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U.S. Refinery Efficiency: Impacts Analysis and Implications for Fuel Carbon Policy Implementation

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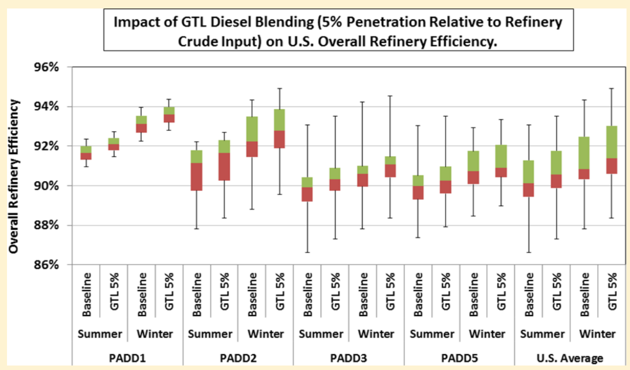
Supporting Information

ABSTRACT: In the next two decades, the U.S. refining industry will face significant changes resulting from a rapidly evolving domestic petroleum energy landscape. The rapid influx of domestically sourced tight light oil and relative demand shifts for gasoline and diesel will impose challenges on the ability of the U.S. refining industry to satisfy both demand and quality requirements. This study uses results from Linear Programming (LP) modeling data to examine the potential impacts of these changes on refinery, process unit, and product-specific efficiencies, focusing on current baseline efficiency values across 43 existing large U.S. refineries that are operating today. These results suggest that refinery and product-specific efficiency values are sensitive to crude quality, seasonal and regional factors, and refinery configuration and complexity, which are determined by final fuel specification requirements. Additional processing of domestically sourced tight light oil could marginally increase refinery efficiency, but these benefits could be offset by crude rebalancing. The dynamic relationship between efficiency and key parameters such as crude API gravity, sulfur content, heavy products, residual upgrading, and complexity are key to understanding possible future changes in refinery efficiency. Relative to gasoline, the efficiency of diesel production is highly variable, and is influenced by the number and severity of units required to produce diesel. To respond to future demand requirements, refiners will need to reduce the gasoline/diesel (G/D) production ratio, which will likely result in greater volumes of diesel being produced through less efficient pathways resulting in reduced efficiency, particularly on the marginal barrel of diesel. This decline in diesel efficiency could be offset by blending of Gas to Liquids (GTL) diesel, which could allow refiners to uplift intermediate fuel streams into more efficient diesel production pathways, thereby allowing for the efficient production of incremental barrels of diesel without added capital investment for the refiner. Given the current wide range of refinery carbon intensity values of baseline transportation fuels in LCA models, this study has shown that the determination of refinery, unit, and product efficiency values requires careful consideration in the context of specific transportation fuel GHG policy objectives.



INTRODUCTION

In the first two decades of the 21st century important investment and policy decisions will need to be made to address global warming.[1] Energy choices made today will likely have a substantial effect upon the composition of the future energy system due to the long lifetimes of technology and infrastructure development.[2] Within this context, policy makers play a key role in influencing investment decisions by incentivizing various alternative technology options.

Increased use of alternative fuels that possess life-cycle Greenhouse Gas (GHG) emissions values lower than crude-oil-derived fuels are being considered by policy makers as a way to decarbonize the average transportation fuel mix.[3] Both the California Low Carbon Fuel Standard[4] (LCFS) and the U.S. Renewable Fuel Standard[5] (RFS) set a carbon intensity standard for petroleum-derived gasoline and diesel, which form the baseline against which potential alternative fuels can be assessed for policy implementation.[6] For example, to qualify under the RFS, a biofuel must meet a minimum reduction in lifecycle GHG emissions compared to baseline petroleum fuels. These specific lifecycle GHG reduction standards range from 20% for conventional biofuels to 60% for cellulosic biofuels.[7] Carbon intensity is the measure of GHG emissions associated with

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producing, transporting, and consuming a unit of fuel energy (e.g., gCO_2e/MJ) on a lifecycle basis. In the transportation sector, given the magnitude of investment decisions that will be required over the next few decades, correctly benchmarking the carbon intensity of crude-oil derived gasoline and diesel is essential.

Despite this, the application of Life Cycle Analysis (LCA) methodology in real-world transport fuel policymaking can be surprisingly problematic. Different LCA models are used in different regions and results from these models can be highly sensitive to definitions of system boundaries, life cycle inventories, process efficiencies, and functional units.[8] BioGrace[9] is used in the European Union (EU) Renewable Energy Directive (RED) program, while the U.S. Environmental Protection Agency (EPA) modeling framework for RFS2 used a series of models to determine the direct and indirect emissions of renewable fuels and petroleum fuels.[10] The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model[11] and its variant is used in California for the California LCFS program, while GHGenius[12] is used in the British Columbia LCFS program and the Alberta RFS program. In some cases, the developers of these models use different approaches to systems boundaries[13] or allocation among different products,[14] which can lead to significantly different results for the same fuel pathway. In other cases, data assumptions between models for similar fuel pathways are fundamentally different.

It is against this background that policy makers continue to strive to obtain more accurate carbon intensity values for conventional gasoline and diesel fuel.[15] Recent trends suggest a greater degree of granularity is being applied to fully represent the variation that exists within these pathways. For example, CARB has recently recognized that average carbon intensity values are not adequate for representing the variance in upstream crude oil extraction GHG modeling.[16] Consequently, a LCA tool for the estimation of GHG emissions from oil production operations (OPGEE) is currently being utilized by CARB to provide an estimate of upstream carbon intensity of 270 individual crude oil producing fields and crude blends.[17]

Inspection of various LCA models reveals a large degree of variation also exists for values of the crude oil refining stage of the lifecycle in baseline gasoline and diesel pathways. Average refinery GHG emissions values range from 7.0 gCO_2e/MJ (Lower Heating Value, LHV, Biograce) to 13.72 gCO_2e/MJ (LHV, California GREET).[18] Notably, the crude refining stage is typically the second highest contributor to the overall lifecycle Well-to-Wheel (WTW) emissions values of gasoline and diesel fuel pathways.

