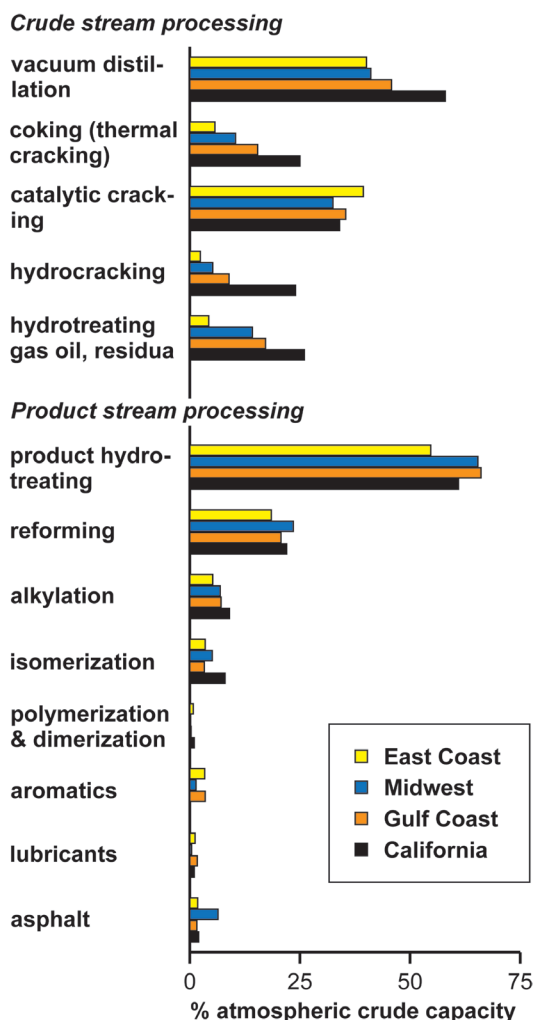


Figure 4. Refinery process capacities at equivalent atmospheric crude capacity, PADDs 1–3 and California (5-yr. avg.) (31).

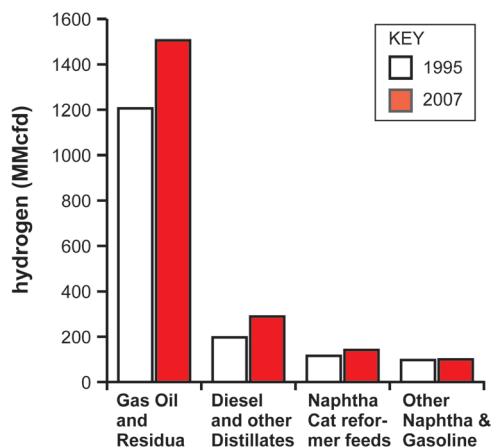


Figure 5. Hydrogen use for hydroprocessing various feeds, California refineries, 1995 and 2007. Figure from CBE (33).

Observations of operating refineries across the U.S. and California reveal the impact of crude quality on refinery energy and emission intensities. Crude feed density increases from Midwest Petroleum Administration Defense District (PADD) 2 on the left of Figure 6 to California on the right. Refinery energy intensity increases steadily with crude feed density. Crude stream processing capacity also increases with crude density, reflecting the mechanism by which refineries burn more fuel for process energy to maintain gasoline, diesel and jet fuel yield from lower quality oil. As a result, refinery output of these light liquid products stays relatively flat as crude density increases.

Figure 7 shows comparisons of the same nationwide data using nonparametric analysis to account for potential nonlinear relationships among causal factors. Crude feed density (shown) and sulfur content (not shown) can explain 92% of observed differences in refinery emissions (Chart A). Together with the light liquids/other products ratio, crude feed density and sulfur content can explain 96% of observed differences in emissions (Chart B). Increasing crude stream processing capacity (Chart C) confirms the mechanism for burning more fuel energy to process denser, higher sulfur crude.

The ratio of light liquids to other products does not explain refinery emission intensity (Chart D). This is consistent with recently published work showing that the products ratio was not significant in the strong relationships among refinery energy intensity, processing intensity, and crude quality (2). Differences in refinery products alone cannot provide an alternative explanation for the large differences in refinery emissions that are observed.

