A LIFECYCLE ASSESSMENT (LCA) OF NORTH AMERICAN AND IMPORTED CRUDES

FINAL REPORT:

ESTIMATING REFINERY ENERGY CONSUMPTION AND CO_2 EMISSIONS FOR SELECTED CRUDE OILS IN THE U.S. REFINING SECTOR

Prepared for

ALBERTA ENERGY RESEARCH INSTITUTE

By

MathPro Inc.

April 29, 2009

MathPro Inc.

P.O. Box 34404
West Bethesda, Maryland 20827-0404
301-951-9006

TABLE OF CONTENTS

1. INTRODUCTION

The analysis in Task 4 has two objectives:

- Estimate the U.S. refining sector's per-barrel energy use in producing each of the four primary co-products of the refining process: gasoline, jet fuel, diesel fuel and other distillate products (such as heating oil), and all other refined products.

- Estimate the U.S. refining sector's per-barrel energy use and the resulting CO_2 emissions in refining each of thirteen specified crude oils in various U.S. refining regions.

These estimates are intended to support life cycle analysis – sometimes called "well-to-wheels" analysis – of refined product supply pathways by means of LCA models, such as GREET 1.7.[1]

The analysis considered twenty-six (26) crude oil/region combinations, shown in **Exhibit 1.1**.

Exhibit 1.1: Crude Oil / U.S. Refining Region Combinations Analyzed

Origin	Crude Oil	Refining Region PADD 2	 PADD 3	 Calif.
U.S.				
Gulf Coast	West Texas Inter. (WTI)	x	x	
California	SJV Heavy			x
Alaska	ANS			x
Imports (ex Canada)				
Saudi Arabia	Saudi Medium	x	x	x
Iraq	Basrah Medium		x	x
Nigeria	Escravos		x	
Venezuela	Bachaquero 17		x	
Mexico	Maya		x	x
Canada				
Conventional Heavy	Bow River	x		
SCO	SCO (*mined bitumen)*	x	x	x
SCO	SCO *(in situ bitumen)*	x	x	x
Synbit	SCO / in situ bitumen	x	x	x
Dilbit	Conden. / in situ bitumen	x	x	x

---

[1] *Operating Manual for GREET: Version 1.7*; Center for Transportation Research, Argonne National Laboratory; ANL/ESD/05-3; February 2007; http://www.transportation.anl.gov/modeling_simulation/GREET/publications.html#intro

The eight U.S. and imported (ex Canada) crude oils, along with Bow River crude, are large-volume, conventional crudes ranging in quality from light, low-sulfur (WTI, Escravos) to very heavy, high-sulfur (SJV Heavy, Maya). The Canadian crudes (ex Bow River) are representative of the crudes being produced from Alberta oil sands and entering U.S. markets in increasing volumes. The refining regions associated with each crude oil are those to which the crude oil now flows and those to which it would likely flow in the future. For example, future volumes of the oil sands crudes would most likely go to PADD 2 (the Midwest), PADD 3 (the Gulf Coast), and California, for economic and logistical reasons.[2]

We developed estimates of refinery energy use by means of detailed, process-oriented modeling of regional refining operations. In particular, we used linear programming (LP) modeling, implemented in MathPro's proprietary refinery modeling system (called **ARMS**), to develop and operate a *national* U.S. refining model and three *regional* refining models.

The national model represents aggregate refining capacity and refining operations in the U.S. in 2006. We used the this model to estimate the refining sector's per-barrel energy use attributable to the production of gasoline, jet fuel, diesel fuel and other distillate products, and all other refined products.

Each regional model represents aggregate refining capacity in one of the regions of interest, processing a mixed crude oil slate and producing a slate of refined products meeting all U.S. specifications and regulatory requirements. We used the regional models to estimate refinery energy use and resulting CO_2 emissions associated with processing the various crude oils in the specified refining regions combination.

This report discusses the technical foundation, methodology, and results of Task 4 and comprises eight sections, including this one.

1. Introduction
2. Essentials of crude oils, refining, and refinery energy use
3. Crude oil assays used in the analysis
4. Energy use in U.S. refineries
5. The refinery energy and CO_2 accounting framework used in the analysis
6. Overview of the analytical approach
7. Key results and findings
8. Comments on the results

---

[2] Some Alberta crude oil flows to U.S. PADD 4 (the Mountain states) and that volume is likely to increase. We did not consider PADD 4 in this analysis because it is small, accounting for less than 4% of U.S. refining capacity.

2. SOME ESSENTIALS OF CRUDE OIL CHARACTERIZATION, REFINING, AND REFINERY ENERGY USE

To facilitate the subsequent discussion of the technical approach and results of Task 4, this section offers an overview of basic concepts regarding crude oils, refining operations, and refinery energy use. Detailed discussion of refining operations in general and the U.S. refining sector in particular is well beyond the scope of this study.[3]

2.1 Crude Oil and Its Constituents

Hundreds of crude oils (usually identified by geographic origin) are processed, in greater or lesser volumes, in the world's refineries. Each crude oil is a unique mixture of thousands of compounds, mainly hydrocarbons.[4] Some hydrocarbon compounds contain small (but important) amounts of other ("hetero"-) elements, most notably sulfur, nitrogen, and certain metals (e.g., nickel, vanadium, etc.). The compounds that make up crude oil range from the smallest and simplest hydrocarbon molecule – CH_4 (methane) – to large, complex molecules containing up to 50 or more carbon atoms (as well hydrogen and hetero-elements).

In general, the more carbon atoms in a hydrocarbon molecule, the heavier and more dense the material and the higher the boiling temperature.[5] This characteristic of hydrocarbons enables the separation of crude oils into distinct boiling range constituents, or fractions, by *distillation* (or *fractionation*), a standard refining process that is the starting point for all other refining processes and operations.

The physical and chemical properties of any given crude oil fraction or refinery-produced stream depends on the molecular composition of the stream – not only the number of carbon atoms in each component but also the nature of the chemical bonds between them. Carbon atoms readily bond with one another (and with hydrogen and hetero-atoms) in various ways – single bonds, double bonds, and triple bonds – to form different classes of hydrocarbons, as illustrated in **Exhibit 2.1** Paraffins, aromatics, and naphthenes are natural constituents of crude oil; but are produced in various refining operations as well. Olefins are not present in crude oil; they are produced in certain refining operations dedicated mainly to gasoline production.

The proportions of these hydrocarbon classes, their carbon number distribution, and the concentration of hetero-elements in a given crude oil influence the yields and qualities of the refined products that a given refinery can produce from that crude, and hence the economic value of the crude.

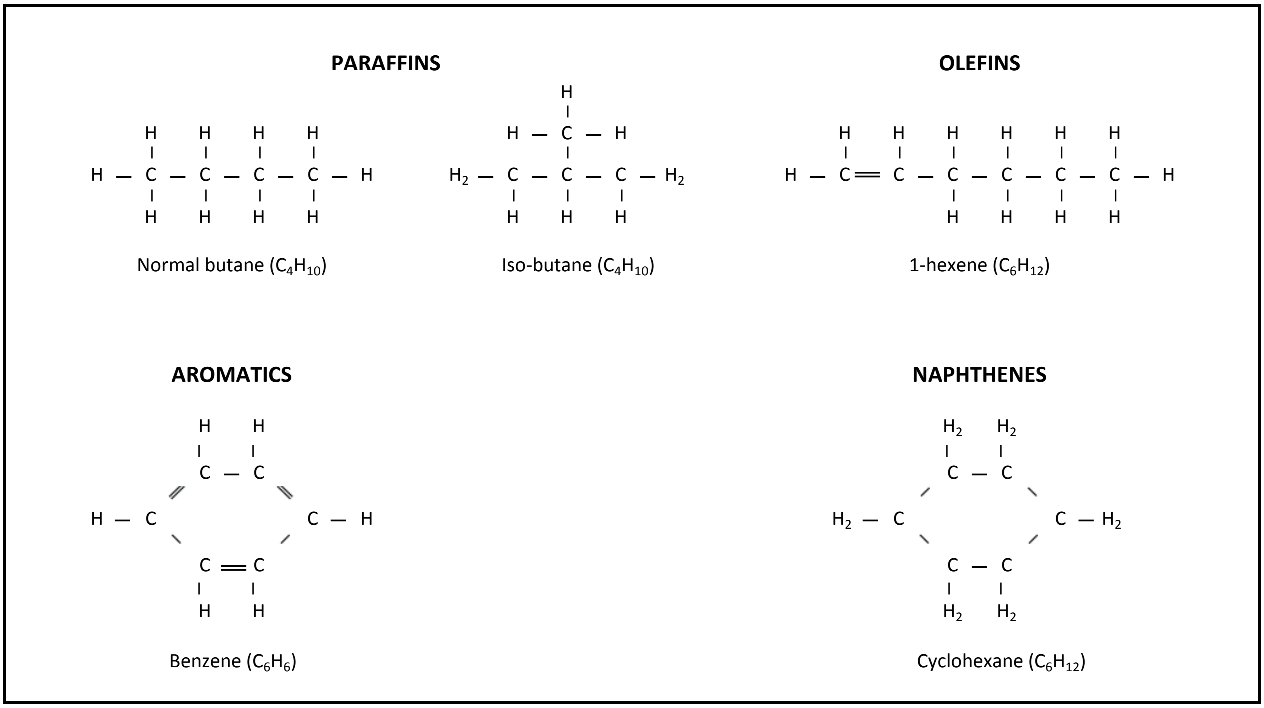
---

[3] For a particularly useful discussion of the fundamentals of refining operations in the U.S. refining sector, see Appendix C of "U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels"; June 2000; National Petroleum Council; www.npc.org

[4] Hydrocarbons are organic compounds composed of carbon and hydrogen.

[5] Gasoline, for example, consists of molecules in the C_4–C_{12} range, and has a boiling range of ≈ 60^o–375^oF; diesel fuel consists of molecules in the C_{15}–C_{20} range, and has a boiling range of ≈ 425^o–625^oF.

Exhibit 2.1: Important Classes of Hydrocarbon Compounds in Refining



Normal butane (C_4H_{10})

Iso-butane (C_4H_{10})

1-hexene (C_6H_{12})

Benzene (C_6H_6)

Cyclohexane (C_6H_{12})

For example, the volume of gasoline that a given refinery can produce depends in part on the fraction of the crude oil that is in the gasoline boiling range. In that boiling range, aromatic and naphthenic compounds contribute more octane to the gasoline pool than do paraffinic compounds. (In the U.S., refiners must control the aromatics content of gasoline in order to meet emissions standards.) In the distillate (jet fuel and diesel fuel) boiling range, aromatics content adversely affects product quality (cetane number, smoke point); hence, the processing severity required to meet jet fuel and diesel fuel specifications increases with the aromatics content of the crude fractions in the distillate boiling range.

As Figure 2.1 indicates, aromatic compounds have higher carbon-to-hydrogen ratios than paraffins and naphthenes. Due to the chemistry of oil refining, the higher the aromatics content of a crude oil, the higher the coke[6] yield and the more hydrogen is required in the refining process (all else equal). Through mechanisms such as these, the chemical make-up of a crude oil and its various boiling range fractions influence refinery energy use and the CO_2 emissions associated with refining the crude to produce a given slate of refined products.

2.2 Crude Oil Characterization

---

[6] Petroleum coke is ≈ 95 wt% carbon.

A *crude oil assay* is a detailed characterization of the chemical and physical properties of a crude oil and its boiling range fractions, developed from an extensive set of analyses performed by petroleum testing laboratories. A crude assay includes a characterization of the crude oil as a whole and more detailed characterizations of each boiling range fraction. Every crude oil has a unique assay; no two are the same.[7]

Detailed assays for all crudes in commerce are maintained in proprietary assay libraries. Many assays are placed in the public domain, in varying levels of detail and varying vintage. For many crudes – particularly those that have been in commerce for some time – assays of recent vintage and sufficient detail for most analytical purposes are available in the public domain.

Exhibit 2.2 shows an extract of the physical and chemical properties reported in a typical crude assay. The properties shown in Exhibit 2.2 are those that we usually use in assessing the economic values of crude oils.

Crude assay yields – the volumetric yields of the various crude oil fractions – often are presented graphically as a *crude oil distillation curve*, a plot of cumulative volume distilled off as a function of boiling temperature.

The indicated properties of the whole crude – API gravity (a common industry measure of density) and sulfur content – are widely used to classify crude oils as heavy, medium, or light (denoting specific gravity) and as sweet or sour (denoting sulfur content). All else equal, light crudes yield higher proportions of the more valuable light products (gasoline, jet fuel, diesel fuel); sweet crudes tend to incur lower refining costs than sour crudes of the same density (because of the costs associated with removing sulfur from refined products and refinery effluents to meet environmental standards).

The most common crude oil classifications are:

- Synthetic crude oil (SCO), such as that produced by upgrading Alberta bitumens
- Light sweet crude
- Light sour crude
- Medium sweet crude
- Medium sour crude
- Heavy sour crude

However, simple classifications based on properties of the whole crude are insufficient for assessing the refining economics of crude oils or estimating the refinery energy required to process crude oils. For these tasks, techno-economic assessments of crude oils are based on the volumes and properties (such as those shown in Exhibit 2.2) of their various boiling range fractions. The volumetric yields and the properties of the crude oil fractions exert significant influence on crude oil values, refining operations, and refinery energy use.

---

[7] The assay for a given crude may change over time as a result of changes in the method used to produce the crude from its reservoir, changes in analytical procedures, or unintended commingling with other crude oils.

Exhibit 2.2: Representative Subset of Crude Oil Properties Provided in a Crude Assay

		Boiling	Physical Property							
		Range	Yield	RON	N + 2A	Sulfur	Cetane No	Sp. Grav	K Factor	Con Carb.
Crude Oil Fraction		(°F)	(vol%)		(vol%)	(ppmw)		(° API)		
	Notes	----->	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Whole crude						✔		✔		
Light ends		C_4^-	✔							
Naphtha	Straight run	C5-160	✔	✔				✔		
	Light	160-250	✔		✔			✔		
	Medium	250-325	✔		✔			✔		
	Heavy	325-375	✔		✔			✔		
Distillate	Kerosene	375-500	✔			✔		✔		
	Diesel	500-620	✔			✔	✔	✔		
Vacuum gas oil	Light	620-800	✔			✔		✔	✔	
	Heavy	800-1050	✔			✔		✔	✔	
Vacuum resid	Residual oil	1050+	✔			✔		✔		✔

Notes:

1 **Yield** is the volume percent of the whole crude in the indicated boiling range.
2 **RON** is Research Octane Number, a standard measure of anti-knock quality.
3 **N + 2A**, an indicator of reformer feed quality, is the vol. % Naphthenes plus 2 x the vol % Aromatics in the naphtha.
4 **Sulfur** is the sulfur content of the fraction, in weight parts per million or in weight %.,
5 **Cetane** is Cetane Number, a measure of diesel fuel performance.
6 **Sp Grav** is the specific gravity, or density, of the crude fraction, usually expressed in *API degrees* . (^{o} API = (141.5/Sp.Gr.) - 131.5).
7 **K Factor** is the Characterization, a function of the crude fraction's specific gravity and distillation curve, is an indicator of the gas oil's susceptibility to cracking.
8 **Con Carbon** is Conradson Carbon, an indicator of the coke yield of the crude fraction when it is subjected to cat cracking or coking.