For policy makers to avoid using average values for the crude oil refining lifecycle stage in fuel LCA analysis for policy implementation, a thorough understanding of refining operations and tools to evaluate them is required. In the refining industry, the primary tool for analysis and optimization is the Linear Programming (LP) model. Refiners use this tool on a regular basis to optimize economic margin in their planning; in the future the environmentally motivated demand for reduced GHG emissions could require a refiner to optimize for economic margin which also includes efficiency and/or a GHG emissions variables.

If performed correctly, a U.S. industry-wide LP modeling study of individual operating U.S. refineries could be used to benchmark baseline refinery efficiency and help to understand the implications of the changing domestic U.S. operating environment on refinery GHG emissions. On the supply side, fundamental questions are currently being asked about how the U.S. refining industry can adjust to the rapid influx of U.S domestic tight light oil from numerous shale plays, such as the Bakken and EagleFord. Many U.S. refineries are currently configured to run a blended medium (API < 33) to heavy (API <28) crude slate and for economic reasons it is desirable for a refiner to keep capital intensive units at full utilization. From a demand perspective, U.S. domestic gasoline demand is expected to continue to decline as a result of EPA's Corporate Average Fuel Economy (CAFE) standards,[19] while U.S. domestic diesel demand is projected to remain relatively robust.[3] In particular, the increase in the CAFE standard to 54.5 MPG by 2025, together with more stringent heavy-duty truck fuel economy standards currently under consideration, are believed to more than offset growth in vehicle miles traveled in the foreseeable future in the U.S. This changing dynamic is expected to put pressure on refiners to adjust gasoline/diesel (G/D) production ratios. High-quality hydrogen-rich diesel blendstocks such as Gas to Liquids (GTL) diesel, available from domestically sourced natural gas,[20] could allow a refiner to relieve refinery constraints associated with these changes, produce incremental barrels of diesel, and avoid capital investment in new refinery units.

In this paper, we use results from a U.S. industry-wide LP modeling study of individual U.S. refineries to examine the impacts to refineries of the relevant issues described above. Using a data-rich model derived from LP modeling results, we describe how changes to refinery crude slates, regional and seasonal variation, G/D ratio, and GTL diesel blending could possibly impact refinery, unit, and product efficiencies. We attempt to fill a gap in understanding of U.S. refinery efficiency on both a seasonal and regional basis. Although previous studies[21] have provided important insights into product-specific energy and GHG emissions intensities, they are based on generic or average refinery models that do not accurately represent the various complexities and operational flexibilities in actual operations. Rather than adjusting parameters within a single refinery, this study aims to provide a broad view of the current U.S. refining industry with a focus on current operations of large refineries. Accordingly, the key challenges for refinery policy that we pose are U.S. focused, but may also have broader relevance.

■ EXPERIMENTAL SECTION

Materials and Methods. In the current study, Jacobs Consultancy applied its LP system based on publically available data to perform analysis of 43 U.S. refineries that have an individual capacity of greater than 100 000 bbl/day. This data set represents approximately 70% of the total U.S. refining capacity in 2012. Note that the purpose of this study was not to carry out an extensive statistical analysis, but rather to individually select enough refineries to adequately represent current and future trends within the U.S. refining industry. As such, small refineries (less than 100 000 bbl/day) were excluded from the scope of this study because their configurations do not reflect the majority of U.S. refining capacity. Comprehensive statistical analysis of the U.S. refinery industry is conducted by the U.S. Energy Information Agency (EIA) annually. Our detailed refinery process analysis with a large set of individual refineries is intended to provide insight on individual refining processes to address crude quality and refinery products. The contrast between EIA high-level analysis of the U.S. refinery industry and our in-depth refinery modeling is presented in Elgowainy et al.[22] The LP model was refined and calibrated to highly refined fuels such as reformulated and CARB gasoline and low-sulfur diesel fuels. The models were structured to incorporate Jacobs Consultancy's latest outlook for fuels qualities during the study period. For this study Jacobs developed these models in a Generalized Refining Transportation Marketing and Planning System (GRTMPS) format (licensed by Haverly Systems) which were combined with Jacobs' proprietary refinery technology database. The database and modeling techniques track the crude feed qualities, process operations, intermediate product qualities, and final blending qualities. Additionally, the refinery technology database unit operations are sufficiently complex to provide accurate representations of process units based on the characteristics of the feed.

For each refinery to be analyzed, Jacobs used process submodels which represent the existing refinery configuration. To provide confidence in the modeled base case operation, conversion units (fluid catalytic cracking [FCC], coking [COK], hydrocracking [HYK]) were examined for throughput, conversion, and utilization. These units tend to be fully utilized in an optimized refinery operation. Likewise, crude and vacuum unit throughputs were examined for accuracy and also provide additional validation of the representative crude slate. Recognizing the variation of crude sourcing that most refiners have, Jacobs developed an average crude diet for each configuration consisting of specific crudes that were verified from import data. The balance was made by domestically produced crudes. Approximately 50 crudes were used in the study with 5−7 crudes per individual refinery. Other feedstocks such as gasoline blendstocks, vacuum gas oil (VGO), and residuum were included based on data supplied by EIA.[23]

The product slate was developed based on knowledge of the markets being served by each refinery, making use of EIA data for regional refined product output and product movements between Petroleum Administration for Defense Districts (PADDs), as well as information on product imports. These models were constructed to produce on-specification fuels, including low-sulfur (30 ppm) gasoline, low-benzene (0.62 vol %) gasoline, ethanol 10% (E10) gasoline, Ultra-Low Sulfur Diesel (ULSD, 10 ppm), Texas Low Emissions Diesel (LED), and CARB products for California.