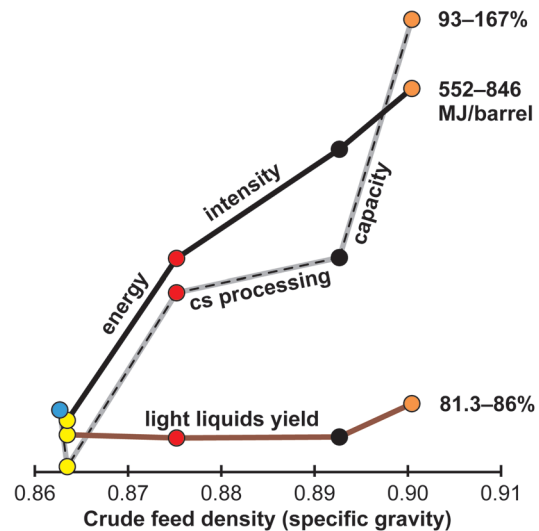


Figure 6. Average energy intensity (MJ/b), crude stream processing capacity (% atm. distillation capacity), and light liquids yield (% crude) by refining region. East Coast PADD 1, 1999–2008 (yellow). Midwest PADD 2, 1999–2008 (blue). Gulf Coast PADD 3, 1999–08 (red). West Coast PADD 5, 1999–2003 (black). California, 2004–2009 (orange). Data from Tech. App. Table 2-1.

But the same differences in product slates that affect emissions only marginally (compare charts A and B) may be more strongly related to processing capacity. PADDs 1 and 5 produce less light liquids than other regions that refine similar or denser crude (compare charts B and D), which should require marginally less crude stream processing capacity in PADDs 1 and 5. Consistent with this expectation, PADD 1 and PADD 5 data are shifted to the left in Chart C relative to their positions in Chart A. Conversely, California maintains light liquids production despite refining denser crude than that refined elsewhere, and the California data are shifted to the right in Chart C. These shifts are independent from any similarly large difference in observed emissions—the data shift horizontally while emission intensity changes verti-