2.3 U.S. Refining Operations

Petroleum refineries are large, complex, continuous-flow plants that process crude oils and other input streams into a large number of refined (co-)products, most notably LPG, gasoline, jet fuel, diesel fuel, petrochemical feedstocks, home heating oil, fuel oil, and asphalt. Each refinery has a unique configuration and operating characteristics, determined primarily by its location, vintage, preferred crude oil slate, and market requirements for refined products.

The U.S. refining sector is the world's largest. It produces mainly high-value, "light" products – primarily transportation fuels (gasoline, jet fuel, diesel fuel) and petrochemical feedstocks – that meet stringent U.S. performance specifications and environmental standards. U.S. refineries are among the world's most complex and technically advanced, embodying extensive processing and upgrading of crude oil fractions and "conversion" of the heaviest crude oil fractions into lighter, higher-valued products (mainly transportation fuels).

Virtually all U.S. refineries process multiple crude oils simultaneously. Some refineries are designed to process mostly light, low-sulfur (sweet) crudes; others are configured and equipped to process heavy, high sulfur (sour) crudes. Heavy, sour crudes are more difficult to process into transportation fuels, but consequently are less expensive than light, sweet crudes.

Almost all U.S. refineries are either *conversion* ("cracking") or *deep conversion* ("coking/ cracking") refineries, designed to maximize production of light products (mainly transportation fuels) by converting ("cracking") the high boiling range fractions of the crudes to lighter fractions in the gasoline and diesel fuel boiling ranges. Conversion refineries convert vacuum gas oils into lighter products; deep conversion refineries convert not only vacuum gas oils but also vacuum resid, the heaviest crude fraction, into lighter products.

Exhibit 2.3 is a highly simplified flow chart of a notional U.S. deep conversion refinery, illustrating a typical flow pattern of crude oil fractions from the crude oil distillation units to the various downstream processing units and ultimately to product blending. Vacuum resid, the heaviest product of vacuum distillation, goes to the coker (in a deep conversion refinery), where it is converted (cracked) to lighter streams for further processing to higher-valued products, or (in a conversion refinery) to the refinery's residual oil or asphalt product pool (low value). The other products of vacuum distillation, the vacuum gas oil fractions, go to the fluid cat cracking (FCC) unit and/or to the hydrocracker, where they are cracked to lighter streams that ultimately find their way into the gasoline and distillate product pools. In many conversion refineries, vacuum gas oils fed to the FCC unit go first to an FCC feed hydrotreater, which removes sulfur and other impurities and increases the hydrogen content of the FCC feed (which in turn increases the FCC's gasoline yield).

Straight run distillate, the heaviest product of atmospheric distillation, goes either to hydrotreating and then blending to distillate products (e.g., diesel fuel) or to hydrocracking, where it is converted to gasoline and jet fuel blendstocks. Straight run kerosene, the next lighter product of atmospheric distillation, goes to hydrotreating and then blending to kerosene and jet or diesel fuel products. Finally, the straight run naphthas go to various processes in which they are treated and upgraded for gasoline blending or (for the heaviest naphthas) jet fuel blending.

For purposes of this discussion, the important aspect of Exhibit 2.3 is not any of its details, but the overall picture it conveys of the complexity of refining operations in general and U.S. refining in particular. As the flow chart suggests, U.S. refineries comprise many specialized refining processes. However, these processes can be thought of in terms of a few broad classes, shown in **Exhibit 2.4**.

Exhibit 2.3: Simplified Flow Chart of a U.S. Deep Conversion Refinery

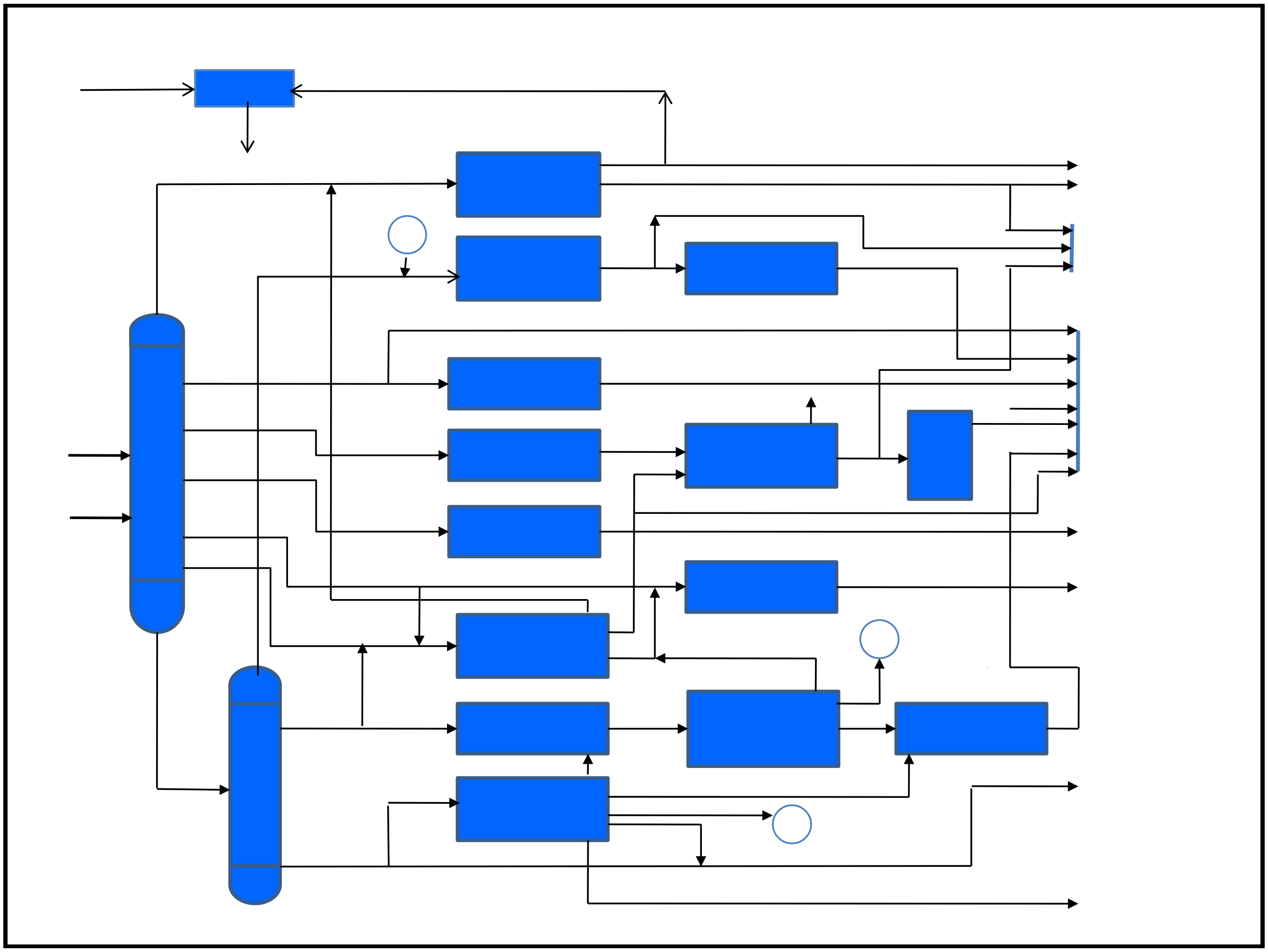


Exhibit 2.4: Important Classes of Refining Processes in U.S. Refineries

Class	Function	Examples
Crude distillation	Separate crude oil charge into boiling range fractions for further processing	Atmospheric distillation Vacuum distillation
Conversion	Break down ("crack") heavy crude fractions into lighter, higher-valued streams for further processing	Fluid cat cracking Coking, Hydrocracking
Upgrading	Enhance the blending properties (e.g., octane) and value of gasoline and diesel blendstocks	Reforming Alkylation, Isomerization
Treating	Remove hetero-atom impurities from refinery streams and blendstocks	Hydrotreating Caustic treating
Separation	Separate, by physical or chemical means, constituents of refinery streams for further processing	Fractionation Extraction
Blending	Combine blendstocks to produce finished products that meet product specifications and environmental standards	
Utilities	Supply refinery fuel, power, steam, oil movements, storage, emissions control, etc.	Power generation Sulfur recovery

Exhibits 2.3 and 2.4 illustrate three aspects of refining operations that merit comment in the context of this study.

- Refinery operations are extremely complex.

  Exhibit 2.3 only hints at the actual complexity of a conversion refinery – with respect to the physical facilities of the refinery, the interaction of these facilities with one another, and the range of operations of which they are capable.

- Refineries produce a wide range (or “slate”) of products – actually co-products.

  The light products are more valuable than the other products (residual oil, asphalt, etc.). Hence, in general, U.S. conversion refineries seek to maximize production of light products, to the extent their process capabilities allow. Refineries have some ability to change their product slate in response to market conditions and to maintain their product slate in the face of changes in the slate of crude oils that they process. This flexibility is centered in the refineries' conversion units, which convert vacuum gas oil and resid fractions into lighter fractions that can be upgraded and blended into gasoline, jet fuel, and diesel fuels.

Refiners can change the operations of their conversion units to accommodate changes in crude and product slates, but only within physical limits defined by the characteristics of these units and the properties of the crude oils. To exceed these limits requires capital investment in new or expanded process capacity. For example, a U.S. refinery may have to install coking capacity and additional FCC capacity to accommodate Canadian dilbits in its crude slate.

- Refinery energy use is (1) distributed, not concentrated, and (2) increases with increasing refining severity.[8]

  Essentially all refining processes consume energy, primarily in the form of process heat (from the combustion of natural gas and various refinery-generated fuels) and electricity. A few processes are net producers of energy, primarily in the form of steam generated from process waste heat.[9]

  In general, the severity of refining operations needed to produce a given product slate is a function of the physical and chemical properties of the crude oil slate (as discussed below) and the design of the refinery's conversion and upgrading processes.

2.4 Crude Oil Properties and Their Effect on Refining Operations

The various properties of a crude oil affect the operations and performance of any given refinery, and indeed determine the technical and economic feasibility of running the crude in that refinery. Some of the manifold ways in which crude oil properties affect operations in a U.S. light products refinery are listed below (with reference to Exhibits 2.3 and 2.4):

- The volumetric **yields** of the various crude fractions determine the relative feed rates to the primary refinery process units and the amount of conversion and treating capacity needed to produce the required volumes of light products;

- The **RON** and **N + 2A** content of the naphtha streams influence the extent and severity of upgrading process operations (primarily reforming) needed to meet gasoline volume and octane requirements;

---

[8] "Severity" is a term of art denoting the thermodynamic intensity of refinery processing. For example, a refiner might increase the severity of a refinery process by increasing the temperature at which the process operates, so as to accelerate a chemical reaction.

[9] In addition, many refineries have co-generation units, which produce electricity and steam for process heat. Some refineries sell a portion of their co-generated electricity to the local grid.

- The volumetric **yield** and the **vapor pressure** (not shown in Exhibit 2.2) of the light straight run naphtha influences the extent of the separation (fractionation) operations required to meet industry and regulatory standards for gasoline volatility.

- The **Sulfur** levels of the various crude fractions determine the required treating capacity for desulfurization, the severity and cost of these operations, and the associated hydrogen consumption;

- The **Con Carbon** content and **K Factor** of the heavy crude fractions are indicators of the carbon/hydrogen ratio and the aromatics content in these fractions.

  The carbon/hydrogen ratio of a crude fraction or refinery stream determines the extent to which these fractions can be converted to lighter components in the **Conversion** processes; the volumes of petroleum coke and catalyst coke produced in coking and cat cracking, respectively; the yield patterns in coking and cat cracking and coking; refinery hydrogen consumption; the aromatics content of the various light products; and the throughput capacity of given process units.

  For example, the yield of gasoline blendstocks in cat cracking and coking is a strong increasing function of the hydrogen content of the feed.

Crude oil properties affect refining operations and performance in many other ways as well, too numerous to mention here. They also determine in large measure the design and materials of construction of the various process units.

2.5 Crude Oil Properties and Their Effects on Refinery Energy Use and CO_2 Emissions

The conversion of crude oil into refined products in a refinery requires the expenditure of energy, which is provided in U.S. refineries by the combustion of natural gas and of by-product streams (primarily catalyst coke and still gas) produced in the refinery and by electricity (either purchased or produced in the refinery by co-generation units fueled by natural gas). Because crude oil properties affect the nature and severity of refinery operations, they also affect refinery energy use and the consequent CO_2 emissions.

2.5.1 Effects on Refinery Energy Use

- The crude distillation curve has two primary effects on refinery energy use.

  - Crude distillation (**Atmospheric Distillation** and V**acuum Distillation** in Exhibit 2.3) – which separates the crude oil charge into its boiling range fractions – is the most energy-intensive refining process. In general, the lighter the crude oil (i.e., the greater the proportion of low-boiling fractions: distillates and lighter), the higher the energy (fuel) use in crude distillation.

Alone among crude oils, synthetic crude oil (SCO) contains essentially no vacuum resid (boiling range: 1050^o F +). Vacuum resid is separated from the next lightest fractions, the light and heavy vacuum gas oils, in the **Vacuum Distillation** unit. Hence, if SCO is segregated from conventional crudes in shipment and in crude distillation (as we assume in this study), it incurs no energy expenditure for vacuum distillation.

- The heavier the crude oil the higher the volumetric yields of vacuum gas oil and resid fractions, the higher the through-put and/or the operating severity in the conversion units (cat cracking (FCC), coking, and hydrocracking) needed to produce a given product slate, and hence the higher the refinery energy consumption.

  The conversion units all consume energy directly. Hydrocracking also consumes energy indirectly, due to its requirements for large volumes of hydrogen. (Hydrogen production is highly energy-intensive).

- The higher the sulfur content (and hetero-atom content) of the various crude fractions, the higher the refinery energy use.

  - Essentially all of the sulfur, except that in the heaviest fraction (vacuum resid) must be removed, primarily by FCC feed hydrotreating, product hydrotreating, and hydrocracking.

  - Essentially all hetero-molecules (which poison process catalysts) in heavy naphtha, distillates, and vacuum gas oil must be removed by hydrotreating: FCC feed hydrotreating and naphtha hydrotreating.

  Hydrotreating and hydrocracking use energy both directly and indirectly, in quantities that increase with increasing sulfur and hetero-molecule content. The indirect energy use is primarily in hydrogen production.

  For example, the sulfur content of FCC products – which constitute large fractions of the gasoline and diesel fuel pools – is directly correlated with the sulfur content of the FCC feed. FCC feed hydrotreating and hydrocracking, processes needed for meeting stringent U.S. specifications on gasoline and diesel fuel sulfur content, are two of the largest energy consumers in U.S. refineries.

- The chemical composition (such as aromatics content, hetero-atom content) and properties of crude oil fractions fed to the conversion units, as well as to the upgrading units (such as reforming) and treating units (naphtha hydrotreating, distillate hydrotreating), influence the product yields and the required operating severity in the various refinery units that process the crude oil fractions.

  For example, in cat cracking, conversion and gasoline yield tend to decrease with increasing aromatics content and sulfur content in the cat cracking feed (all else equal). Cat crackers and cokers "over-crack" some feed material (that is, reduce it to coke and light-gas by-products), and over-cracking increases with increasing severity. Hydrocrackers consume hydrogen, in amounts that increase with increasing severity.