Product blends were analyzed for "typical and expected" specifications and constraints. Gasoline typically runs up against vapor pressure, octane, and sulfur limits. Diesel fuel typically "hits" limits on cold flow (particularly in the winter), sulfur, and, to a lesser extent, viscosity and cetane. ULSD distillate hydrotreating provides cetane improvement via saturation of aromatics in the distillate which often produces a blend that exceeds specification. The model utilized in this study made use of tested correlations for cetane index improvement related to hydrotreater (HDT) operating conditions and feed characterization.

In the current study, refineries were optimized for profit margin, not for emissions, and represent as accurately as possible current U.S. refinery operations. As a result, the price set is a significant driver for the LP model and an important element of the current study. Historical average prices for each region were used on a consistent basis based on Jacobs in-house data. Historical average prices taken over a four year period were chosen to reflect fluctuations in market prices and to smooth the price spike that occurred in 2008. These prices were developed using 4-year historical, seasonal averages for the representative market regions such as U.S. Gulf Coast (USGC) and Chicago.

Multiperiod models were developed that included discrete summer and winter cases. Both gasoline and diesel have different specifications for the summer and winter periods, and thus refinery operations and efficiency can change seasonally. For each refinery, GTL diesel was penetrated at 1%, 3%, and 5% of the crude capacity, respectively.

In this paper, refinery, unit, and product-specific efficiencies were calculated. Refinery efficiency can be defined by considering the energy in all refinery end products divided by energy in all refinery inputs. In this case, refinery inputs include crude oil, natural gas, hydrogen, electricity, blendstocks, and unfinished oils. The unit efficiency is calculated by considering each unit in a refinery, namely the energy present within output streams from a unit divided by energy in input streams to the unit. Output streams could be end products, intermediates, and/or utilities, while input streams include refinery inputs, intermediates, and utilities. Intermediates, such as fuel gas, crude fractions, vacuum gas oil, and vacuum residual oil are fed to other processes. Utilities (e.g., steam and electricity) could be purchased from external sources or produced internally from fuel gas combustion or several exothermic processes. Product-specific efficiency is the efficiency of producing an end product, which can be calculated as energy in an end product divided by energy associated with the production of the end product. Usually, the production of an end product takes one or more processes. The energy associated with the production of the end product is estimated from aggregating energy consumed in the processes of the pathways. Because many processes produce multiple output streams, the energy consumed in these processes is allocated to the output streams by the energy values of the output streams. More detailed information relating to model development, refinery and unit efficiency calculation and allocation methodology used in the current study is presented by Elgowainy et al.[22]

RESULTS AND DISCUSSION

Seasonal and Regional Effects. Figure 1 presents a comparison of weighted average refinery efficiency by season

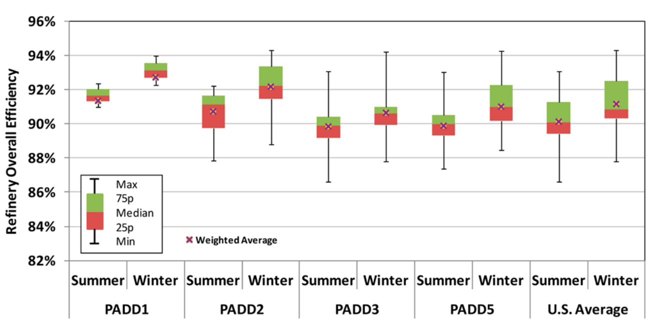

Figure 1. Seasonal variation of overall refinery efficiency by PADD region.

(summer and winter) and by PADD region based on LP modeling data. These results show that overall refinery efficiency ranges from 86.6% to 94.3%. In addition, on average, overall U.S. refinery efficiency is approximately 1% higher in winter than in summer. This uplift in overall refinery efficiency is more pronounced in PADD 1 (1.4%), PADD 2 (1.4%), and PADD 5 (1.1%) than in PADD 3 (0.8%).

These results can be rationalized by the relative ease of refiners to make winter- over summer-grade gasoline. Two key specifications that refiners must meet for gasoline are octane and Reid Vapor Pressure (RVP). Although the octane of a particular gasoline grade is constant throughout the year, the RVP requirement changes with the seasons. RVP limits are lowered to reduce evaporative emissions during the summer months when ambient temperatures are at their highest. Depending on the region, the EPA's standards mandate a RVP between 7.0 and 9.0 pounds per square inch (psi) for summer-grade gasoline.[24] Conversely, winter-grade gasoline has RVP mandated values of around 13 psi. Refiners are capable of meeting these vapor pressure limits in the winter by purchasing relatively inexpensive butane which has a favorable octane rating (Research Octane Number, RON = 93), but a challenging RVP (59 psi, blend value). It is the high RVP which makes butane blending demanding in summer months, but easier in winter months. The butane originates from outside of the refinery gate and thus makes the refinery as a whole more efficient. Additionally, relative to summer months, refiners can reduce the severity (energy demand) of Fluid Catalytic Cracking operations to reduce naphtha output in winter. Overall these changes reduce the overall carbon intensity of gasoline in winter months due to fuel gas consumption and CO_2 emissions from FCC coke combustion. The energy contribution of butane to gasoline production (MJ input per MJ gasoline) is summarized in the Supporting Information (SI).