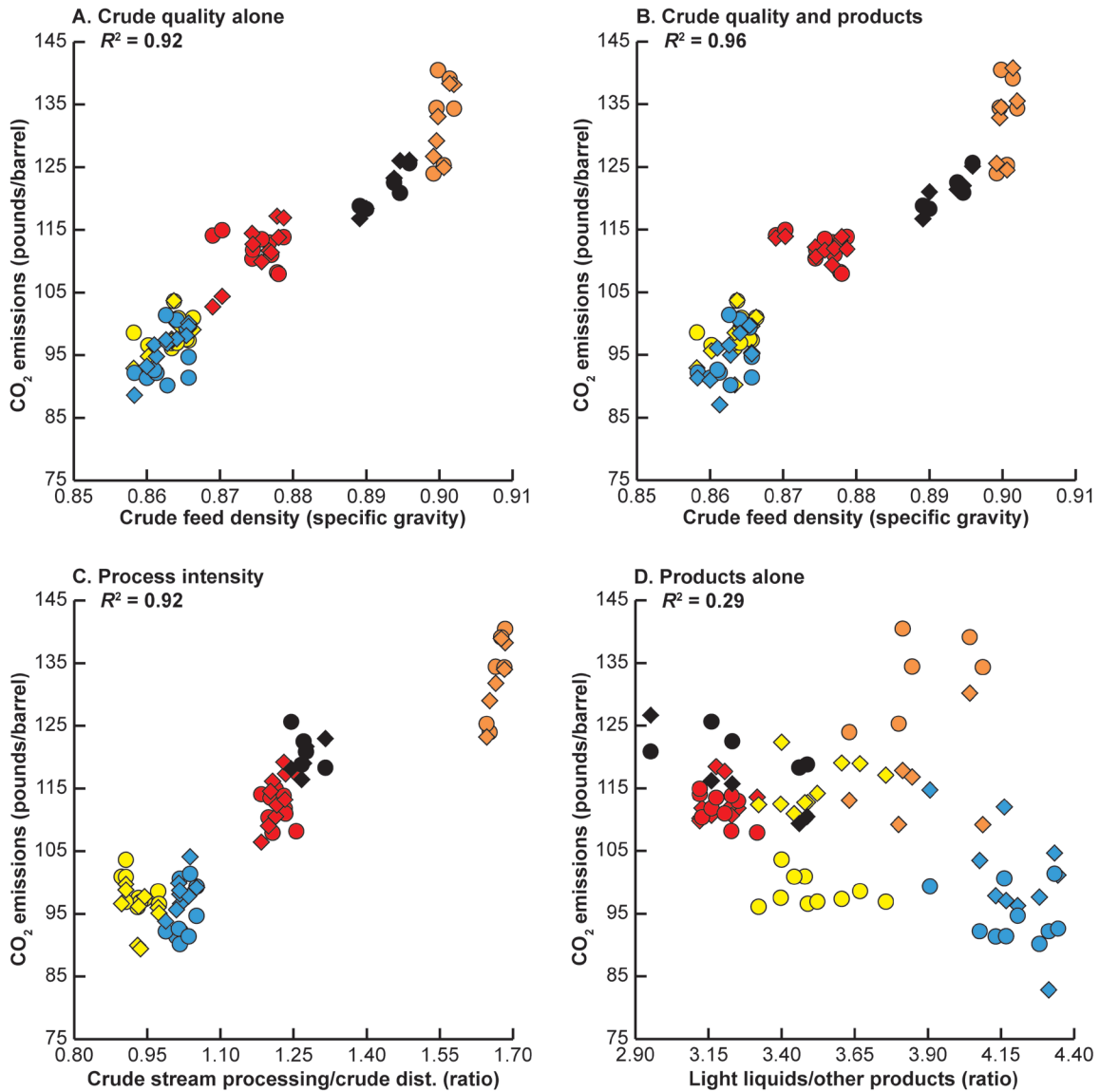


Figure 7. Comparison of refinery emission intensity drivers. Results from nonparametric regression analyses comparing emission intensity with crude feed quality (density, shown; and sulfur, not shown; see Chart A); crude quality and light liquids/other products ratio (B); crude stream processing capacity (C); and products ratio (D). All comparisons account for refinery capacity utilization. Circle [diamond]: annual average observation [prediction] for PADD 1 1999–2008 (yellow), PADD 2 1999–2008 (blue), PADD 3 1999–2008 (red), PADD 5 1999–2003 (black), and California 2004–2009 (orange). Data from Technical Appendix tables 2-1, 2-10.

cally in Chart C—so that at least some of the differences in process capacity do not reflect real differences in emissions.

Thus, observations of operating refineries across U.S. regions and California demonstrate the impact of crude quality on refinery CO₂ emission intensity. However,

while it can enable the refining of lower quality crude, processing capacity does not equate to emissions intensity, because it can be used in different ways to target different product slates, which could require different process energy inputs, and thus emit at different rates.

Drivers of refinery CO₂ intensity: assessing correlations

The petroleum process engineering logic and comparisons of refineries in real-world operation documented above suggest the following model for interactions of the major factors affecting refinery CO₂ emission intensity:

- Making lower quality crude into light liquid fuels consumes more energy and this increases refinery emissions.
- Differences in fuels product slates alone cannot explain differences in emissions when crude quality is not considered. However, light liquids yield that is high or low relative to crude feed quality may reflect differences in crude stream processing capacity and its relationship to energy and emission intensities.
- Crude stream processing capacity can be used to refine lower quality crude, make more light liquid fuels from crude of a given quality, and/or treat other process feeds. Different uses of this processing capacity may consume energy and emit CO₂ at different rates.

If this model is correct, crude quality and fuels products should be able to predict refinery emission intensity. Further, crude quality and products should predict emission intensity better than either refinery products or processing capacity alone. The following analyses test this hypothesis by predicting California refinery emissions based on U.S. refinery data.

Unlike the comparison analyses shown in Figure 7, these predictive analyses use all of the U.S. data and only some of the California data: the California refinery energy and emission intensity observations are withheld. Because the resultant analyses do not “know” the California emissions that are actually observed,

their results represent true predictions of California refinery emissions. Those predictions can then be compared with the emissions actually observed to test the ability of products output, process capacity, and crude quality along with products, to predict California refinery emissions.