Refinery energy use in these units increases with increasing severity because:

- Increasing severity usually means higher operating temperatures and/or pressures, achievement of which calls for additional energy.
- Increasing severity entails some loss in product yield (with a corresponding increase in low-valued by-product yield), meaning that the refinery must process more crude oil and expend more energy to produce a given product slate.

Each crude oil has a unique set of properties. Hence, energy use in any given refinery is a function of the refinery's crude oil slate (all else equal).

2.5.2 Effects on Refinery CO_2 Emissions

Refinery CO_2 emissions are primarily a consequence of refinery energy use. The volumetric yields and properties of a crude oil's fractions affect refinery energy use because influence the extent of processing they partially determine the operating severity needed in various process units to meet product volume and quality requirements.

The sources of energy used in the refinery (natural gas, still gas, FCC catalyst coke, electricity) also influence CO_2 emissions to some extent. Refineries that rely most on the more-carbon-intensive sources (catalyst coke, coal-sourced electricity) will tend to have higher CO_2 emissions per barrel of crude throughput than refineries that rely more on less-carbon-intensive sources (natural gas, still gas, natural gas- or nuclear-sourced electricity).

3. ASSAY PROPERTIES OF THE CRUDE OILS CONSIDERED IN THE ANALYSIS

3.1 Sources of the Crude Oil Assays

We used assays in MathPro's library for the three U.S. crudes and the five Import crudes. These assays come from public and private sources. We updated three of these assays – for ANS, SJV Heavy, and Bow River – in the course of this study.

We developed assay data for the four Canadian bitumen crudes (Exhibit 1.1) from bitumen and dilbit assays obtained in the course of this study from industry sources.

The assay for *SCO from mined bitumen* is a composite assay representing SCOs produced by Syncrude Canada and Suncor; we prepared the composite assay from individual assays provided by the companies.

The assay for *SCO from in situ bitumen* represents Long Lake SCO and was provided by its producer, OPTI/Nexen.[10]

The assay for *Dilbit* (25% condensate/75% in situ bitumen) represents Cold Lake Dilbit and was provided by its producer, ExxonMobil Canada.

We had no assay for *Synbit* (50% SCO/50% in situ bitumen) so we derived one, starting from the Cold Lake Dilbit assay. First, we estimated assay properties for the bitumen by a volume-weighted "subtraction" of 25 vol% diluent from the Dilbit assay. Then, we combined the derived bitumen assay with the composite assay for SCO from mined bitumen, on a 50/50 volume-weighted basis, to obtain the Synbit assay.

3.2 Properties of the Whole Crudes and Boiling Range Fractions

Exhibit 3.1 shows the API gravity, sulfur content, and classification of the thirteen crude oils considered in this study.

As the exhibit indicates, the U.S. and imported (ex Canada) crude oils span the range from light sweet to heavy sour; Bow River, Synbit, and Dilbit are heavy sour crudes. Collectively, the crude oils are reasonably representative of the larger set of conventional crude oils processed by U.S. refineries. The aggregate crude slate processed by the U.S. refining sector has an average API gravity of about 30.4^o and average sulfur content of about 1.4 wt%.[11]

---

[10] OPTI/Nexen considers the Long Lake assay to be confidential. Hence, the exhibits show minimal assay information for the SCO from in situ bitumen.

[11] The aggregate U.S. crude slate is growing gradually heavier and higher in sulfur. This trend has persisted over many years.

Exhibit 3.1: API Gravity and Sulfur Content of the Study's Crude Oils

Crude Oil	API Gravity (°)	Sulfur Content (wt%)	Classification
U.S.			
West Texas Inter. (WTI)	39.6	0.49	Light sweet
SJV Heavy	13.6	1.38	Heavy sour
ANS	32.0	0.90	Medium sweet
Imports (ex Canada)			
Saudi Medium	30.3	2.57	Medium sour
Basrah Medium	31.0	2.58	Medium sour
Escravos	35.3	0.16	Light sweet
Bachaquero 17	16.7	2.40	Heavy sour
Maya	21.1	3.38	Heavy sour
Canada			
Bow River	20.7	2.85	Heavy sour
SCO (*mined bitumen)*	32.2	0.16	Synthetic crude
SCO *(in situ bitumen)*	39.4	0.001	Synthetic crude
Synbit	21.0	2.53	Heavy sour
Dilbit	21.2	3.69	Heavy sour

Exhibit 3.2 shows in tabular form each crude oil's volumetric yields of the various boiling range fractions.

Exhibits 3.3a, 3.3b, and 3.3c show the distillation curves for the U.S., imported, and Canadian crudes, respectively. The distillation curves are graphs of the boiling range yields tabulated in Exhibit 3.2.

Exhibit 3.4 shows some key properties of the various boiling range fractions for each crude oil.[12] The properties shown in Exhibit 3.4 are all incorporated in the regional refining models used in the study.

---

[12] These properties correspond to those indicated in Exhibit 2.2.

Exhibit 3.2: Crude Oil API Gravity, Sulfur Content, and Boiling Range Yields

			U.S. Crudes			Imported Crudes					Canadian Crudes				
		Boiling Range (°F)	West Texas Inter	SJV Heavy	Alaskan North Slope	Saudi Medium	Iraq Basrah Medium	Nigerian Escravos	Venez. Bach 17	Mexican Maya	Bow River	Mining SCO	In Situ SCO	Synbit	Dilbit with Diluent
Whole Crude	API Gravity		39.6	13.6	32.0	30.3	31.0	35.3	16.7	21.1	20.7	32.2	39.4	21.0	21.2
	Sulfur (wt%)		0.49	1.38	0.90	2.57	2.58	0.16	2.40	3.38	2.85	0.16	0.00	2.53	3.69
Gases	C3-		0.5	0.0	0.4	0.7	0.7	0.4	0.3	0.0	0.1	0.1		0.1	0.0
	C4		1.6	0.0	3.1	2.0	1.5	1.2	0.5	0.0	1.0	1.9		0.9	0.9
Naphthas	Straight Run	C5-160	6.0	0.0	5.2	4.8	5.4	4.5	1.8	3.2	4.5	5.1		2.6	13.4
	Light	160-250	11.6	0.3	8.5	7.1	7.8	8.1	2.3	5.3	4.0	6.0		3.1	5.5
	Medium	250-325	9.8	0.7	9.2	6.9	6.9	7.8	2.6	5.0	3.5	5.6		2.9	3.0
	Heavy	325-375	5.6	1.1	4.3	4.9	4.6	8.8	2.0	3.5	3.1	3.8		2.0	1.5
Distillate	Kerosene	375-500	13.7	7.5	11.0	11.3	11.5	17.1	6.7	10.0	9.7	12.0		8.6	5.0
	Diesel	500-620	12.2	11.9	11.5	10.9	11.3	15.1	10.4	9.3	9.2	19.7		15.0	8.0
Vacuum Gas Oil	Light	620-800	15.5	21.9	15.5	14.3	15.1	18.2	18.1	13.2	13.9	29.7		22.8	12.0
	Heavy	800-1050	14.3	26.2	16.5	16.1	16.1	13.0	22.5	16.5	19.8	16.3		19.4	16.9
Vacuum Resid	Residual Oil	1050+	9.2	30.5	14.8	20.8	19.1	5.7	32.8	34.0	31.1	0.0		22.5	33.8
Total			100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Exhibit 3.3a: Distillation Curves for U.S. Crudes

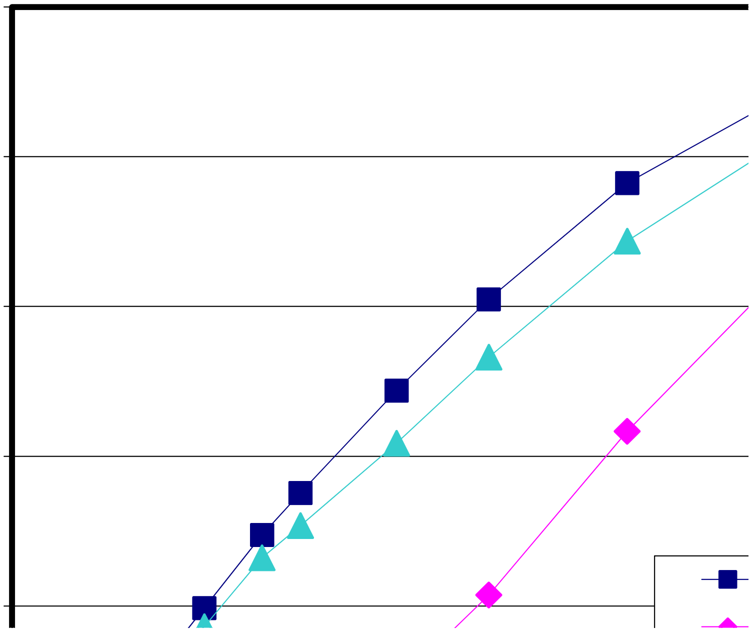


Exhibit 3.3b: Distillation Curves for Imported Crudes

Exhibit 3.3c: Distillation Curves for Canadian Crudes

Exhibit 3.4: Key Properties of Crude Oil Boiling Range Fractions

			U.S. Crudes			Imported Crudes					Canadian Crudes				
		Boiling Range (°F)	**West Texas Inter**	**SJV Heavy**	**Alaskan North Slope**	**Saudi Medium**	**Iraq Basrah Medium**	**Nigerian Escravos**	**Venez. Bach 17**	**Mexican Maya**	**Bow River**	**Mining SCO**	**In Situ SCO**	**Synbit**	**Dilbit with Diluent**
Whole Crude	API Gravity		39.6	13.6	32.0	30.3	31.0	35.3	16.7	21.1	20.7	32.2	39.4	21.0	21.2
	Sulfur (wt%)		0.49	1.38	0.90	2.57	2.58	0.16	2.40	3.38	2.85	0.16	0.00	2.53	3.69
Napthas	Straight Run	C5-160													
	RON		65.6	75.5	69.0	70.5	66.7	78.5	73.6	63.7	73.1	73.4		73.4	71.9
	Light	160-250													
	N + 2A (vol%)		61.2	72.0	59.0	25.4	31.7	90.0	83.5	42.0	43.7	46.5		45.5	60.1
	Medium	250-325													
	N + 2A (vol%)		66.4	82.0	75.6	45.3	46.6	77.0	87.7	55.0	70.6	71.9		71.3	74.3
	Heavy	325-375													
	N + 2A (vol%)		65.9	79.0	79.0	64.8	63.1	65.5	87.6	66.4	71.2	93.6		93.3	72.9
Distillate	Kerosene	375-500													
	Sulfur (ppm)		1,800	3,300	1,100	3,200	3,700	600	4,700	10,000	7,000	200		4,200	10,620
	Cetane No.		46.8	33.0	41.5	49.0	47.9	40.0	37.5	46.0	40.2	35.0		32.4	27.8
	Diesel	500-620													
	API Gravity		36.6	25.0	31.0	35.2	35.1	32.3	28.3	33.0	27.0	27.7		27.4	27.2
	Sulfur (ppm)		3,400	7,200	5,000	13,900	15,800	1,100	10,600	21,000	15,000	700		7,300	19,000
	Cetane No.		56.7	32.0	46.0	51.2	40.1	49.7	43.1	47.0	43.1	38.8		36.4	33.2
Vacuum Gas Oil	Light	620-800													
	API Gravity		30.6	18.2	24.0	26.5	26.0	27.6	20.0	25.5	21.0	21.6		20.9	19.6
	Sulfur (ppm)		5,700	11,700	10,500	25,500	23,700	2,300	20,400	28,000	21,000	2,500		11,000	26,550
	K factor		12.1	11.2	11.6	11.8	11.7	11.8	11.3	11.7	11.4	11.4		11.4	11.3
	Heavy	800-1050													
	API Gravity		22.2	12.2	17.5	19.1	15.6	17.2	15.5	17.5	13.5	16.4		13.9	12.1
	Sulfur (ppm)		8,400	15,200	13,500	31,900	38,100	4,200	25,200	36,000	31,000	3,800		26,900	43,140
	K factor		12.1	11.3	11.7	11.9	11.6	11.7	11.6	11.6	11.4	11.6		11.5	11.3
Vacuum Resid	Residual Oil	1050+													
	API Gravity		13.3	1.0	5.5	4.1	4.1	10.1	2.6	-1.4	3.0			2.0	2.0
	Sulfur (ppm)		13,300	18,800	23,500	53,500	57,200	5,500	36,600	54,000	49,000			61,000	61,000
	Con Carbon (wt%)		14.0	22.3	22.0	25.1	26.1	17.0	26.6	31.4	25.0			26.2	26.2
Utilities Used in	Fuel Use (foeb/b)		0.016	0.013	0.015	0.014	0.014	0.016	0.012	0.012	0.012	0.010	0.012	0.014	0.012
Crude Distillat'n	Steam (lbs/b)		34.2	31.2	33.3	32.2	32.6	34.8	30.6	30.0	30.6	18.7	24.2	32.4	30.0
	Power (kWh/b)		0.82	0.94	0.84	0.85	0.85	0.81	0.92	0.89	0.89	0.70	0.70	0.89	0.89

3.3 Observations on Crude Properties and Refining Operations

The U.S. and imported crudes have *vacuum resid* (coker feed) yields ranging from about 9 vol% to more than 34 vol%. Synbit and Dilbit have vacuum resid yields of about 22 vol% and 34% vol%, respectively. SCOs contain no vacuum resid by virtue of the field upgrading processes that produce them.

Most of the U.S. and imported crudes have *vacuum gas oil* (FCC feed) yields in the range of about 30 vol%, with a few heavy outliers (e.g., SJV Heavy, Maya), which have yields of 40 vol% and higher. Dilbit has a vacuum gas oil yield in the 30 vol% range. Synbit and straight SCO have unusually high vacuum gas oil yields – well above 40 vol%.

> (As Exhibit 2.3 indicates, vacuum resid goes either to the coker, where it is converted (cracked) to lighter streams for further processing to higher-valued products, or else to the refinery's residual oil product pool (low value). Vacuum gas oil goes to the FCC unit (which in many refineries is preceded by an FCC feed hydrotreater) and to the hydrocracker, in both of which it is converted to lighter streams processed into gasoline and diesel blend stocks.)

Some crude oils – including Dilbit, Synbit, and SCO – are high in aromatics content.[13] All else equal, high aromatics content has adverse effects on the quality of jet fuel and diesel fuel. Counteracting these effects requires more severe hydrotreating and increased hydrogen consumption. SCO vacuum gas oil is very low in sulfur and hence does not require FCC feed hydrotreating before going to the FCC unit. SCO offers higher-than-average yields of vacuum gas oil. However, taking advantage of these SCO characteristics requires segregating the SCOs from the conventional crude oils. Some refineries are configured so as to be able to segregate different crude types; others are not.

As these comments suggest, the properties of Dilbit, Synbit, and SCO affect their disposition in the U.S. refining sector and their refinery energy use. Dilbit is suitable for many U.S. deep conversion refineries – having both a coker and an FCC unit – because Dilbit has vacuum resid and vacuum gas oil fractions with yields comparable to the U.S. average. Straight SCO (uncontaminated by conventional crude oil or bitumen) is best suited for processing in conversion refineries – having an FCC unit but no coker – because SCO contains no vacuum resid. For the same reason, SCO does not require processing in the refinery's vacuum distillation unit (which separates vacuum resid from vacuum gas oil, as indicated in Exhibit 2.3).