The trend toward higher gasoline efficiency in winter months is best illustrated in terms of individual product efficiency (Figure 2), which also highlights seasonal efficiency values for diesel and

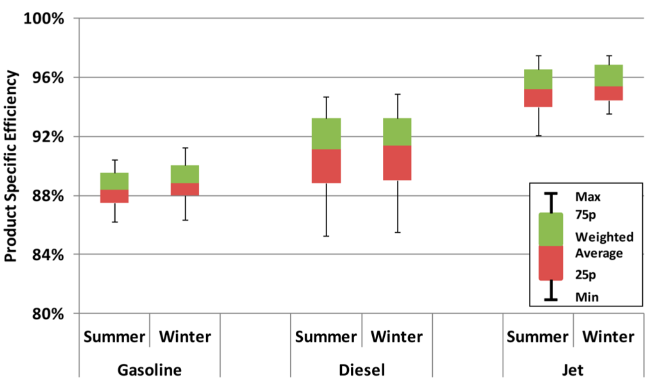

Figure 2. U.S. average seasonal variation of product-specific efficiency for gasoline, diesel, and jet fuel.

jet fuel. Other important seasonal impacts include slightly higher efficiency for diesel and jet fuel production in winter months (average = 91.4% and 95.4%, respectively) compared to summer months (average = 91.1% and 95.2%, respectively). In winter months additional amounts of jet fuel can be blended into the diesel pool to maintain winter diesel cold flow properties.[25] Relative to Straight Run (SR, a component directly from the crude distillation unit) diesel, SR jet fuel generally contains lower levels of sulfur and aromatics. Thus, increased blending of jet fuel into diesel in the winter months reduces hydrogen demand in the ULSD hydrotreater, resulting in a decrease in fuel gas, natural gas and steam demand (see SI).

Inspection of average refinery unit efficiencies reveals negligible seasonal differences (see SI) in most units, with a notable exception being the hydrocracker. In winter months the average hydrocracker efficiency (92.7%) is about 0.3% higher than summer months (92.4%). Due to demand needs, on average, less naphtha is produced from the hydrocracker in winter months, resulting in less conversion and higher efficiency. A comparison of gasoline, diesel, and jet fuel efficiency in PADDs 2, 3, and 5 is shown in Figure 3. Although minor variations exist for gasoline efficiency between each PADD region, the most

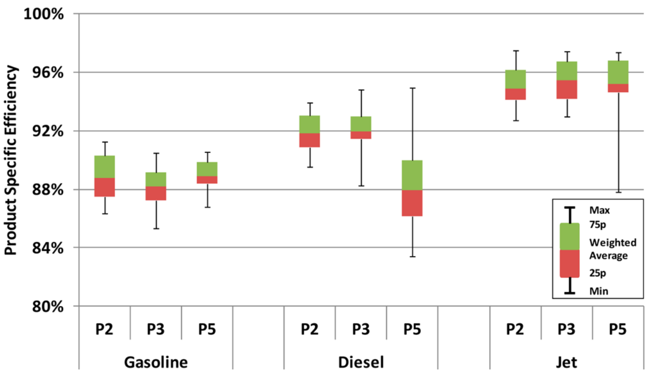

Figure 3. Regional variation of product-specific efficiency for gasoline, diesel, and jet fuel. *P* = PADD Region.

pronounced regional differences are for diesel efficiency. In particular, diesel efficiency in PADD 5 (average = 88.0%) is significantly lower than that in PADD 2 (average = 91.8%) and PADD 3 (average = 91.9%). The lower PADD 5 diesel efficiency relative to other PADD regions can be attributed to tighter aromatic specifications associated with CARB diesel[26] relative to ULSD[27] and complex refineries in California running on average a relatively heavy crude mix. The relatively larger heavy crude share in California refineries is due in part to the heavy crude production in California's central valley oil fields. In comparison, PADD 2 refineries have a large share of heavy crude, which mainly originates from Canadian oil sands. A comparison of diesel balances reveals that relative to refineries in other PADD regions, California refineries have a larger share of hydrocracker distillate within the final diesel pool. Furthermore, California refiners also have a higher percentage of aromatic saturation units which is an additional hydroprocessing step that, as the name implies, saturates aromatics. Lower aromatic levels are required for California diesel (CARB diesel) compared to the rest of the U.S. Notably, relative to other PADD regions, California refineries are on average more complex and have a greater yield of heavy products (see SI). Importantly, these aromatic saturation units have low (∼ 95%) efficiencies relative to other units. Put together, these results highlight seasonal and regional variation in overall, unit, and product-specific efficiencies, which are heavily influenced by endproduct specifications for both gasoline and diesel.

Crude Sourcing. As described above, domestic production of tight light oil in the U.S. has grown dramatically over the past few years, from approximately 300 000 barrels per day (bpd) in 2007 to more than 2 000 000 bpd in 2013.[3] U.S. tight light oil production is projected to lead to a growth in domestic oil production of 2.6 million barrels per day between 2008 and 2019.[3] Tight oil from these shale plays is typically very light (API 40−50) and has comparatively low levels of sulfur (ca. 0.1−0.2%) relative to imported light sweet crudes (ca. 1.5%).[28] In reality, however, due to the rapid growth rate and large number of producers, the Bakken and Eagle Ford tight oil crude quality is currently highly variable.[29] In general, the more consistent and predictable the crude quality, the greater value it is to a refiner.