This model is taken from previously published work that showed crude quality and fuels produced resulted in reasonably accurate predictions (2). However, the new California data analyzed for the first time here reveal new extremes of high crude feed density, crude stream processing capacity, and refinery energy and emission intensities (31). At the same time, while light liquids yields and crude stream processing capacities are slightly lower relative to crude feed density among some of the previously analyzed U.S. data, those yields and capacities are slightly higher in California. (*Discussion of Fig. 7 above.*) For all of these reasons its ability to predict California refinery emissions based on the nationwide data represents a good test of this model.

Refinery products alone

Total light liquids yield varies little (*Figure 6*) and the light liquids/other products ratio cannot explain differences in refinery emissions (*Figure 7*). However, gasoline, distillate diesel, and kerosene jet fuel are made in different ways that may consume energy and emit at different rates (16, 28, 33–38). Analyzing differences in the relative amounts of individual fuels produced instead of only their lump-sum could provide more information about the relationship of refinery products and emissions. Therefore we test whether the mix of gasoline, distillate, and kerosene

jet fuel produced—the “fuels products mix”—can predict refinery emissions.

U.S. refinery emissions line up with the mix of fuels produced but *decrease* as the portion of refinery emissions caused by differences in fuels produced *increases* (compare charts A and B in Figure 8). This counter intuitive result is caused by decreasing gasoline and distillate yields as crude feed density increases (2) that are reflected in lower light liquid yields as emissions increase among U.S. PADDs (Figure 7). In addition, consistent with the small differences in yields shown in Figure 6, the range of emissions from differences fuels products yields (~10 lb/b) is small compared with that of observed refinery emissions (~50 lb/b; Chart 8-B).

Observed California refinery emissions exceed those predicted based on the fuels products mix by 15–31% annually and by a six-year average of 22%. This prediction error results from equating California to other regions that have a similar mix of fuels yields but lower refinery emissions. These results show that fuels product slates cannot explain or predict refinery emissions when crude quality is not considered, further supporting effects of crude quality on refinery emissions.

Processing capacity alone

This analysis tests the ability of crude stream processing capacity—equivalent capacities for vacuum distillation, conversion (thermal, catalytic and hydrocracking), and gas oil/residua hydrotreating relative to atmospheric crude distillation capacity—to predict refinery emissions. Although products processing or refinery wide processing equivalent capacities provide alternative measurements of refinery “complexity” (Figure 4), crude