---

[13] A good indicator of a crude's aromatics is the **K factor** of the vacuum gas oil (Exhibit 3.4). Aromatics content is inversely related to K factor. A K factor in the range of (≈ 11.2–11.5 indicates high aromatic content.

4. ENERGY USE IN U.S. REFINERIES

U.S. refineries account for about 3% of total U.S. energy consumption. In general, refinery energy consumption, both total and per barrel of crude through-put, has tended to increase slowly over time. This trend reflects U.S. refiners' gradual shift to a heavier, higher sulfur crude slate, coupled with increasingly stringent specifications on refined products, particularly the sulfur standards for gasoline and diesel fuel.

Exhibits 4.1, 4.2, 4.3, and 4.4 show information on energy consumption in the U.S. refining sector in 2005, 2006, and 2007. Most of this information was obtained from Energy Information Administration (EIA) *Petroleum Supply Annuals* and the EIA website.

4.1 Total Refinery Energy Use

Exhibit 4.1 shows total annual refinery energy consumption, crude throughput, and average energy consumption per barrel of crude through-put, by PADD.[14]

Exhibit 4.1: Reported U.S. Refinery Energy Use, By Region, 2005-2007

Region	Refinery Energy Use (Quads/Year)			Crude Throughput (1) (Million Bbl/Day)			Avg. Energy Use per Bbl Crude (Million BTU/Bbl Crude)		
	2005	2006	2007	2005	2006	2007	2005	2006	2007
U.S.	3.019	3.123	3.090	15.220	15.242	15.156	0.543	0.561	0.559
PADD 2	0.582	0.588	0.585	3.298	3.297	3.226	0.483	0.489	0.497
PADD 3	1.478	1.600	1.557	7.098	7.260	7.315	0.570	0.604	0.583
PADD 5	0.572	0.565	0.574	2.638	2.621	2.560	0.594	0.591	0.614

Source: *Petroleum Supply Annuals* for 2005, 2006, and 2007; Energy Information Administration

(1) **Crude Throughput** volumes include unfinished oils

(2) California accounts for about 80% of PADD 5 refinery energy use

PADD 5 generally shows the highest per-barrel energy use, reflecting primarily the refining operations in California, where the aggregate crude slate is particularly heavy and the product specifications are the most stringent in the U.S.

---

[14] Our analysis considers PADD 2, PADD 3, and California (but not PADD 5, which includes California). Exhibits 4.1 and 4.2 show values for PADD 5 rather than for California because the *Petroleum Supply Annuals* provide data on refining operations by PADD, not by state. However, California accounts for about 80% of the refining capacity and crude runs in PADD 5.

4.2 Sources of Refinery Energy

The energy consumed in refining comes from various sources; some from outside the refinery – such as purchased natural gas and electricity – and some generated within the refinery by the destruction of crude oil – such as still gas and catalyst coke.

> *Still gas* is a mixture of light gases (methane, ethane, etc.) produced as by-products in various refining processes. These light gas streams are collected, treated, and sent to the refinery fuel system.
>
> *Catalyst coke* – coke laid down on the cracking catalyst – is a by-product of the cracking reactions that occur in the FCC reactor. The coke is burned off the catalyst in the FCC regenerator. The heat of combustion is used to provide process energy for the FCC unit and to generate refinery steam.
>
> (*Petroleum coke* (or *marketable coke*) – which is not used as a refinery fuel – is the primary by-product of refinery coking units (cokers). Coke usually constitutes ≈ 25%–35% of coker output and has various uses outside the refining industry.)

Exhibit 4.2 shows annual U.S. refinery energy use (quads/year), by energy source (fuel type) and by PADD, in 2005, 2006, and 2007.

The values in Exhibit 4.2 are derived from various EIA sources[15] and the EIA website. As the exhibit indicates, EIA tracks and reports essentially all sources of refinery energy, large and small. However, four sources – still gas and catalyst coke (refinery-produced) and natural gas and electricity (purchased) – account for about 95% of reported U.S. refinery energy consumption.

> (EIA does not treat natural gas used in refinery hydrogen production as a fuel use. Nor does EIA include in its reporting the natural gas used as fuel by merchant hydrogen plants supplying hydrogen to the refining sector.)

Exhibit 4.3 shows annual refinery energy use (2005-2006), by energy source for California (only). EIA reports refinery energy use by PADD, but not by state. We developed Exhibit 4.2 using data provided by the California Energy Commission (CEC). We revised the petroleum coke and natural gas values provided by CEC to make them consistent with EIA's reported values for PADD 5.

---

[15] *Petroleum Supply Annual*; *Table 47*; Department of Energy/ Energy Information Administration
More references needed

Exhibit 4.2: Refinery Fuel Use Reported by EIA (2005-2007), by PADD and Source

		Unit of	MM btu/	Refinery Fuel/Energy Use		
Region	**Type of Fuel**	**Measure**	**fuel unit**	**2005**	**2006**	**2007**
U.S.	**Energy Use**	Quads		**3.231**	**3.352**	**3.338**
	LPGs	K Bbl	3.8	4,175	2,656	2,663
	Distillate	K Bbl	5.8	755	434	420
	Residual Fuel	K Bbl	6.3	2,207	2,018	1,844
	Still Gas (@ 6.0MM btu/foeb)	K foeb	6	238,236	249,358	247,106
	Marketable Petroleum Coke	K Bbl	6.02	2,242	458	648
	Catalyst Petroleum Coke	K Bbl	6.02	87,410	90,034	87,367
	Other Products	K Bbl	5.25	5,329	6,327	3,704
	Natural Gas	Mcf	1.1	682,919	697,593	667,986
	Coal	K tons	21	41	34	39
	Purchased Electricity	MM Kwh	9.977	36,594	39,353	41,829
	Purchased Steam	MM lbs	1.3	63,591	70,769	99,022
PADD 2	**Energy Use**	Quads		**0.641**	**0.651**	**0.649**
	LPGs	K Bbl	3.8	779	567	842
	Distillate	K Bbl	5.8	50	45	47
	Residual Fuel	K Bbl	6.3	163	206	189
	Still Gas (@ 6.0MM btu/foeb)	K foeb	6	50,213	49,585	49,429
	Marketable Petroleum Coke	K Bbl	6.02	0	0	0
	Catalyst Petroleum Coke	K Bbl	6.02	17,342	16,502	15,701
	Other Products	K Bbl	5.25	1,686	1,961	395
	Natural Gas	Mcf	1.1	106,480	114,721	120,047
	Coal	K tons	21	8	3	7
	Purchased Electricity	MM Kwh	9.977	9,875	10,488	10,555
	Purchased Steam	MM lbs	1.3	5,033	7,298	10,738
PADD 3	**Energy Use**	Quads		**1.575**	**1.708**	**1.678**
	LPGs	K Bbl	3.8	359	277	208
	Distillate	K Bbl	5.8	86	111	115
	Residual Fuel	K Bbl	6.3	4	1	3
	Still Gas (@ 6.0MM btu/foeb)	K foeb	6	111,798	125,046	120,930
	Marketable Petroleum Coke	K Bbl	6.02	29	194	58
	Catalyst Petroleum Coke	K Bbl	6.02	41,270	45,395	42,690
	Other Products	K Bbl	5.25	1,300	1,971	1,510
	Natural Gas	Mcf	1.1	395,980	395,627	363,004
	Coal	K tons	21	0	0	0
	Purchased Electricity	MM Kwh	9.977	16,620	18,612	20,433
	Purchased Steam	MM lbs	1.3	34,738	38,999	63,471
PADD 5	**Energy Use**	Quads		**0.599**	**0.593**	**0.602**
	LPGs	K Bbl	3.8	2,291	1,468	1,415
	Distillate	K Bbl	5.8	253	255	236
	Residual Fuel	K Bbl	6.3	727	770	743
	Still Gas (@ 6.0MM btu/foeb)	K foeb	6	45,700	44,999	45,553
	Marketable Petroleum Coke	K Bbl	6.02	970	110	117
	Catalyst Petroleum Coke	K Bbl	6.02	14,401	14,440	14,404
	Other Products	K Bbl	5.25	1,700	2,199	1,716
	Natural Gas	Mcf	1.1	123,271	126,190	133,713
	Coal	K tons	21	0	0	0
	Purchased Electricity	MM Kwh	9.977	4,978	4,973	5,113
	Purchased Steam	MM lbs	1.3	17,956	17,999	17,838

Note: Electricity conversion factor represents btu's in delivered power adjusted for generation efficiency and transmission loss.

Source: Derived from EIA Website.

Exhibit 4.3: Refinery Fuel Use (2005-2006) in California, by Source

Region	Type of Fuel	Unit of Unit of Measure	MM btu/ fuel unit	Refinery Fuel/ Energy Use 2005	2006	Note
California	**Energy Use**	Quads		**0.495**	**0.483**	
	LPGs	K Bbl	3.8	1,706	1,015	
	Distillate	K Bbl	5.8	155	78	
	Residual Fuel	K Bbl	6.3	0	0	
	Still Gas (@ 6.0MM btu/foeb)	K foeb	6	40,795	39,824	
	Marketable Petroleum Coke	K Bbl	6.02	776	88	X
	Catalyst Petroleum Coke	K Bbl	6.02	11,675	11,704	
	Other Products	K Bbl	5.25	4	6	
	Natural Gas	Mcf	1.1	109,407	108,895	X
	Coal	K tons	21	0	0	
	Purchased Electricity	MM Kwh	9.977	3,096	3,244	
	Purchased Steam	MM lbs	1.3	12,508	12,712	

Note: Electricity conversion factor represents btu's in delivered power adjusted for generation efficiency and transmission loss.
"X" indicates data provided by CEC were revised to be consistent with data reported by EIA for PADD 5.
Source: Derived from from data provided by CEC and from EIA Website.

4.3 Refinery Generation of Electricity

Exhibit 4.4, derived from the EIA-906 and EIA-920 surveys, summarizes U.S. refinery electricity generation, by region, for 2006.

Exhibit 4.4: Power Generation in U.S. Refineries, 2006

Region	Gross Power Generation (1)		Sales to Grid (1)		Share of Gross Power Sold to Grid	Net Power Generation (2)	
	(M Kwh)	(M Kwh/day)	(M Kwh)	(M Kwh/day)		(M Kwh)	(M Kwh/day)
PADD 1	1310.0	3.6	157.4	0.4	12.0%	1152.5	3.2
PADD 2	814.0	2.2	0.0	0.0	0.0%	814.0	2.2
PADD 3	12004.0	32.9	2398.8	6.6	20.0%	9605.2	26.3
PADD 4	206.8	0.6	198.7	0.5	96.1%	8.2	0.0
PADD 5	8593.1	23.5	3794.7	10.4	44.2%	4798.4	13.1
California	8313.1	22.8	3783.4	10.4	45.5%	4529.7	12.4
Total	**22927.8**	**62.8**	**6549.6**	**17.9**	**28.6%**	**16378.3**	**44.9**

(1) Derived from *Annual Sources and Disposition of Electricity for Non-Utility Generators, 2006;*
EIA-906 and EIA-920 Surveys; EIA Website
(2) **Gross Power Generation** minus **Sales to Grid**

Exhibit 4.4 indicates that gross electricity generation in U.S. refineries averaged about 2½ gigawatts (63 gigawatt-hours per day) in 2006. Most of the refinery-generated electricity came from gas-fired co-generation units. U.S. refineries sold about 29% of gross electricity output to the grid. The indicated net electricity generation for internal use in U.S. refineries (after sales to the grid) was about 1.9 gigawatts.

It appears that the refinery purchases of natural gas reported by EIA (as shown in Exhibit 4.2) include natural gas used for power generation, without adjustment for refinery sales of electricity to the grid. Refinery purchases of electricity natural reported by EIA reflect purchases from the grid and do not include refinery-generated electricity. We adjusted the EIA data to reflect their reporting framework in our analysis of refinery energy use.

5. THE ENERGY AND CO_2 ACCOUNTING FRAMEWORK IN THE REGIONAL REFINING MODELS

5.1 Background

In principle, one can envision at least two approaches for estimating refinery use and CO_2 emissions as a function of a refinery's crude oil slate.

The more rigorous approach is to develop complete energy, material, and carbon balances around the refinery. The difference between the energy embodied in all refinery outputs and inputs equals the energy expended in the refinery. Similarly, the difference between the total carbon content of all refinery outputs and inputs equals the refinery's carbon emissions, some of which will be in the form of CO_2. At first glance, this approach is appealing because it rests on the fundamental chemical engineering principles of heat and material balance. In practice, the approach is unworkable. It requires (1) complete and tight material and energy balances for the refinery (including not only all refinery feed and product streams but also waste streams and losses, such as furnace exhaust, flare gas, fugitive emissions, waste water, etc.) and (2) precise estimates or measurements of the energy and carbon content of each refinery input and output. Such measurements are subject to day-to-day fluctuation and, in many cases, are simply unavailable. Moreover, because the desired results of the analysis – refinery energy use and CO_2 emissions – are residuals, the inevitable gaps in refinery material balances and inaccuracies in energy and carbon content – even small ones – would render the results useless.

The more practical approach focuses on energy consumption within the refinery battery limits. This approach involves

- Estimating total refinery energy use, process-by-process – that is, by summing the direct energy inputs to each refining process, by energy source (natural gas, refinery-generated fuel, petroleum coke, electricity); and then
- Estimating refinery CO_2 emissions by applying standard carbon emission factors to each of the refinery energy sources.

The latter approach is the standard one and the one followed in this study. In theory, it is less rigorous than the first approach, but it is practical and adequate to the purpose. It does not require precise (and indeed unattainable) material and energy balances, and it can be implemented through refinery LP models.

5.2 Refinery Energy Accounting in the Regional Refining Models

The engineering representation of each refining process in our refinery LP models includes the process's consumption (or production) of refinery fuel, steam, and electricity, as functions of operating conditions and feeds. In the models, the energy flows are expressed as foeb (fuel oil equivalent barrels) of fuel, K lbs (thousand pounds) of steam, and Kwh (kilowatt-hours) of electricity per barrel of process throughput. The energy input/output coefficients for each process reflect information provided by technology providers (i.e., process developers and licensors) in public sources and, in some cases, private communications.

The models sum energy consumption (net of energy production) across all processes and set aggregate refinery energy consumption equal to refinery energy supply, by energy source:

- Purchased natural gas, for use as refinery fuel (and as feed to hydrogen production)
- Refinery fuel gas streams (e.g., still gas) generated as co-products or waste products in certain processes
- Catalyst coke produced generated in the fluid catalytic cracking (FCC) unit
- Purchased electricity

These sums capture the various effects of crude oil properties on refinery energy use represented in the models, examples of which are discussed in Section 2.6. Hence, changes in crude slate, product slate, and/or product specifications (e.g., sulfur content) will, in general, lead to corresponding changes in the refinery energy use returned by the regional refining models used in this study.