Because U.S. oil companies are legally prohibited from exporting crude to other nations,[30] domestic tight oil must be processed within U.S. refineries. For more than two decades U.S. refining investments have been made to enable the additional

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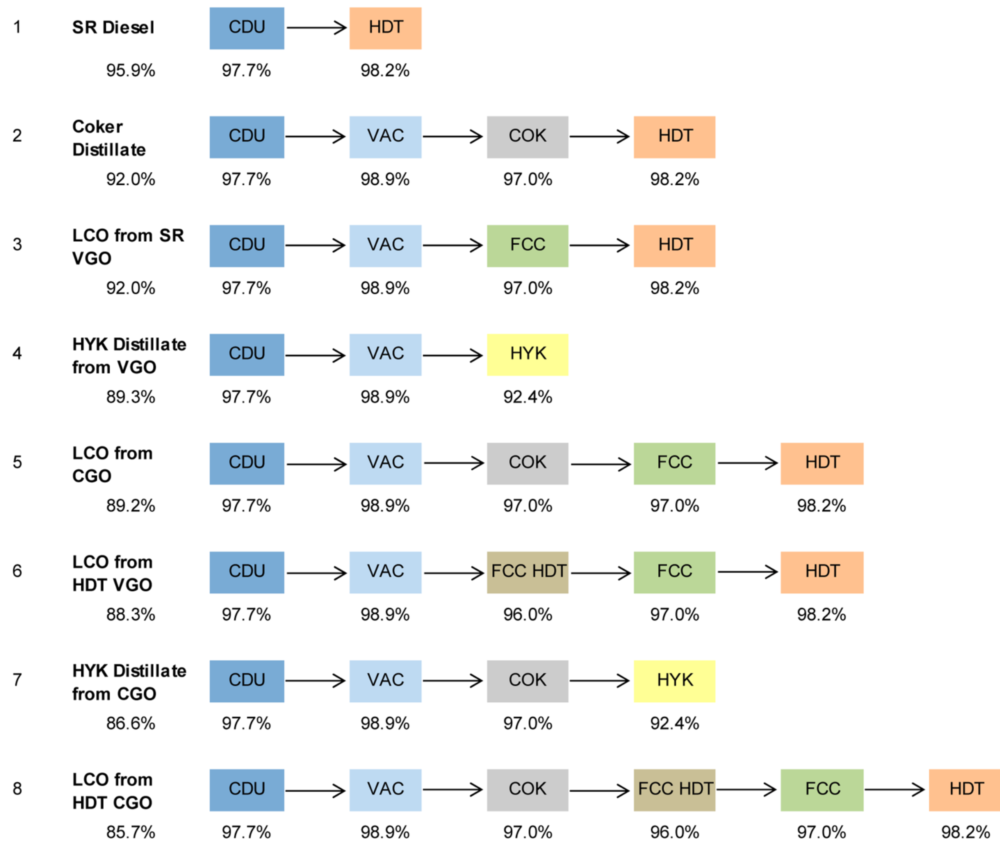

Figure 4. U.S. average efficiency of individual diesel pathways using average unit efficiency values. CDU = Crude distillation unit; VAC = vacuum distillation unit; COK = coker; FCC = fluid catalytic cracker; HDT = hydrotreater; HYK = hydrocracker; FCC HDT = fluid catalytic cracker hydrotreater. California refineries that include aromatic saturator units are not included.

processing of heavy, high-sulfur oils, in anticipation that a widening future light–heavy spread would justify such investments. In the past 5–7 years alone, more than $30 billion was invested in U.S. refineries to expand capacity to process heavy crude oils from Canada and the Middle East.[31] Ultimately economics (price of domestic tight oil crude relative to other crudes) will dictate refineries volumes and strategy. In broad terms, tight light oil will compete against imported Middle Eastern or West African sourced crudes and thus in the short term cheaper domestic tight oil will displace light sweet crude from foreign sources. Over the past 15 years, the API gravity of crude oil processed in U.S. refineries has averaged between 30 and 31 degrees. With increasing U.S. production of light crude produced from tight formations, refiners will need less imported light oil to maintain optimal API gravity.

This simple displacement within U.S. refineries is already occurring and is possible to varying degrees in different PADD regions (see SI). Recently, Valero Energy replaced all of its foreign light oil imports with domestic crude at its Gulf Coast and Memphis, Tennessee refineries during the fourth quarter of 2012.[32] Phillips 66 is no longer taking light sweet crude imports at its three U.S. Gulf Coast refineries and has met its sweet demand along the Gulf Coast with more profitable domestic sweet crude, including Eagle Ford and Bakken.[33] In addition, Marathon Petroleum in January 2013 disclosed plans to boost profits by displacing foreign crude oil imports at its Gulf Coast refineries, shipping more Bakken and Canadian crude to its Midwest plants, and outfitting its Ohio and Kentucky facilities to process more Utica shale oil and condensate.[34]

In an effort to understand the impact of this simple light crude displacement scenario on refinery efficiency, a refinery efficiency regression formula (eq 1) was applied.[22] This regression formula shows that overall refining efficiency increases with lower crude sulfur content and higher API. Note that the parameters in eq 1 are dynamically correlated and are only representative of the complex U.S. refineries.

$$\eta_{\mathrm{LHV}} = 87.59 + 0.2008 \times \mathrm{API} - 0.7628 \times S + 0.07874 \times \mathrm{HP} - 0.1847 \times \mathrm{CI} \qquad (1)$$

where

η_{LHV} is the refinery overall efficiency on the LHV basis in %;

API is the API gravity of crude oil;

S is the sulfur content of crude oil in % by weight (e.g., for sulfur content of 6%, $S = 6$);

HP is the heavy products yield in % by energy (e.g., for heavy products of 5%, HP = 5);

and CI is the actual utilized complexity index of the refinery.

Lower levels of sulfur that are present in tight light oil relative to the displaced light sweet crude would likely reduce the refiner's overall sulfur load, produce intermediate streams with lower levels of sulfur, and reduce the overall severity of hydrotreating. The capacity for sulfur reduction is greatest in PADD 2 and PADD 3, reflecting the greater relative quantities of heavy sour crudes imported into those regions (see SI).