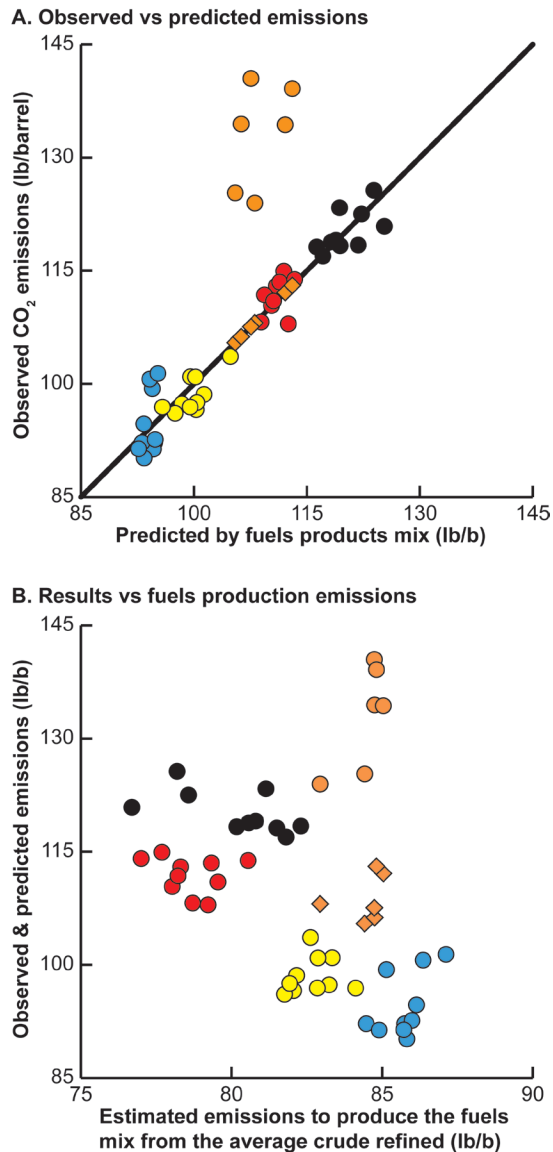


Figure 8. Refinery emission intensity vs gasoline, distillate, and kerosene jet fuel yields. Prediction for California (2004–2009) by partial least squares regression on U.S. data (1999–2008; R^2 0.94). Circle [diamond]: annual average observation [prediction] for PADD 1 (yellow), 2 (blue), 3 (red), 5 (black), or California (orange). Differences in the mix of these products among U.S. PADDs correlate with refinery emissions (Chart A) that cannot be explained by emissions from producing the products alone (Chart B) and do not predict California refinery emissions. Gasoline, distillate, and kerosene production CO₂ estimates (46.0, 50.8, 30.5 kg/b respectively) from NETL (28). All other data from Technical Appendix tables 1-5, 2-1.

stream processing capacity enables refining of lower quality crude and explains refinery energy and emission intensities when all data are compared while products processing and refinery wide capacities do not (2, Figure 7, Tech. Appendix).

Chart A in Figure 9 shows results for the prediction of California refinery emission intensity based on crude stream processing capacity. Although it can explain differences in emissions (*observed PADDs emissions included in analysis*), the prediction based on crude stream processing alone (*observed California emissions excluded from analysis*) exceeds observed emissions by 13–22% and by a six-year average of 17%.

This prediction error can be explained by refiners using processing capacity in different ways. In California, equivalent capacities for coking, hydrocracking and gas oil/residua hydrotreating exceed those of other U.S. regions (Figure 4), and total crude stream processing capacity exceeds atmospheric distillation capacity by an average of 67% (Figure 6), indicating uniquely greater capacity for serial processing of the same oil in multiple crude stream processes. That serial processing can alter the composition of feeds to various processing units, which can alter process reaction conditions, firing rates, and resultant fuel consumption and emission rates.

For example, gas oil hydrotreating capacity adds hydrogen to the H₂-deficient gas oil from vacuum distillation and removes contaminants from the oil that otherwise interfere with processing by poisoning catalytic cracking and reforming catalysts, thereby also removing those contaminants from unfinished products (2, 16, 25). In these ways, inserting more gas oil hydro-