The refining models represent all on-purpose hydrogen used by refineries as being produced in the refinery (rather than some being produced by merchant hydrogen plants[16]) and all electricity used by refineries as being purchased (rather than some being internally generated). Hence, refinery energy use in the models includes natural gas used as fuel in the production of hydrogen purchased from merchant plants (located outside the refinery battery limits). We adjusted refinery natural gas consumption and electricity purchases to account for the refinery co-generation reported by EIA.[17]

The refinery energy use in the models does not include (1) energy used in production and transport of ethanol blended into gasoline downstream of the refinery; (2) energy used in production and supply of unfinished oils (refinery inputs other than crude oil) blended into gasoline and distillate fuels in the refinery, but not otherwise processed in the refinery; (3) electricity used in non-process or off-site activities (such as oil movements in and out of storage, product blending, lighting, etc.); and (4) energy losses due to flaring, fugitive emissions, etc.

5.3 Normalization to EIA Reporting of U.S. Refinery Energy Use

---

[16] Merchant hydrogen plants are not in the refinery proper, but the energy they use and the CO_2 they generate in producing hydrogen for refinery use are directly connected with refinery operations. In effect, the refinery models treat purchased hydrogen as though the merchant hydrogen plants were integral parts of the refining sector.

[17] *Annual Source and Disposition of Electricity for Non-Utility Generators, 2006*; EIA Report 906 and 920 Surveys; Energy Information Administration

The energy accounting framework described above should tend to produce estimates of regional refinery energy use somewhat lower than the "actual" values shown in the EIA reports, for three reasons. First, the refining models do not explicitly represent some auxiliary refinery process units (such as certain distillation and other separation processes), whose operation consumes some energy. Second, the models do not capture the energy that real refineries use in non-process or off-site activities (described above). We assume that refineries include such energy use in their reporting to EIA. Third, the refining models' representation of energy use in the individual refining processes is based on information provided by technology providers (i.e., process developers and licensors). In our view, such information usually reflects best-practice operation of new process units at design conditions, and therefore probably understates actual energy consumption of the existing refinery capital stock in day-to-day refining operations.

Without adjustment for these factors, the energy accounting framework in the refining models still produce reasonable estimates of regional refinery energy use. Unadjusted estimates of total refinery energy use in the U.S. developed with our refinery modeling system for year 2006 were within 20% of that reported by EIA for that year (Exhibit 4.1).

However, given the objective of this analysis, we chose to normalize the estimates of refinery energy use returned by the regional refining models such they matched the total refinery energy use reported by EIA, by region, for a base year: 2006. That is, we developed a computational procedure to adjust the refinery energy use values returned by the regional refining models applied to 2006 so that these results matched the adjusted values reported by EIA, by region, for 2006. Then, we applied this procedure to the results returned by the models in the various study cases to estimate refinery energy use for each of the thirteen crude oils.

Normalizing to EIA-reported values was complicated by several factors.

First, the energy accounting framework in the regional refining models differs in some ways from that used by EIA in gathering and reporting data on U.S. refinery energy use. For example, as Exhibit 4.2 indicates, EIA tracks and reports more sources of refinery energy than the four explicitly represented in our refinery models.[18] As noted earlier, the four primary sources account for about 95% of reported U.S. refinery energy consumption. In effect, the refining models treat the refinery energy provided by the other sources (e.g., residual fuel, coal, purchased steam, etc.) as though it came from purchased natural gas.

Second, EIA's reporting framework for refinery energy does not include natural gas used as either feed or fuel in merchant hydrogen plants. Hence, without suitable adjustment, EIA's reporting of refinery energy use would lead to estimates of CO_2 emissions that did not include emissions resulting from hydrogen production. The total amount of natural gas used in all hydrogen production – both refinery and merchant plants – is relatively small, but in the context of this study it is a significant contributor to total refinery energy use and CO_2 generation.

---

[18] Some of the small-volume energy sources reported by EIA may reflect losses (due to spillage, leaks, etc.) rather energy production.

Finally, as noted in Section 4, refinery purchases of natural gas reported by EIA include natural gas used for power generation, without adjustment for refinery sales of electricity to the grid, and refinery purchases of electricity natural reported by EIA reflect purchases from the grid and do not include refinery-generated electricity.

5.4 Refinery CO_2 Emissions Accounting

We used standard CO_2 emissions factors, shown in **Exhibit 5.4**, to convert computed volumes of purchased natural gas, refinery fuel gas streams, FCC catalyst coke, and purchased electricity to refinery emissions of CO_2. The emissions factors are drawn from an American Petroleum Institute publication[19] and are similar to factors published by the IPCC.

The estimates of refinery CO_2 generation returned by the regional refining models reflect fuel consumption in all refining processes, as well as the natural gas used as feed for all on-purpose hydrogen production.

Exhibit 5.4: CO2 Emission Factors in the Regional Refining Models

Refinery Energy Source	CO_2 Emission Factor (Me Tons/MM BTU)
Natural gas	0.0531
Still gas	0.0642
Petroleum coke	0.1020
Electricity (purchased)	0.0639
Electricity (refinery-generated)	0.0531

Note:
Purchased electricity factor reflects 50%/30%/20% sourcing from coal, natural gas, and nuclear + renewables, respectively.

---

[19] Source: "*Toward a Consistent Methodology for Estimating GHG Emissions*"; American Petroleum Institute

6. OVERVIEW OF THE REFINERY MODELING METHODOLOGY

This section briefly discusses the development and application of the methodology for estimating refinery energy use and CO_2 emissions for the specified crude oils. The discussion covers eight topics.

1. Refinery LP models
2. Data sources for the analysis
3. Developing the models
4. Calibrating the models (*calibration* cases)
5. Normalizing refinery energy use factors
6. Establishing baseline values for the analysis (*reference* cases)
7. Allocating refinery energy use and CO_2 emissions to refined products (*study* cases)
8. Estimating refinery energy use and CO_2 emissions, by crude oil and region (*study* cases)

6.1 Refinery LP Models

We conducted the analysis of refinery energy use and CO_2 emissions using linear programming (LP) models of aggregate refining operations: one national refining model and three regional refining models, representing the refining centers in the Midwest (PADD 2), the Gulf Coast (PADD 3), and California. Each model is an analytical construct representing aggregate refining capacity in a region of interest, processing a composite crude oil slate and producing a slate of refined products. We used the national refining model to estimate the shares of refinery energy use attributable to the various refined product categories. We used the regional refining models to estimate refinery energy use and CO_2 emissions for each specified crude oil/refining region combination.

Linear programming (LP) is a rigorous mathematical modeling technique for obtaining optimal (e.g., cost-minimizing) solutions to technical and economic problems. Refinery LP models are detailed, engineering representations of the primary refinery process operations and the material flows between processes. Since the mid-1950's, LP modeling has been the method of choice for refinery operations and investment planning, as well as techno-economic analysis of refining operations in general. LP modeling has achieved this status because it is uniquely suited to capturing the technical and economic essentials of refining operations.

With respect to this study, refinery LP modeling captures the key analytical elements of refining operations discussed in Section 2.3: complexity, co-product production, and distributed energy use.

We constructed the four refining models using MathPro's proprietary refinery modeling system (**ARMS**), which includes a library of crude assay data, technical characterizations of refining processes, and blendstock properties. Though developed from a common data base, the models are distinct in terms of aggregate refining process capacity, composite crude oil slate, refinery inputs and outputs, refined product specifications, and, in some instances, representations of individual refining processes.

Finally, we developed and applied the national model and each regional model through a sequence of *calibration*, *reference*, and *study* cases.

6.2 Primary Data Sources

In developing the various data elements in the models, we relied on the following published sources of U.S. refining data.

- Refining process capacity

    - "*2006 Worldwide Refinery Survey*"; Oil & Gas Journal; Dec. 18, 2006
    - "*2006 Refinery Capacity Survey*"; Energy Information Administration (EIA) website
    - "*2007 California Refinery Survey*"; California Energy Commission

- Crude oil slate

    - "*2006 Company-Level Import Data*"; EIA Website
    - "*2006 Petroleum Supply Annual, Table 17*"; EIA website
    - "*2007 California Refinery Survey*"; CEC
    - "*Crude Oil Production Data*"; State-Level, Monthly; EIA Website;

- Refinery inputs and outputs

    - "*Petroleum Supply Annuals, Tables 17 and 18*"; EIA website
    - "*Petroleum Industry Information Reporting Act (PIRA) Data,2006*"; CEC website;
    - "*Weekly Fuels Watch Reports*" for 2006; CEC website

- Refined product specifications

    - "*RFG Area Surveys for 2006*"; Environmental Protection Agency (EPA) website
    - "*Average Conventional and Reformulated Gasoline Properties for 2006*"; provided by EPA
    - ASTM Standard D4814-06; "*Table 1: Vapor Pressure and Distillation Class Requirements*" and "*Table 4: Schedule of Seasonal and Geographical Volatility Classes*"
    - "*2007 California Refinery Survey*"; CEC
    - "*1996 API/NPRA Survey of Refining Operations and Product Quality*"; American Petroleum Institute and National Petroleum Refiners Association; July 1997

- Refinery fuel use
  - "*Refinery Fuel Use, 2006*"; EIA website
  - "*California Refinery Fuel Use for 2006*"; provided by California Energy Commission;
  - "*Annual Sources and Disposition of Electricity for Non-utility Generators, 2006*"; EIA website

Exhibits A-1 to A-4 (in Appendix A) show the data we developed in the first four categories for the regional refining models, for the year 2006. Exhibit A-1 shows aggregate refining process capacity. Exhibit A-2 shows derived distillation curves and properties for the regional composite crude slates. Exhibit A-3 shows regional refinery input and output volumes. Exhibit A-4 shows product specifications for gasoline and diesel fuel. (Exhibits 4.2 and 4.3 show our estimates of refinery fuel use, by region and fuel type.) All of these data elements appear, in one form or another, in the refining models used in the study.

6.3 Model Development: Year 2006

Initially, we developed the national model and the regional refining models to represent annual average refining operations (in particular, refining process capacity, crude oil slate, refinery inputs and outputs, and product specifications) in 2006. Development of these models involved the following steps.

- Endow each model with the total refining process capacity reported for each region, process by process (e.g., cat cracking, alkylation, etc.), as of 1 January 2007.

- Set the volume shares of desulfurized and untreated FCC feed to conform to the reported process capacities of gas oil (FCC feed) hydrotreating and FCC units.

  We constrained the sulfur content of the gas oil feeds to the FCC feed hydrotreater so as to match our estimates of the average sulfur content of gas oils processed by refineries with FCC feed hydrotreaters in each region. In the California model, we required desulfurization of all FCC feed, because all California refineries have FCC feed hydrotreaters. We split the hydrotreating capacity between conventional hydrotreating and deep hydrotreating (in effect, mild hydrocracking) on the basis of our estimates of the relative volumes of these types of FCC feed hydrotreating in the California refining sector.

- Set the volume shares of coker gas oil sent to cat cracking (constrained via hydrotreating) and to hydrocracking on the basis of various survey data.

- Limit the crude oil inputs to each regional model to regional composite crude oils, which we developed using the data sources cited above.

  Each regional composite crude oil is a volume-weighted average of the imported and domestic crudes that comprise the region's crude oil slate, according to our estimates.

Hence, the composition and properties of the crude oil slate represented in each regional model are invariant with respect to the volume processed.

- Set the volumes of the refinery inputs of unfinished oils and certain gasoline blendstocks (MTBE, pentanes, alkylate, iso-octane, pyrolysis gas, and toluene) at the reported (or, where necessary, estimated) volumes.

- Set prices of the refinery inputs of crude oil, n-butane, and iso-butane and allow the input volumes to vary (subject to upper limits corresponding to reported input volumes).

- Set the volumes of ethanol use as follows.

  - For ethanol used in conventional gasoline (CG), set an upper limit on volume equal to the sum of (1) the volume of ethanol reported by refineries for producing finished, ethanol-blended conventional gasoline on-site (i.e., at the refinery) and (2) the volume of ethanol commensurate with 10 vol% ethanol blending with CBOBs.[20]

  - For ethanol used in reformulated gasoline (RFG), set an upper limit equal to the sum of: (1) the volume of ethanol reported by refineries to make finished, ethanol-blended RFG on-site and (2) the volume of ethanol commensurate with 10 vol% ethanol blending with RBOBs (except in California where the ethanol blending rate was 5.7 vol% in CaRFG).[21]

- Set the volumes of purchased MTBE at the reported volumes.

- Fix the volumes of most refined product outputs at the reported (or, where necessary, estimated) volumes.

- Set prices of two refinery outputs – propane (for LPG) and petroleum coke – and allow the output volumes returned by models to vary in response to the specified prices.

- Specify the product specifications for conventional gasoline, RFG, jet fuel, diesel fuel (on- and off- road and CARB), and residual oil using the above cited data sources.

All of these elements represented annual operations (averages of summer and winter operations).

---

[20] The refining models were set up to produce all finished gasoline, rather than the mixture of gasoline products – finished gasoline, RBOB (Reformulated Blendstock for Oxygenate Blending), and CBOB (Conventional Blendstock for Oxygenate Blending) – reported by EIA.

RBOB and CBOB are base gasoline blends to which ethanol is added at terminals, downstream of the refinery, to produce, respectively, finished federal reformulated gasoline and conventional gasoline.

[21] CaRFG stands for California reformulated gasoline (which differs from federal RFG). The base gasoline for CaRFG is called CARBOB.

6.4 Calibrating the Models to 2006 Refining Operations

Consistent with our standard practice in studies of refining operations, our first step in applying the regional models was to *calibrate* each model to the corresponding regional refining operations in a prior time period – in this instance, 2006. Well-calibrated models provide assurance that subsequent uses of the models will adequately represent refining operations under alternative sets of requirements, such as refined product standards, and/or with different crude and product slates.

Calibrating a refining model involves adjusting some of the model's internal technical coefficients – such as yields from refining processes, blending properties of refinery streams, or process capacity utilization rates – as needed so that solutions returned by the model closely approximate reported refining operations. In calibrating the regional refining models this study, we modified the initial specification of the models (discussed above) in various ways, including:

- Allowing the model to represent additions of new capacity in (1) various separation (splitting) processes, (2) FCC naphtha desulfurization, and (3) benzene saturation, to facilitate meeting refined product specifications or shifting the boiling range cut points of distillate products

- Adding additional hydrogen plant capacity to simulate production of hydrogen purchased from merchant plants

- Changing the boiling range cut points for vacuum gas oils to better match reported feed rates to coking and fluid cat cracking

- Allowing the retrofitting (at a cost) of existing conventional distillate desulfurization units to meet the new ULSD standard ($\leq$ 15 ppm) for the sulfur content of diesel fuel

- Modifying the yields of petroleum coke (in the coker) and catalyst coke (in the FCC unit) to better approximate reported volumes of marketable and catalyst coke; and

- Modifying a few refined product specifications, primarily distillation temperature and cetane number (for diesel fuel), when these specifications constrained the model from making certain refined products.

The reported refining operations to which we calibrated included crude oil throughput; feed rates to fluid cat cracking, delayed coking, and fluid coking; production volumes of marketable (petroleum) coke and of catalyst coke; and (importantly) the marginal costs (shadow values) of producing the major refined product categories (gasoline, jet fuel, diesel fuel, and residual fuel).