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Despite this, relative to the other parameters, the contribution of sulfur % to overall efficiency is relatively small. For example, if a refiner substituted a light sweet crude with a light crude produced from domestic tight formations, and if all the other efficiency parameters stayed constant, then a reduction in total crude sulfur by 1.3% (i.e., from 2.5 to 1.2%) results in an increase in refinery efficiency of 1% (i.e., from 90 to 91%). However, in reality, since the light component is only 20−30% of the total crude slate, the increase in refinery efficiency from simple light crude substitution would likely be less than 1%.

Beyond simple crude substitution, consistent with eq 1, a refinery processing greater amounts of domestic tight light oil could theoretically realize increased overall efficiency by increasing crude API, lowering sulfur, and producing less heavy components while decreasing complexity. In reality, however, this may not be realized in the magnitude described above. For example, domestic tight oil could enable a refiner to process greater quantities of medium or heavy sour crudes, which would ensure cokers remain fully utilized and maintain robust distillate production. This scenario could neutralize any efficiency gains associated with incremental quantities of domestic tight oil. Thus, the theoretical efficiency gains implicated with increased refining of tight oil that are associated with adjustments in API gravity, sulfur, and heavy products could very well be offset by financial realities associated with optimal refinery operation.

Diesel Production. According to EIA, more stringent efficiency standards for Light Duty Vehicles (LDVs) will require new LDVs to average approximately 49 mpg in 2025.[3] This is forecast to contribute to a decline in future gasoline consumption. In contrast, diesel demand, which is linked to GDP growth,[35] is forecast to trend in the opposite direction, although a significant amount of future diesel consumption could be offset by a combination of fuel efficiency gains in Heavy Duty Vehicles (HDVs) and partial replacement by Natural Gas Vehicles (NGVs).[36]

This decrease in gasoline consumption, combined with growth in diesel demand, is forecast to lead to a shift in refinery outputs and investments to distillate fuels. This will be reflected in a change in the G/D ratio production in U.S. refineries. The EIA projects that on average the G/D ratio in U.S. refineries will decline from 2.1 in 2012 to 1.6 after 2035.[3] To produce additional diesel barrels, in the absence of additional capital investment a refiner could purchase crudes that contain a larger diesel cut. These types of crudes, however, are typically priced higher than crudes that contain smaller distillate cuts. Other options include dropping jet fuel into the diesel pool, however this sacrifices jet fuel that is typically priced higher than diesel on a mass basis. Other options include dropping some of the heavy gasoline range material into the jet pool if this is not already maximized. A refiner could also run the FCC at a lower conversion rate to increase production and widen the production cut of Light Cycle Oil (LCO) for diesel production and produce less gasoline. Beyond these measures, to further decrease the G/D ratio a refiner would need to increase installed gas oil hydrocracking capacity, which implies capital investment and a shifting of FCC feeds to hydrocrackers in order to maximize diesel production. Given these issues, key questions arise about the change in efficiency of U.S. refineries that could result from future increasing amounts of distillates being produced relative to gasoline.

As mentioned above, results from the 43 studied refineries (Figure 2) reveal a surprisingly large range in diesel efficiency relative to gasoline and jet fuel efficiencies. To understand this variation and the possible future direction of average U.S. diesel efficiency at a deeper level, individual refinery unit efficiency values were used to calculate individual diesel pathway efficiencies (Figure 4). These results show that individual diesel pathway efficiency values can range from 95.9% (pathway 1) to 85.7% (pathway 8). In general, reduced severity and number of units required to make diesel relates to higher efficiency. For example, SR diesel (efficiency = 95.9%) is produced from only two relatively efficient units (crude distillation unit, CDU, 97.7% and ULSD hydrotreater, HYT, 98.2%). In contrast, diesel production is less efficient if intermediate streams, such as VGO and LCO, are processed through multiple units (e.g., pathways 5−8, Figure 4). Over most pathways considered, diesel efficiency is higher than gasoline efficiency (Figure 2).

Importantly, each refinery will likely not have access to every diesel pathway shown in Figure 4. For example, hydrocrackers (HYKs) are not as common in U.S. refineries compared to FCCs. In addition, these diesel efficiency values are averages from 43 refineries and thus the efficiency of each diesel pathway would likely change with different unit operations. Each refinery will have different quality feeds to produce diesel, which will contain different amounts of aromatics. Thus, feed composition will impact hydrogen demand for each diesel pathway, which in turn will change diesel hydrotreater efficiency.

Very few refinery diesel blends are made up 100% of any single pathway presented in Figure 4, thus in reality the actual diesel efficiency within the refinery will be a volumetric blend of a number of the individual diesel pathways presented here. Table 1 shows three volumetric diesel blend scenarios within (a) a heavy coking refinery, (b) a sour coking/hydrocracking refinery, and (c) a complex light coking refinery, respectively. In these cases, the relative contribution of relatively efficient SR diesel can vary depending on the refinery configuration. Of note, in the case of the sour coking/hydrocracking refinery (scenario b), the proportion of SR diesel to the total ULSD pool is relatively low (46%), resulting in a lower overall diesel efficiency compared with scenarios (a) or (c).

As mentioned above, a decrease in gasoline consumption combined with growth in diesel consumption will require refiners to produce additional amounts of distillate fuels to meet a growing demand for diesel. Without additional capital investment, a refiner could, for example, reduce the severity of the FCC unit and thereby produce less naphtha for gasoline and more LCO for diesel. By implication, this will result in additional diesel produced through relatively lower efficiency pathways (e.g., Pathway 6, Figure 4). Table 1 shows that if a refiner invests in a HYK unit to produce incremental diesel, then this will likely result in a reduced share of relatively efficient diesel, such as SR diesel.