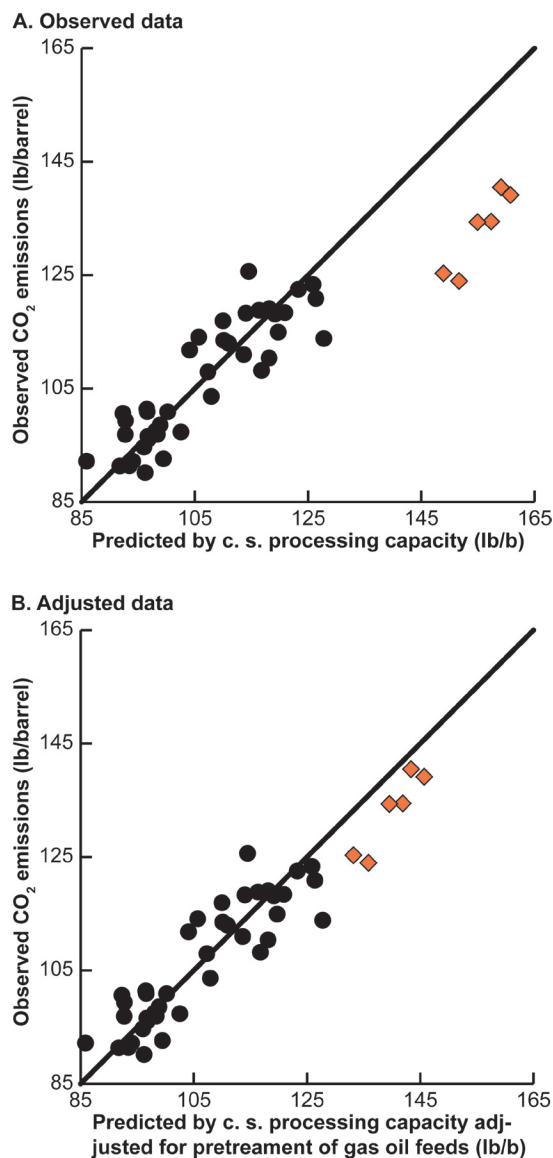


Figure 9. Emission intensity vs vacuum distillation, conversion, and gas oil/residua hydrotreating equivalent capacities. Prediction for California (2004–2009) by partial least squares regression on U.S. data (1999–2008; R^2 0.92). Black circle [orange diamond]: annual avg. for PADD 1, 2, 3 or 5 [California]. Chart A: Prediction based on observed data. Chart B: Identical to Chart A analysis except that California gas oil hydrotreating data are replaced by the lowest equivalent capacity observed among all these regions and years. Hydrotreating gas oil can improve other process efficiencies, so Chart B shows a plausible hypothetical example of why process capacity does not predict California emissions. Data from Tech. App. tables 1-3, 2-1.

treating in the middle of their crude stream processing trains helps refiners make more fuels product from denser and dirtier crude while improving downstream processing efficiency and reducing the need to treat product streams in order to meet “clean fuels” standards.

Thus, California refiners’ very high gas oil hydrotreating capacity (*Figure 4*) is consistent with their abilities to maintain fuels yield despite denser crude and meet California fuel standards despite product hydrotreating and reforming capacities similar to those elsewhere (*figures 4, 7*).

And because improved efficiencies from better cracking and reforming feed pretreatment may offset emissions from this additional gas oil hydrotreating, that may help explain why, relative to other refining regions, average refinery emission intensity does not increase as much as crude stream processing capacity in California.

Chart 9-B explores this plausible explanation. It shows results from the same analysis as Chart 9-A except that observed California gas oil hydrotreating capacity is replaced by the lowest U.S. crude stream hydrotreating capacity observed. Those adjusted California data thereby predict California emissions for the assumed scenario described above, where California gas oil hydrotreating capacity would not increase refinery emissions because its emissions are offset by efficiency improvements in downstream cracking and reforming processes.

In this hypothetical scenario, the prediction based on “adjusted” crude stream process capacity exceeds observed California refinery emissions by a six-year average of 5%, as compared with the 17% average error shown in Chart 9-A.

This hydrotreating example cannot exclude other differences in crude stream processing configuration or usage as causes of the prediction error shown in Chart 9-A. Indeed, the lack of publicly reported data for specific process units that makes it difficult or impossible to verify exactly how much each specific difference in processing changes emissions (12, 28, 34) is another reason why processing capacity alone is not a reliable predictor of refinery emission intensity.

These results support our hypothesis by showing that the ability to use crude stream processing in different ways, which can consume energy and emit at different rates, can explain the poor prediction of California emissions based on observed processing capacity alone.

Crude quality and fuels produced

Recently published work found that crude feed density, crude feed sulfur content, the ratio of light liquids to other products, and refinery capacity utilization¹ explain observed differences in energy and emissions intensities among U.S. refining regions and predict most of the differences among various government estimates of refinery emissions (2). To test our hypothesis, we predict California refinery emissions based on this crude quality and products model (2) using all the U.S. data but only the California crude quality, products, and capacity utilization data.

In addition to the statewide data included in all our analyses, available data allow analysis of individual San Francisco Bay Area refineries. Reported crude feed data are too limited for such facility-level analysis of other California refineries.

¹ Capacity utilization is included as an explanatory factor in all the predictive analyses (figures 8–10).