Regarding the marginal costs of production returned by the models, the objective of the calibration was to ensure that (1) the marginal costs of the various refined products bear the same general relationship as do the reported market prices for these products, (2) the marginal costs of meeting various product specifications are reasonable, and (3) the marginal value of various intermediate refinery streams and blendstocks are reasonable in relation to product prices. Meeting these criteria is essential even when, as in this study, the refining analysis does not focus primarily on refining economics.

Exhibits B-1 and B-2 (Appendix B) show, respectively, refinery inputs and outputs and refinery process capacity, by unit, for the calibrated regional models.

6.5 Normalizing Refinery Energy Use Estimates Returned by the Models

As discussed in Section 5, we expected raw (unadjusted) estimates of aggregate refinery energy use returned by our refinery models to be somewhat lower than the values reported by EIA (as adjusted for refinery-generated power sold to the grid). The models do not represent certain auxiliary refining processes. The energy use factors for the various refining processes represented in ARMS reflect recent information published by refining technology providers. This information most likely represents best-practice energy use in new process units, rather than average energy use across actual units of various vintages. Finally, the refining models represent fuel and power consumption only for direct refinery processing, not for ancillary operations (e.g., oil movement, storage, blending, effluent treating, etc.).

To deal with this situation, we developed a post-model *regional normalization procedure* for refinery energy use. The normalization procedure transforms the estimates of refinery energy use, by energy source, returned by the national and regional refining models into estimates consistent with those reported by EIA and CEC. We developed the normalization procedure by conforming the refinery energy use values returned by the national and regional models in the calibration cases (representing year 2006) to corresponding refinery energy use estimates for 2006 developed from EIA and CEC reports.

Exhibits C-1a and C-1b (Appendix C) show the normalization factors derived for the national and regional models, respectively. In developing the normalization factors, we made several adjustments to the values reported by EIA and CEC.

As noted in Section 4, the EIA (and CEC) reports on refinery energy use include refinery purchases of natural gas for generating power, whether for internal use or sale to the grid. Using an EIA database of non-utility power generators, we estimated regional refinery-based power generation and the percentage of such power sold to the grid (shown in Exhibit 4.4). We then

- Subtracted from reported refinery purchases of natural gas for fuel our estimate of the volume of natural gas used for all refinery-based power generation; and

- Added to the reported refinery purchases of power our estimate of the amount of refinery-generated power that was used internally.

This procedure essentially (1) removes from the refineries' energy balance sheet the energy (from natural gas) used to generate power sold to the grid – energy that is not used in processing crude oil into refined products – and (2) shifts the natural gas used to generate power for internal use into an equivalent amount of purchased electricity. The latter adjustment reflects our practice of representing refineries as purchasing all of the electricity they use.

We applied the normalization factors uniformly to the refinery energy use estimates returned by the refining models in the reference and study cases.

6.6 Establishing Baseline Values for the Analysis (*Reference* Cases)

Developing the regional refining models, calibrating them, and normalizing the estimates of refinery energy use returned by the calibrated models are prerequisite steps to the methodology that we used to allocate refinery energy use to refined product categories and to estimate refinery energy use and CO_2 emissions for each crude oil/refining region combination and.

The first step in the methodology was to establish national and regional baselines. In this instance, the baseline values are the solutions returned by models for the *reference* cases. We developed reference cases, rather than simply using the 2006 calibration cases as the baseline cases, because significant changes in the regulatory landscape bearing on fuel quality and ethanol blending have occurred since 2006 and others will occur over the next several years. The new (i.e., post-2006) regulatory programs and standards include:

- National Tier 2 gasoline sulfur standards (average sulfur level in gasoline < 30 ppm)
- National MSAT 2 standards on toxic emissions from gasoline (average benzene levels in gasoline < 0.62 vol%)
- National Ultra-Low Sulfur Diesel (ULSD) standard (maximum sulfur level in on-road and off-road diesel < 15 ppm)
- National roll-out of the new Renewable Fuel Standard (RFS2) in the Energy Independence and Security Act of 2007 (requiring 10 vol% ethanol blending in all RFG and conventional gasoline, along with increased E85 volumes by 2015, most likely in the Midwest) [22]
- California's revisions to the state's reformulated gasoline program (CARB 3) and amendments to its Predictive Model (PM-3) for certifying CARB 3 gasoline batches (to facilitate ethanol blending at 10 vol% and to account for the permeation emissions associated with ethanol blending)

These regulatory developments will be fully implemented by 2015.

In addition, we assumed that the main regulatory programs affecting gasoline properties that were in full effect in 2006 would continue. In particular, we assumed that the 1 psi RVP waiver

---

[22] The RFS2 standard mandates annual increases in renewable fuels volumes through 2022.

for ethanol blending in the summer would remain in effect in its present form, covering all gasoline types except for federal RFG and California RFG.

We incorporated the impending new regulatory requirements in the national and regional refining models by suitably modifying the refined product standards and requiring 10 vol% ethanol blending in all gasoline, both conventional and reformulated.

In establishing the reference cases, we used projections of U.S. refinery inputs and outputs for 2015 drawn from EIA's most recent *Annual Energy Outlook* [23] for the national model and allocated these inputs and outputs proportionately for the regional models, except that we allocated all projected E85 use to PADD 2 and adjusted gasoline volumes in other regions accordingly. The reference cases embody the same crude slates as the calibration cases, because we assumed that the regional crude oil slates would not change significantly between 2006 and 2015.

Exhibits A-3c and A-3d, respectively, show reference case projections of 2015 refinery inputs and outputs for the U.S. and for the refining regions. **Exhibit 6.1** shows the projected volumes (K Bbl/day) and volume shares (vol%) of each product category in the projected 2015 U.S. refined product slate.

Exhibit 6.1: Projected Volumes of Refined Product Categories (2015)

	Projected 2015 Volume		
Refined Product Category	**(K Bbl/day)**	**(Vol%)**	**Notes**
Gasoline	7267	48.6	(1)
Jet Fuel	1366	9.1	
Diesel Fuel	4142	27.7	(2)
All Other	2165	14.5	(3)
Total	14940	100	(4)

Notes:

1 **Gasoline** volumes are net of ethanol and other purchased blendstocks.
2 **Diesel fuel** volumes include other distillate products, such as No. 2 heating oil.
3 **All other** includes LPG, petrochemical feedstocks, unfinished oils,
residual fuel, asphalt, and lubes and waxes.
4 **Total** excludes marketable coke.

---

[23] *Annual Energy Outlook, 2009 (Early Release)*; EIA website

We selected 2015 as the target year for the analysis because the regulatory developments discussed above will be fully implemented by then. With these regulations in place, the choice of year for the reference cases will, in our judgment, have only negligible effects on the estimates of per barrel energy use and CO_2 emissions obtained with the methodology described here.

6.7 Estimating Refinery Energy Use and CO_2 Emissions (*Study* Cases)

With the national and regional baselines established via the reference cases, the next step in the modeling methodology involved developing and analyzing a set of *study* cases.

The study cases for allocating refinery energy use to refined product classes represented the U.S. refining sector as a whole and were analyzed with the national refining model.

The study cases for estimating refinery energy use and CO_2 emissions by crude oil and refining region each represented a particular crude oil/region combination and were analyzed with the appropriate regional refining model. Exhibit 1.1 shows the crude oil/region combinations analyzed in these study cases.

6.7.1 Allocating Refinery Energy Use and CO_2 Emissions to Refined Products

Each of the four study cases in this part of the analysis pertained to one product category: *gasoline*, *jet fuel*, *diesel fuel* (and other distillate products), and *all other refined products*.

The analysis produced estimates of U.S. refinery energy use associated with each product category (in MBTU/Bbl) and of the corresponding CO_2 emissions (in MeTons/Bbl), for use in the Life Cycle Analysis framework of choice (e.g., GREET). We used the national refining model, rather than the regional models, for this analysis because the results were to be applicable to all U.S. refining regions.

The analysis employed an incremental refined product substitution procedure, comprising the following steps.

1. Estimate baseline values of U.S. aggregate energy use and CO_2 emissions (as discussed in Section 6.6).

2. For each product category in turn, estimate the change in aggregate energy use associated with a small (1%) reduction in its production volume; holding all other refinery outputs and all refinery inputs constant.

   The values of total refinery energy use and calculated CO_2 emissions in this case are lower than the baseline values, with the differences entirely attributable to the specified decrement in the volume of the specified product.

3. Calculate refinery energy use per barrel of refined product, for each refined product category.

The computation involves (1) calculating energy allocation factors for each product category equal to the reduction in energy use for a given product category (returned in Step 2) divided by the sum of the reductions in energy use across all product categories; (2) calculating per barrel energy use for each product category equal to the product category's allocation factor times total refinery energy use in the study case divided by the specified volume of the product category.

4. Calculate CO_2 emissions per barrel of refined product, for each refined product category.

   The computation involves (1) calculating per barrel fuel use (by fuel type) for each product category as energy use is calculated in Step 3; (2) multiplying per barrel fuel use by the corresponding CO_2 emission factors (Exhibit 5.4); and (3) calculating CO_2 emissions per barrel of each product category as the sum of CO_2 emissions for each fuel type, for that category.

Exhibit C-2 provides additional detail on this procedure, in numerical form.

6.7.2 Estimating Refinery Energy Use and CO2 Emissions for Each Crude Oil, by Refining Region

We developed two study cases for each crude oil/region combination, which we called *FIX* and *FLOAT*. In the FIX cases, which were the primary cases (and which we discuss first), we held essentially all refinery inputs and outputs constant at their baseline values. In the FLOAT cases, we allowed refinery outputs to vary within relatively narrow limits.

FIX Cases

The analysis of the FIX cases employed an incremental crude oil substitution procedure, consisting of the following steps.

1. Estimate baseline values of regional energy use and CO_2 emissions (as discussed in Section 6.6)

2. Develop, for each crude oil/refining region combination, a study case incorporating an incremental change in the regional refining model's crude slate: a 100 K Bbl/day reduction in the volume of the region's composite crude and a corresponding increase in the volume of a specified crude oil (e.g., Escravos or Dilbit).

   In the study case, we allowed (1) refinery purchases of butanes (to augment refinery-produced butanes)[24] and (2) investment in new refining capacity, if needed to produce the specified product slate with the amended crude slate. We allowed refinery production of

---

[24] Butanes include n-butane (for direct blending to gasoline) in PADD 2 and i-butane (for feed to alkylation units) in PADD 3 and California.

marketable coke and propane to vary (so as not to over-constrain the models). We held essentially all other model elements and inputs constant.

> We allowed the volume of purchased butanes to vary because we found that an added degree of freedom was necessary to avoid large excursions in the marginal values of the various refinery inputs and outputs from their baseline levels. Such excursions indicate that the regional refinery model is employing unrealistic processing options. We allowed the volumes of marketable coke and propane production to vary because (1) holding all product volumes constant would likely have precluded a feasible solution to the model, and (2) propane and petroleum coke are pure refinery by-products (that is, they are not produced on purpose).

The values of total refinery energy use and CO_2 emissions returned by the regional models were different (higher or lower) than the baseline values. The differences were entirely attributable to the introduction of the given crude oil into the refinery crude slate.

3. Compute, for each crude oil/refining region combination, the refinery energy use and CO_2 emissions per unit (e.g., MM BTU and Bbl) of the given crude oil.

   The computation involves (1) calculating the normalized fuel use, by fuel type, for the modified crude slate in the study case; (2) calculating per-barrel energy use, by fuel type, for the specified crude as total fuel use in the study case minus total fuel use associated with the composite crude slate (the latter being equal to the volume of the composite crude time the baseline per-barrel fuel use for the composite crude); (3) calculating per-barrel fuel use of the specified crude as the sum of the per-barrel energy use from each type of fuel times its energy conversion factor; and (4) calculate per-barrel CO_2 emissions for the specified crude as the sum of the per-barrel use of each fuel type times its CO_2 emissions factor.

This phase of the analysis produced estimates of the incremental refinery energy use and CO_2 emissions attributable to each crude oil in refineries characteristic of each refining region, with the other refinery inputs and outputs product slate essentially constant. Consistent with the discussion in Section 2, these estimates (1) reflect the effects of crude oil properties on refinery energy use (and the consequent CO_2 emissions) required to produce a given product slate to given product specifications and standards and (2) indicate the effects on a given crude's refinery energy use and CO_2 emissions of regional differences in refinery configuration (i.e., process capacity profile) and product slate.

FLOAT Cases

We used a similar methodology in the FLOAT cases, except that we allowed the volumes of gasoline, jet fuel, and diesel production to vary from their baseline values, within the narrow ranges shown below.

➢ PADD 2:	+/- 1%
➢ PADD 3:	+/- ½%
➢ California:	+/- 1½%

In the FLOAT cases, we specified prices for the refined products equal to the marginal production costs ("shadow values") for the products returned in the baseline cases.

The FIX and FLOAT cases were otherwise identical.

We established the FLOAT cases, with their variable product volumes, to more closely simulate the prospective behavior of the refining sector, which would seek to use its crude oil slate in an economically optimal manner – even if the economic optimum were to involve some change in product slate. For purposes of this analysis, we assumed that any changes (up or down) in product volumes would be off-set by corresponding changes in product imports or in the product out-turns of other refining regions. Accordingly, for each FLOAT case, we adjusted the computed refinery energy use to include the delta energy use associated with the off-setting changes in product volumes outside of the region of interest. For this purpose, we used the refinery energy use and CO_2 emissions estimates for each refined product category from the earlier analysis employing the national model (discussed in Section 6.7.1 above).

Exhibits C-3a, C-3b, C-4a, C-4b, C-5a, and C-5b provides additional detail on this procedure, in numerical form, for PADD 2, PADD 3, and California, respectively, and for each region's FIX and FLOAT cases.

7. RESULTS OF THE ANALYSIS

This section presents and briefly discusses the primary results of the analysis:

- Estimates of the aggregate U.S. refining sector's per-barrel energy use in producing each of the four primary product categories
- Estimates of the U.S. regional refining sectors' per-barrel energy use and the resulting CO_2 emissions for each crude oil/refining region combination considered

7.1 Allocation of Refinery Energy Use and CO_2 Emissions to Refined Products

Exhibits 7.1a and 7.1b, respectively, show the estimated allocation of (a) refinery energy use (in MBTU/Bbl) and (b) refinery CO_2 emissions (in MeT CO_2/Bbl) to the primary refined product categories – *gasoline*, *jet fuel*, *diesel fuel*, and *all other* – and to refined products as a whole – designated as *all refined products*.

The product-specific estimates denote changes in refinery energy use and CO_2 emissions per incremental barrel of product volume (with all other product volumes held constant). The all-refined-products estimates reflect average refinery energy use and CO_2 emissions across all refined products.