Blending of Gas to Liquids (GTL) Diesel. Similar to the way gasoline utilizes imported blendstocks, blending of GTL diesel could have implications on the intensity of certain refining processes, particularly in the future when U.S. refineries will face new challenges relating to shifting G/D demand. In most U.S. refineries quality constraints could potentially limit diesel and jet fuel production. These constraints include smoke point and aromatics in jet fuel, cetane index, density, cold flow properties and viscosity in diesel fuel, and sulfur content in most of the distillates. In the future, high cetane, zero aromatic, and zero sulfur blendstocks such as GTL diesel could be utilized by U.S. refiners to relieve these constraints and produce incremental barrels of diesel without added capital investment for the refiner.[37] GTL diesel contains ultra low concentrations of sulfur

Table 1. Volumetric Blends of Individual Diesel Pathways in Representative Refineries[a]

diesel pathway	description	percentage	efficiency
(a) ULSD Pool From Heavy Coking Refinery			
1	SR diesel	63%	95.9%
2	coker distillate	22%	92.0%
3	FCC LCO from SR	4%	92.0%
6	FCC LCO from HDT SR	7%	88.3%
8	FCC LCO from HDT CGO	4%	85.6%
	total diesel pool	**100%**	**94.0%**
(b) ULSD Pool From Sour Coking Refinery			
1	SR diesel	46%	95.9%
2	coker distillate	27%	92.0%
4	HYK from VGO	27%	89.3%
	total diesel pool	**100%**	**93.1%**
(c) ULSD Pool From Light Coking Refinery			
1	SR diesel	62%	95.9%
2	coker distillate	15%	92.0%
3	FCC LCO from SR	18%	92.0%
8	FCC LCO from CGO	4%	85.7%
	total diesel pool	**100%**	**94.1%**
(d) ULSD Pool From Light Coking Refinery With GTL Blending			
1	SR diesel	73%	96.7%
2	coker distillate	11%	92.0%
3	FCC LCO from SR	13%	92.0%
8	FCC LCO from CGO	3%	85.7%
	total diesel pool	**100%**	**95.2%**

[a]SR = Straight-run; FCC = fluid catalytic cracker; LCO = light cycle oil; HDT = hydrotreater; CGO = coker gas oil; VGO = vacuum gas oil; HYK = hydrocracker.

and aromatic components,[38] consequently, the cetane number of GTL diesel is high and its density is relatively low compared to crude oil refined diesel. Diesel produced from heavy crude oil may contain high concentrations of aromatics and may have a fairly low cetane number and high product density. GTL diesel has very good qualities to compensate these heavy specifications and good cold flow qualities, which are particularly valuable for winter diesel production.

A refiner could utilize GTL diesel in many ways to relieve the constraints described above. In general, diesel blending constraints are controlled by balancing the volumes and qualities of SR diesel, LCO, and coker distillate. Blending GTL diesel may allow a refiner to upgrade lower-quality streams into the diesel pool, for example, by lifting heavy atmospheric gas oil (AGO) from an FCC feedstock up to the SR diesel. Blending GTL diesel can also potentially reduce residual fuel production because cutterstocks such as jet fuel and LCO can be reoptimized within the refinery; for example, the higher cetane value of GTL diesel could allow LCO to go to the ULSD hydrotreater, rather than to a hydrocracker. Because GTL diesel can potentially be a broad cut to include both jet and diesel, blending of GTL diesel can allow refiners to meet tighter winter diesel specifications without compromising higher value jet production.

To understand the potential impact of blending GTL diesel on U.S. refinery efficiency, the effect of blending volumes of GTL diesel at 1%, 3%, and 5% of refinery crude feed (on crude volume) was investigated by LP modeling and compared against the base case efficiency values without GTL diesel blending in 43 U.S. refinery models. Note that in all cases the LP models were set to maximize the refinery profit margin, not efficiency.

Figure 5 shows the impact of blending 5% GTL diesel on U.S. refinery efficiency by PADD region and season. Across the 43

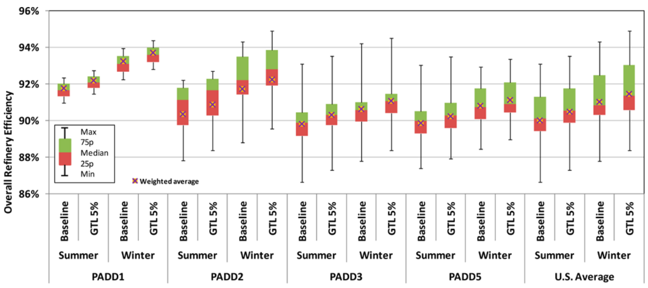

Figure 5. Impact of GTL diesel blending (5% penetration relative to refinery crude input) on U.S. average overall refinery efficiency.

refineries studied, penetration of 5% GTL diesel increased overall refinery efficiency by approximately 0.5%. Directionally, the increase in refinery efficiency that results from blending of GTL diesel is consistent with the previously discussed linear regression model (eq 1). In particular, relative to the base case, introduction of GTL diesel into a refinery can increase overall API gravity of inputs and reduce sulfur content, heavy products, and complexity.

The impact of GTL diesel blending on product specific efficiency is illustrated in Figure 6. These results suggest that only

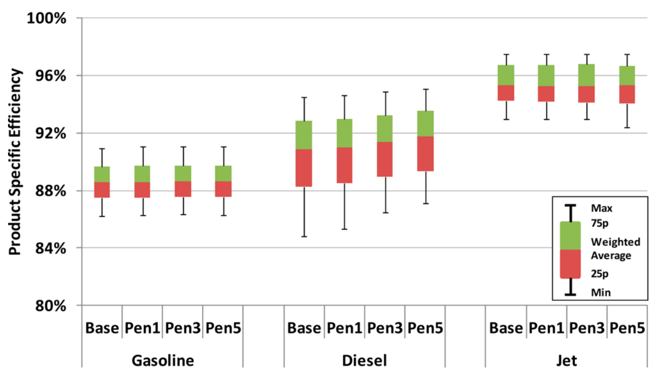

Figure 6. Impact of GTL diesel blending (1%, 3%, and 5% penetration relative to refinery crude input) on product-specific efficiency. Base = Basecase efficiency without GTL blending; Pen = penetration (of GTL diesel).