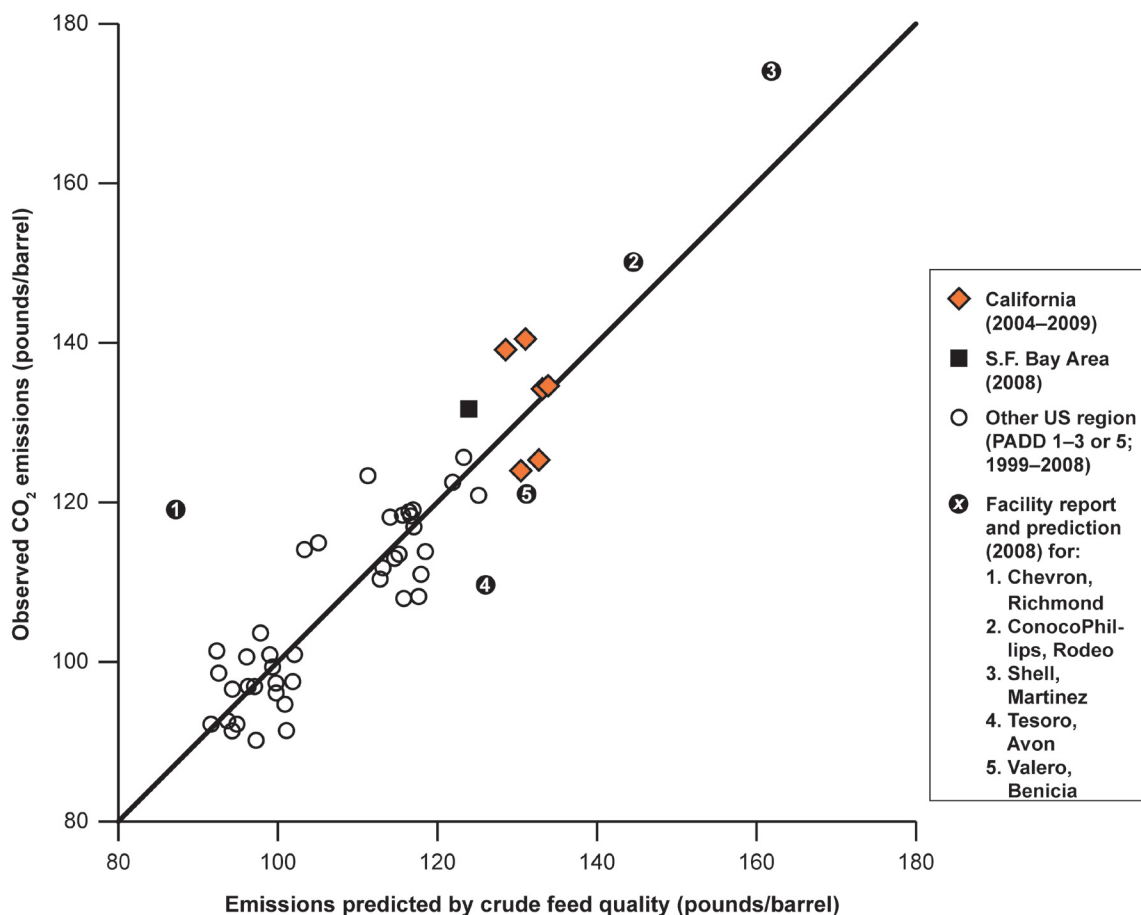


Figure 10. Refinery emission intensity vs crude feed density, sulfur content and light liquids/other products ratio. Predictions for California by partial least squares regression on U.S. data (R^2 0.90). Chart legend identifies annual average data. Data from Tech. App. tables 1-1, 2-1.

The diagonal line in Figure 10 shows the prediction defined by applying this model to the nationwide refinery data. Consistent with our hypothesis, the model tells us to expect increasing emissions intensity as crude feed density, sulfur content, or both increase. Observed emissions fall on or near the line in almost every case. California statewide refinery emissions range from 6% below to 8% above those predicted and are within 1% of predictions as a six-year average. San Francisco Bay Area refinery emissions exceed the prediction by 6%. Emissions reported by four of the five individual Bay Area refineries fall within the confidence of prediction when uncertainties caused by lack of

facility products reporting are considered, and range from 13% below to 8% above the central predictions for these facilities.

The only data point that is clearly different from the emissions predicted by this model is for the Chevron Richmond refinery, and that result was anticipated as Chevron has reported inefficiency at this refinery. A 2005 Air Quality Management District permit filing by the company (39) cited relatively antiquated and inefficient boilers, reformers, and hydrogen production facilities at Richmond.

These results show that the crude quality and products model is relatively accurate and reliable for California refineries.

Crude supply is changing now

California refineries can and do import crude from all over the world (24), but their historically stable crude supply sources in California and Alaska are in terminal decline (40–42). This is driving a refinery crude switch: foreign crude imports were only 6% of the total California refinery crude feed in 1990; in 2009 they were 45% of total California crude feed (21). By 2020 roughly three-quarters of the crude oil refined in California will *not* be from currently existing sources of production in California or Alaska (41, 42).

An urgent question is whether, by 2020, California will switch to alternative transportation energy, or switch to the better quality crude now refined elsewhere, or allow its refiners to retool for a new generation of lower quality crude.