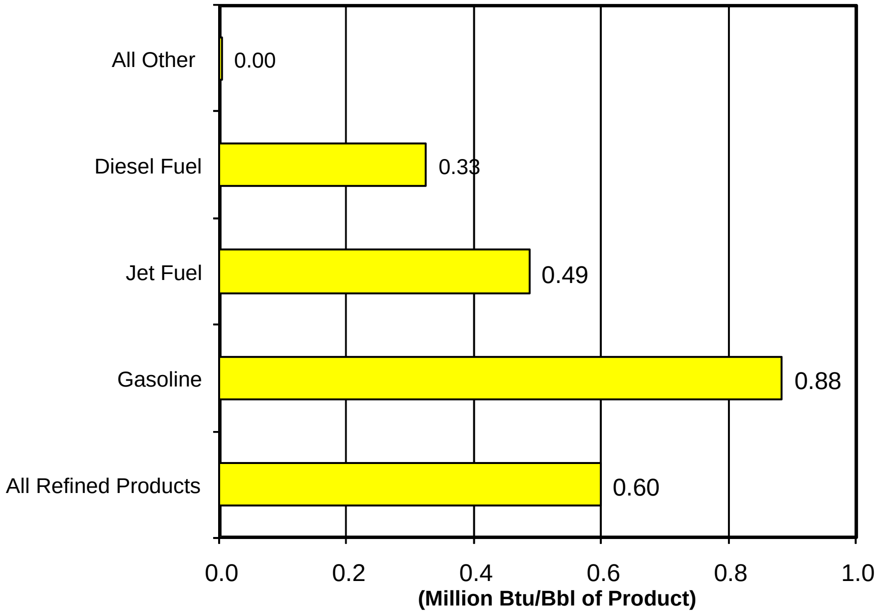
These estimates apply to the U.S. refining sector as a whole, and not necessarily to a particular region (or individual refinery) whose process capacity profile, product slate, and product specifications may differ from the national aggregate.

Gasoline is the most energy-intensive of the four product categories and, correspondingly, the associated refinery CO_2 emissions are the highest of the four. Producing the gasoline volumes demanded in the U.S. calls for extensive conversion of heavy crude fractions to gasoline components, and stringent U.S. gasoline specifications call for extensive upgrading operations. These operations are large consumers of refinery energy.

Jet fuel is the second most energy-intensive product category; its per-barrel energy allocation is a little over half that of gasoline. Like gasoline, jet fuel contains substantial volumes of refinery streams produced by upgrading and conversion processes. However, the specifications that jet fuel must meet do not require as much refinery processing as those for gasoline (or diesel fuel).

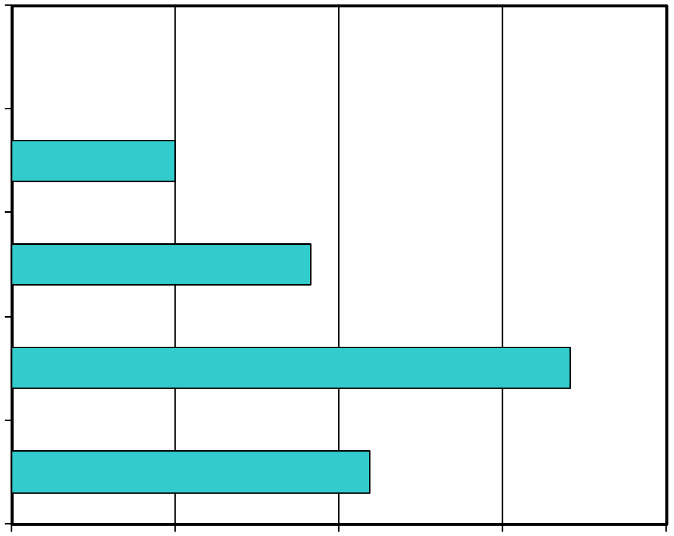
Diesel fuel's energy allocation is a little over one-third that of gasoline (and about two-thirds that of jet fuel). Diesel fuel specifications, especially the stringent sulfur specification (< 15 ppm), call for extensive hydrotreating of diesel fuel blendstocks. However, only a relatively small portion of the diesel fuel volume in U.S. refineries is produced on-purpose (as opposed to being a by-product of conversion operations aimed at producing gasoline blendstocks).

Exhibit 7.1a: Allocation of Refinery Energy Use to Refined Products (U.S Average)



Note: Gasoline includes BTX, propylene, naphthas, aviation gasoline, CBOBs, and RBOBs; excludes purchased gasoline blendstocks (e.g., ethanol). Diesel fuel includes lube oils.

Exhibit 7.1b: Allocation of Refinery CO2 Emissions to Refined Products (U.S Average)



7.2 Estimated Refinery Energy Use and CO2 Emissions, by Crude Oil and Region

Exhibits 7.2, 7.3, 7.4, and 7.5 show estimated refinery energy use (in MBTU/Bbl) and refinery CO_2 emissions (in MeT CO_2/Bbl) for all of the crude oil/region combinations considered. All the exhibits show estimates for both the FIX and the FLOAT cases analyzed for each crude oil/region combination, as well as baseline estimates corresponding to the baseline composite crude oil in region.

Exhibit 7.2 summarizes in tabular form the estimates for the composite crude oil in each region and for all crude oil/region combinations. **Exhibits 7.3, 7.4, and 7.5** show the same results in graphical form for PADD 2, PADD 3, and California, respectively.

Exhibit 7.2: Estimated Refinery Energy Use and CO2 Emissions by Crude Oil, Region, and Case

	PADD 2		PADD 3		California	
	Fix	Float	Fix	Float	Fix	Float
Energy Use (MM Btu/Bbl)						
Composite Crude	0.561	0.561	0.641	0.641	0.641	0.641
West Texas Inter.	0.489	0.507	0.543	0.552		
SJV Heavy					0.754	0.765
Alaskan North Slope					0.576	0.577
Saudi Medium	0.608	0.590	0.673	0.681	0.669	0.650
Basrah Medium			0.673	0.681	0.677	0.655
Escravos			0.501	0.523		
Bachequero 17			0.723	0.732		
Maya			0.722	0.716	0.814	0.716
Bow River	0.647	0.643				
SCO, Mining	0.386	0.357	0.465	0.480	0.526	0.527
SCO, In Situ	0.370	0.396	0.417	0.436	0.415	0.386
Synbit	0.630	0.616	0.724	0.735	0.761	0.770
Dilbit	0.633	0.642	0.687	0.697	0.829	0.748
CO2 Emissions (MeT/Bbl)						
Composite Crude	0.041	0.041	0.046	0.046	0.055	0.055
West Texas Inter.	0.032	0.032	0.033	0.032		
SJV Heavy					0.073	0.074
Alaskan North Slope					0.043	0.044
Saudi Medium	0.048	0.047	0.048	0.049	0.057	0.054
Basrah Medium			0.048	0.049	0.057	0.056
Escravos			0.031	0.031		
Bachequero 17			0.056	0.057		
Maya			0.052	0.053	0.073	0.063
Bow River	0.051	0.053				
SCO, Mining	0.030	0.027	0.033	0.035	0.048	0.044
SCO, In Situ	0.023	0.024	0.023	0.023	0.030	0.028
Synbit	0.053	0.052	0.056	0.057	0.073	0.075
Dilbit	0.053	0.054	0.051	0.053	0.078	0.065