diesel efficiency is positively impacted by GTL diesel blending. Across all 43 refineries studied, penetration of 5% GTL diesel increases average diesel efficiency by approximately 1%. Of note, GTL diesel blending appears to have a significant impact on refineries that produce diesel with a low baseline diesel efficiency. As mentioned above, many of these low-efficiency diesel refineries are located in California. For example, in the basecase (without GTL diesel penetration), the minimum diesel efficiency in California is 81.7%, while in the 5% GTL diesel penetration case the minimum diesel efficiency in California is 85.2%. In a single California refinery, blending of 5% GTL diesel increased diesel efficiency from 82.3% to 85.3%. The positive diesel efficiency impact of GTL diesel blending appears equally weighted between summer and winter months.

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Analysis shows that relative to the basecase, blending of GTL diesel reduces net hydrogen, fuel gas, and electricity demand associated with diesel production. This impact appears to be nonlinear in relation to the amount of GTL diesel blended. For example, penetration of 5% GTL diesel results in an 11% reduction in fuel gas-related carbon intensity. GTL diesel is an already hydrogen-rich product which allows the refiner to reduce the total severity of hydrotreating to produce diesel. In addition, relative to the basecase, CO_2 emissions resulting from the combustion of FCC coke are reduced with blending of GTL diesel (see SI).

Table 1 (scenario d) illustrates how blending of GTL diesel can potentially increase diesel efficiency by reducing the amount of diesel originating from inefficient pathways within the refinery diesel pool. In this particular example, VGO, which is normally fed into the FCC, is sent to the ULSD hydrotreater and subsequently blended with GTL diesel. Although the input to the FCC is kept full to maintain olefin output for gasoline production, the amount of SR diesel as a share of the total diesel pool is increased relative to the basecase (scenario c). The net result is that the efficiency of diesel pathway 1 increases by approximately 1% due to blending of GTL diesel (scenario d). Note that the example presented here is only one of many possible GTL blending options available to refiners. (The life-cycle GHG emissions of diesel fuel that contains hydrogen-rich blendstocks such as GTL diesel, although out of scope of the current study, would need to include upstream and production-phase emissions of GTL diesel, in addition to reductions in emissions associated with refinery blending. See ref 37 for more details. With the GREET model developed at Argonne National Laboratory, the authors plan to address LCAs of petroleum fuels with different blendstocks in the near future.) It should be stressed that the impacts of GTL blending on refinery and diesel efficiency are presented as an average across 43 U.S. refineries. On an individual refinery basis, depending on constraints, actual results could be higher or lower than what is presented here.

Implications and Impacts Analysis. In this paper, we have applied a method that allows for a more detailed investigation of uncertain refinery parameters that are of key importance to a wide range of stakeholders involved in U.S. energy decisions. The results presented above demonstrate the complex nature of U.S. refinery, product, and unit efficiency analysis. A notable component of this study was the granular level of analysis over 43 large U.S. refineries which allowed for a reliable investigation of key parameters that impact refinery efficiency. Analysis reveals that refinery and product-specific efficiency can vary significantly depending on a number of seasonal and regional factors. Given the variation presented here, these results suggest that average refinery carbon intensity values should not be relied upon for policy implementation.

Processing of incremental amounts of domestic tight oil by U.S. refiners is likely to have a neutral to slightly positive impact on refinery efficiency. Refining of additional amounts of domestic tight light oil could increase crude API gravity, reduce sulfur content, reduce heavy products, and reduce complexity. Linear regression analysis has shown that changes in these parameters would positively impact refinery efficiency. However, in practice, these consequential efficiency impacts on refineries are likely delineated between simple substitution of foreign light sweet crudes and more fundamental changes in refinery configuration to accommodate incremental domestic tight oil. Thus, the financial realities associated with optimal unit operation could result in a rebalancing in crude diet, which in turn could offset the positive impact on efficiency described above.

Diesel efficiency appears to be intimately related to the number and severity of units required to produce diesel. Tighter diesel fuel specifications such as CARB diesel result in a lower diesel efficiency. In the future, if refineries produce incremental diesel through relatively inefficient pathways, diesel efficiency within a refinery would be expected to decrease. This decline in diesel efficiency could be offset by blending of GTL diesel, which could allow refiners to uplift intermediate fuel streams into more efficient diesel production pathways, thereby allowing for the production of incremental barrels of diesel without added capital investment for the refiner. GTL diesel appears to show the greatest synergy with complex refineries that are constrained by tight diesel specifications (e.g., CARB diesel). The relationship between G/D ratio and complexity is currently being investigated further by comparison of the results presented herein with LP modeling results from European refineries[39] that are configured to have a fundamentally different G/D ratio than most U.S. refineries, and these results will be reported shortly.

To conclude, currently U.S. refineries are operated to optimize profit margin. In the context of possible future legislative requirements to reduce CO_2 emissions from refining and to satisfy changes in demand and quality constraints, U.S. refiners may be also be required in the future to optimize for efficiency. The dynamic relationship between efficiency and key parameters such as crude API gravity, sulfur content, heavy products, and refinery complexity are key to understanding any future changes in U.S. refinery efficiency. Given the current wide range of baseline fuel refinery carbon intensity results in public transportation fuel LCA models for refining, this study has shown that the determination of refinery, unit, and product efficiency values requires careful consideration in the context of specific transportation fuel GHG policy objectives.

■ ASSOCIATED CONTENT

Supporting Information

Additional text and figures as mentioned in the text. This material is available free of charge via the Internet at http://pubs.acs.org.

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