The model developed from analysis of nationwide refinery data that is validated for California refineries in this report predicts that a switch to heavy oil/natural bitumen blends could double or triple U.S. refinery emissions (2). Based on this prediction, replacing 70% of current statewide refinery crude input with the average heavy oil (19) could boost average California refinery emissions to about 200 pounds/barrel crude refined.² This would represent an increase above observed 2009 statewide refinery emissions of approximately 44% or 17 million tonnes/year.

² This prediction for heavy oil as defined by USGS does not represent worst-case refinery emissions; it is near the low end of the heavy oil/natural bitumen range predicted (*ref. 2; SI; Table S8; central prediction for heavy oil*). Nor does it include emissions from crude production: work by others (12, 16, 38) has estimated an *additional* emission increment from extraction of heavy and tar sands oils versus conventional crude that is roughly as great as this emissions increase from refining.

Based on the same prediction model (2), and the average California refinery yield, fuels, and capacity utilization observed 2004–2009 (2, 31), replacing 70% of current statewide refinery crude input with crude of the same quality as that refined in East Coast PADD 1 (2005–2008) could cut statewide refinery emissions to about 112 pounds/barrel—a reduction of about 20%, or ~8 million tonnes/year below observed 2009 emissions.

Comparison with the 10% cut in refinery emissions envisioned by 2020 via product fuels switching under California’s Low Carbon Fuel Standard suggests that this possible range of emissions changes (+44% or –20%) could overwhelm other emissions control efforts.

In light of the findings reported here, the California refinery crude supply switch that is happening now presents a crucial challenge—and opportunity—for climate protection and environmental health.

Recommendations

To ensure environmental health and climate stability it will be necessary to develop and enforce policies that prevent or limit emissions from refining lower quality grades of crude oil.

Existing state and federal policies have not identified crude quality-driven increases in refinery emissions. As a result they have not limited or otherwise prevented very large increases in the emission intensity of refining that exceed the emission targets of these current policies. Continuation of these policies without change will likely fail to achieve environmental health and climate goals.

Expand refinery crude feed quality reporting to include crude oil from U.S. sources.

Currently, every refinery in the U.S. reports the volume, density, and sulfur content of every crude oil shipment it processes, and that is public—but only for foreign crude. (www.eia.gov/oil_gas/petroleum/data_publications/company_level_imports/cli.html) The quality of crude refined from wells on U.S. soil is exempted. Since California's major fuels refineries use U.S. crude too, this hides facility crude quality from the public and from publicly verifiable environmental science. That limits this report's analysis of individual refineries, but very high crude quality-driven emissions found at two of the five facilities analyzed suggest that GHG copollutants disparately impact communities near refineries processing dirtier oil. The public has a right to know about how U.S. oil creates pollution of our communities and threatens our climate. State and federal officials should ensure that the U.S. crude refined is reported just like the foreign crude refined.

Compare refinery carbon emission performance against national or world-wide refinery performance.

The extreme-high average CO₂ emission intensity of California refineries revealed in this report was discovered only by comparing them with refineries in other parts of the U.S. This alone makes the case for rejecting the alternative of comparing refinery performance only within California. Doing that would compare “the worst with the worst,” and thus risk erroneously establishing a statewide refinery emissions rate that is 33% dirtier than the average emissions rate achieved across a whole U.S. refining region as environmentally “acceptable” performance.

Moreover, this report demonstrates that comparing refinery performance across U.S. regions allows one to verify and know which causal factors do and do not drive changes in refinery emissions. That knowledge enables actions to prevent and reduce emissions. This is the *reason* one tracks emission performance.

The crude feed quality and products model evaluated here measures and predicts emissions per barrel crude refined based on the density and sulfur content of crude feeds, refinery capacity utilization, and the ratio of light liquids (gasoline, distillate, kerosene and naphtha) to other refinery products. It is based on data for U.S. Petroleum Administration Defense districts 1, 2, 3 and 5 over ten recent years. Energy intensity predicted by these parameters is compared with fuels data using CO₂ emission factors developed for international reporting of greenhouse gas emissions in the U.S. Data and methods are freely available at <http://pubs.acs.org/doi/abs/10.1021/es1019965>.

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