Exhibit 7.3a: Estimated Refinery Energy Use by Crude Oil, PADD 2

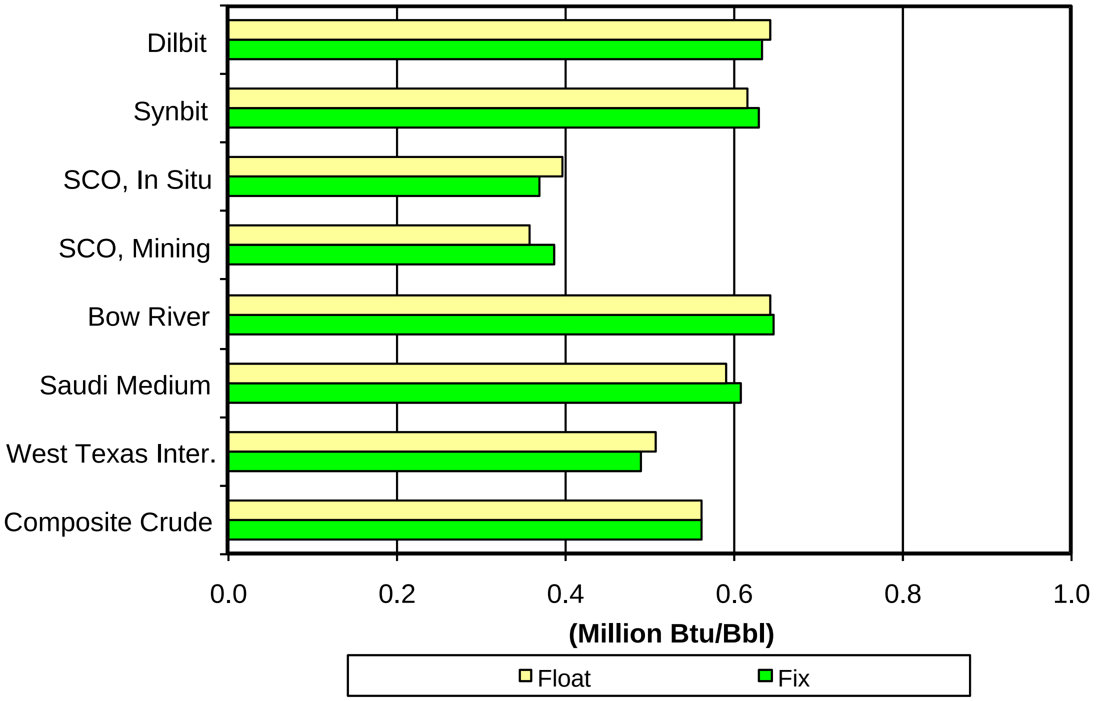


Exhibit 7.3b: Estimated Refinery CO2 Emissions by Crude Oil, PADD 2

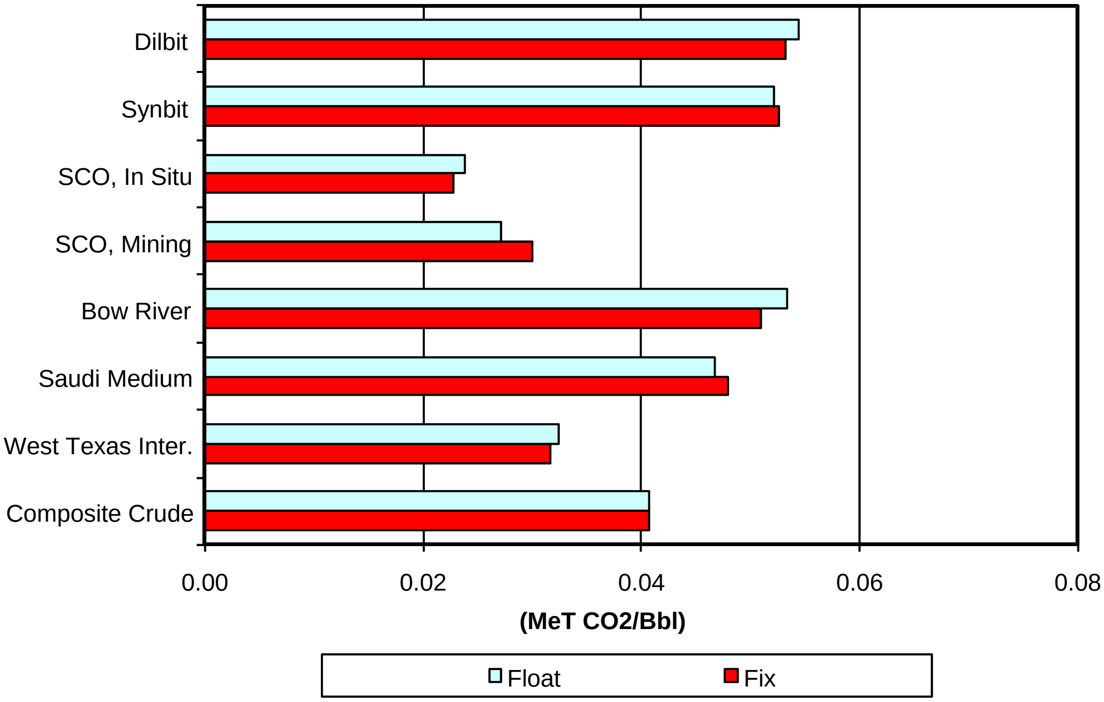


Exhibit 7.4a: Estimated Refinery Energy Use by Crude Oil, PADD 3

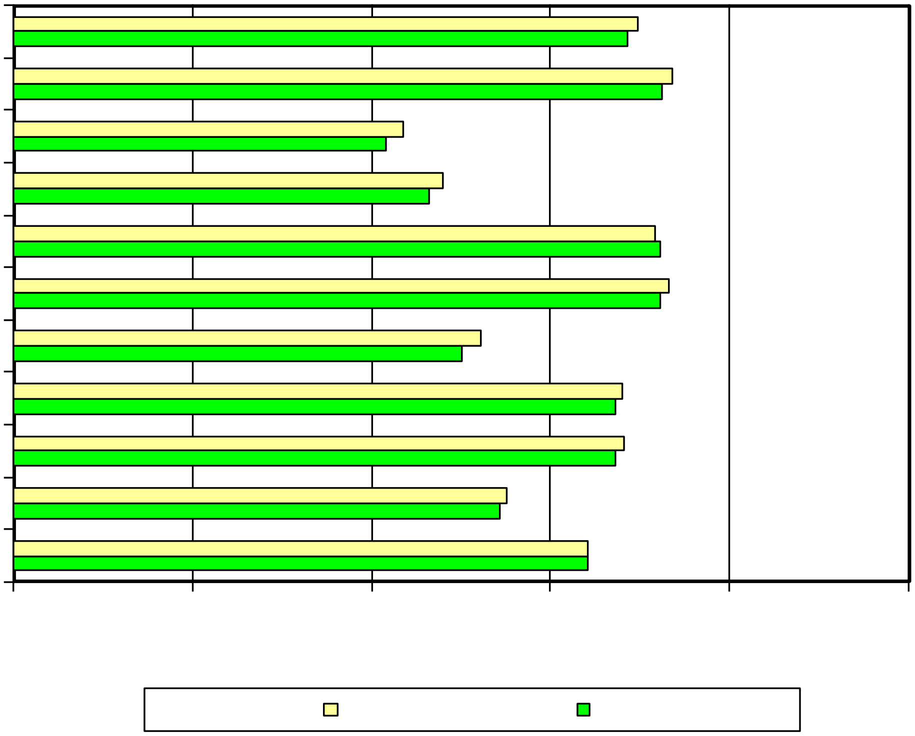


Exhibit 7.4b: Estimated Refinery CO2 Emissions by Crude Oil, PADD 3

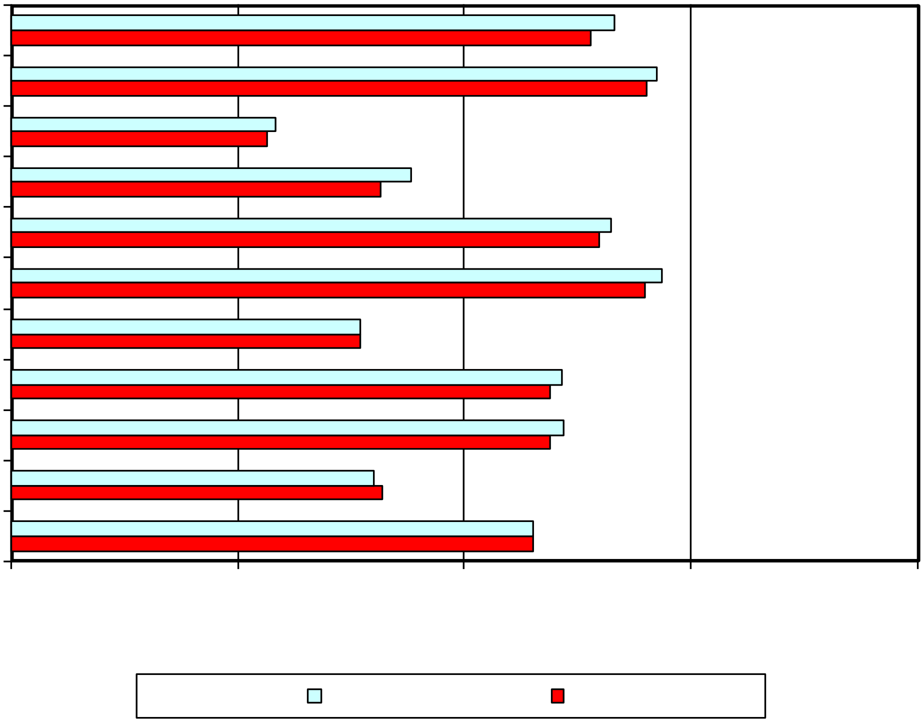


Exhibit 7.5a: Estimated Refinery Energy Use by Crude Oil, California

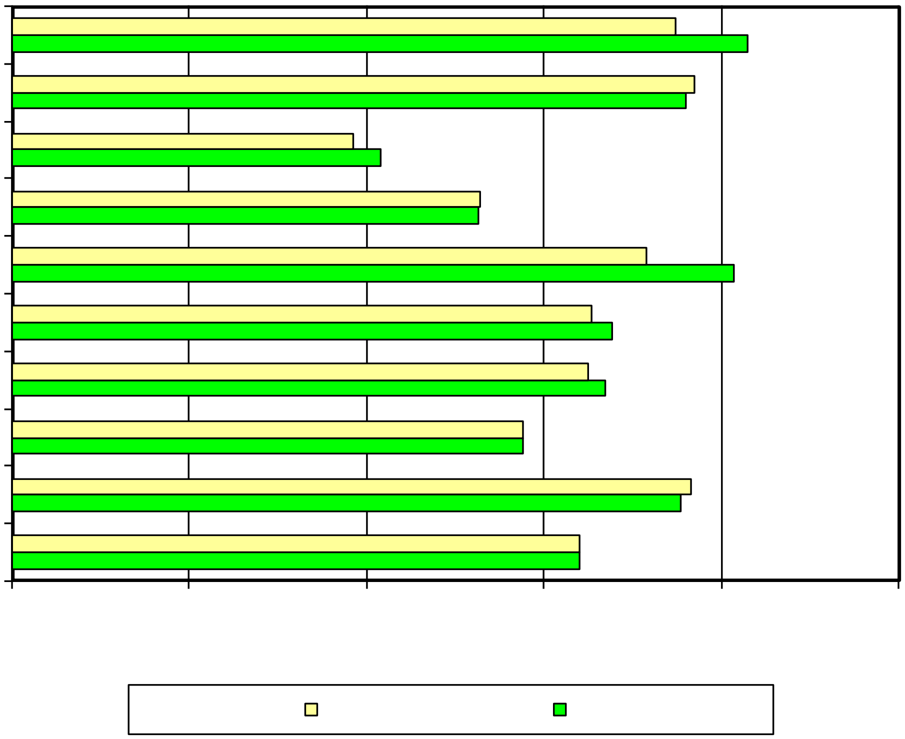
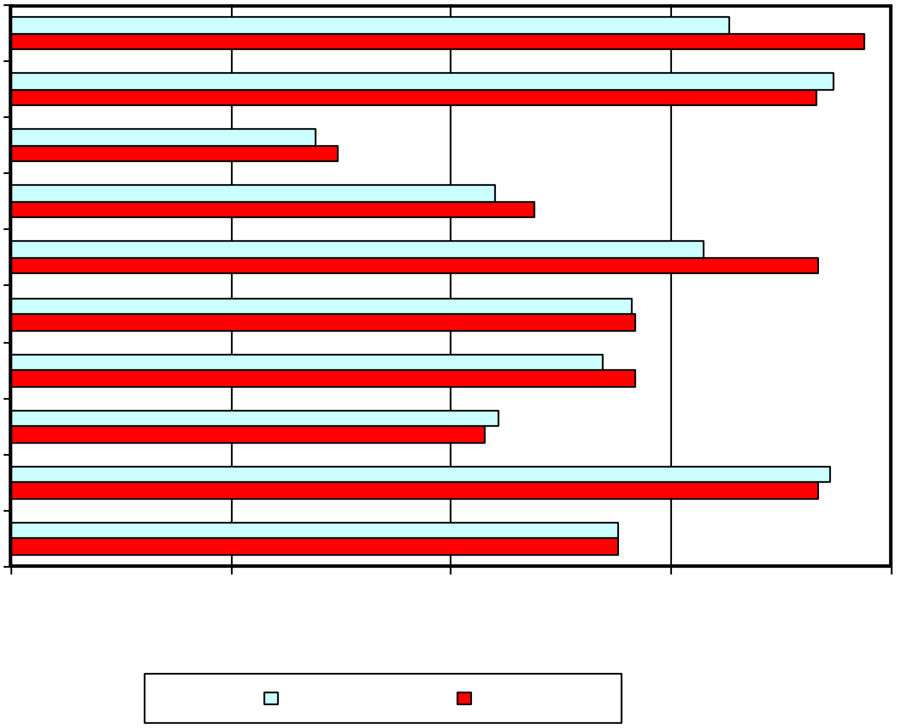


Exhibit 7.5b: Estimated Refinery CO2 Emissions by Crude Oil, California



7.2.1 Estimated Refinery Energy Use, by Crude Oil and Region

The estimates shown in these exhibits indicate that:

- For a given crude oil/region combination, the FIX and FLOAT cases yield similar (but not identical) results. The differences between FIX and FLOAT pairs vary, in both magnitude and direction, from one crude oil/region combination to another. See, for example, the estimates for Maya and Dilbit in Exhibit 7.2.

  Differences between FIX and FLOAT pairs for a given crude oil indicate different region-to-region differences in the optimal refinery processing response to an incremental volume of the given crude in the overall crude slate.

- Current refinery energy use in the U.S., indicated by the *Composite Crude* estimates (obtained from the baseline cases) is in the range of 0.56–0.64 M BTU/Bbl, or about 9½–11% of the energy content of the crude oil.

  Refinery energy use is higher in PADD 3 and California than in PADD 2, primarily because the crude slates in PADD 3 and California contain proportionately more heavy, sour crude (such as Bachaquero 17, Maya, and SJV Heavy) than the crude slate in PADD 2. Correspondingly, PADD 2 refineries are less complex (that is, have relatively less conversion process capacity) than PADD 3 and California refineries. PADD 2 refineries also produce a product slate with relatively less jet fuel, lube oils, and petrochemical feedstocks.

- The refinery energy use associated with conventional light, sweet crudes (WTI, Escravos) is roughly 2/3 the energy use associated with the heaviest conventional sour crudes (SJV Heavy, Maya, Bachaquero 17). For example, in PADD 3, estimated refinery energy use is 0.50–0.54 M BTU/Bbl for Escravos and WTI and 0.72–0.73 M BTU/Bbl for Maya and Bachaquero 17.

  These intra-regional differences indicate the effects of crude oil properties on refinery energy use (all else equal).

- For a given crude oil, refinery energy use varies from region to region. For example, the refinery energy use for Saudi Medium ranges from about 0.59–0.61 M BTU/Bbl in PADD 2 to about 0.67–0.68 BTU/Bbl in PADD 3; the refinery energy use for SCO (in situ) ranges from 0.36–0.39 MM BTU/Bbl in PADD 2 to 0.42– 0.44 M BTU/Bbl in PADD 3.

  These inter-regional differences for a given crude oil indicate the effects on refinery energy use of baseline crude slate, refinery capital stock, and (to a lesser extent) regional standards on refined product emissions performance.

- In general, the estimated refinery energy use associated with the Canadian Synbit and Dilbit crudes is comparable to that of the conventional heavy, sour crudes (e.g., Maya, Bachaquero 17, and SJV Heavy).

The estimated refinery energy use for SCO (from both mined and in situ bitumen) is less than that for any conventional crude oil considered, primarily because (by virtue of the upgrading processes that produce them) the SCOs have low sulfur content and no vacuum resid fraction. We assumed in the analysis that refineries running SCO would use processing schemes that fully exploit these properties.

7.2.2 Estimated Refinery CO_2 Emissions, by Crude Oil and Region

The estimates shown in Exhibits 7.2–7.5 indicate that:

- The differences in estimated refinery CO_2 emissions between FIX and FLOAT pairs track the differences in estimated refinery energy use between the same pairs.

- Current refinery CO_2 emissions in the U.S., indicated by the *Composite Crude* estimates (obtained from the baseline cases) are in the range of 0.041–0.055 MeT/Bbl.

  Refinery CO_2 emissions are highest in California, because of the high proportion of heavy, sour crude in the California crude slate, the unusual product slate in California (little or no residual oil production), and the state's stringent standards on gasoline and diesel quality.

- For the various crude oil/region combinations, estimated refinery CO_2 emissions track estimated refinery energy use.

  Crude oils with the highest refinery energy use have the highest refinery CO_2 emissions (SJV Heavy, Maya, Bachaquero 17, Synbit, and Dilbit). The SCOs have the lowest refinery CO_2 emissions.

- In general, the estimated refinery CO_2 emissions associated with Canadian Synbit and Dilbit crudes is comparable to those of the conventional heavy, sour crudes (e.g., Maya, Bachaquero 17, and SJV Heavy). The estimated refinery CO_2 emissions for SCO (from both mined and in situ bitumen) are lower than those for any conventional crude oil considered.

8. ADDITIONAL COMMENTS

8.1 Interpreting the Refinery Energy Use and CO_2 Emissions Estimates

The results of our analysis should be interpreted as estimates of the refinery energy use and CO_2 emissions associated with a given crude oil when a small volume of it is introduced into a particular refining region's crude slate.

The energy required to refine a crude oil is not a fixed, intrinsic property of the crude. In practice, a crude oil's refinery energy use and the resulting CO_2 emissions depend not only on the crude's properties but also, to some degree, on the specific refining environment in which the crude is processed.

Our analytical approach recognizes differences in the regional refining environments in which the various crudes are used (i.e., the rest of the crude slate, refinery configuration, product slate, etc.). Accordingly, for a given crude oil, the analysis yields somewhat different results from region to region, as well as different results in corresponding pairs of FIX and FLOAT cases (as shown in Exhibit 7.2).

The methodology produces such estimates because, through its use of refinery LP modeling, it recognizes the (albeit limited) flexibility in regional refining operations to accommodate changes in crude slate and respond to economic driving forces.

8.2 Refinery Energy Use in the U.S. and Elsewhere

The U.S. refining sector is unlike any other, and its special characteristics exert a strong influence on the results. Hence, the results apply specifically to the U.S. refining sector.

U.S. refineries turn out a product slate with the world's highest proportion of transportation fuels – and of gasoline in particular. The gasoline output of U.S. refineries is about 50 vol% on crude, more than double the world average, and gasoline is the main "on purpose" product of U.S. refineries. Accordingly, U.S. refineries perform extensive processing and upgrading of crude oil fractions and conversion of the heaviest crude oil fractions into lighter, higher-valued products (of which gasoline is the largest component).

European refineries, by contrast, turn out less gasoline, more diesel fuel, and more resid per barrel of crude than U.S. refineries. The main "on purpose" product of European refineries is diesel fuel; gasoline is in large measure a co-product. (Indeed, much of the gasoline output of European refineries is surplus to local demand and is exported.) European refineries have much less conversion capacity, relative to crude throughput, than U.S. refineries. Consequently, we expect that this analysis would yield different results if were applied to the European refining sector.

8.3 Assumed Primary Fuels Mix for Purchased Power

As indicated in Section 5, we assumed that the primary fuel sourcing for purchased electricity was 50% coal/30% natural gas/20% nuclear and renewables– approximately the U.S. average – for all regions. Changes in this assumption would affect the results of the analysis: a higher (lower) coal share would lead to higher (lower) estimates of refinery energy use and CO_2 emissions. However, the effect of any such change on the results of the analysis would be small because purchased electricity constitutes a relatively small share of total refinery energy use.

Exhibit A-1: Estimated Aggregate Petroleum Refining Capacity, 2006

(K bbl/calendar day, except as noted)

Type of Process	Process	PADD		California	Total U.S.
		2	3		
Crude Distillation	Atmospheric	3,554	8,390	1,898	17,275
	Vacuum	1,503	3,815	1,103	7,710
Conversion	Coking				
	Delayed	358	1,168	339	2,039
	Fluid	16	63	98	243
	Other		39	22	61
	Fluid Cat Cracking	1,165	2,937	665	5,809
	Hydrocracking				
	Distillate	160	575	358	1,213
	Resid		102		141
	Lube		46	32	78
	Other	33		65	98
	Visbreaking			10	22
	Thermal Cracking		10		10
Upgrading	Alkylation	251	581	175	1,182
	Pen/Hex Isomerization	172	233	108	543
	Reforming	840	1,718	415	3,571
	Low Pressure	285	694	84	1,155
	All Other	554	1,024	332	2,416
	Polymerization	5	15	7	54
	Dimersol	3	7	6	17
Ether Production	MTBE	4	27	3	37
	TAME		3		3
Hydrotreating	Naphtha Feed	1,035	2,238	432	4,394
	Naphtha/Aromatics Sat.	10	11	22	43
	FCC Naphtha	332	1,083	128	1,948
	Kerosene & Distillate	1,067	2,213	490	4,557
	Distillate/Aromatics Sat.	18	26	65	133
	FCC Feed/Heavy Gas Oil	524	1,279	593	2,539
	Resid		316		326
	Lube Oil	24	89	33	146
	Other	3	224	67	321
Other	BTX Plant	50	233		326
	Other Aromatics	8	46		66
	Butane Isomerization	24	109	65	262
	Hydrogen (MM scf/d)				
	Production	634	998	1,253	3,233
	Recovery	161	655	92	1,049
	Lube Oil	17	148	20	204
	Solvent Deasphalting	16	200	59	330
	Coke (K t/d)	20	70	21	123
	Sulfur Recovery (K Sh t/d)	5.2	19.4	4.1	31
	Asphalt	245	125	42	506
Complexity		9.7	10.5	13.4	10.1

1 Includes production and recovery.

Sources: Capacity derived from "2006 Worldwide Refinery Survey," *Oil & Gas Journal*, Dec. 18, 2006;and
DOE 2006 Refinery Capacity Survey (DOE website).
Generalized Complexity Index Scores: *Oil & Gas Journal*, March 18, 1996, p. 74-80.

Exhibit A-2: Derived Distillation Curves and Whole Crude Properties for Regional Composite Crude Oils

Fractions & Properties	PADD		Calif	U.S.
	2	3		
Volume (K b/d)	3,297	7,260	1,798	15,242
CRUDE FRACTIONS				
LPGs:				
Ethane	0.001	0.001	0.001	0.001
Propane	0.003	0.004	0.003	0.003
Isobutane	0.003	0.003	0.003	0.003
Butane	0.010	0.009	0.010	0.011
Naphthas:				
Very Light (C5-160)	0.047	0.046	0.032	0.046
Light (160-250)	0.081	0.071	0.059	0.074
Medium (250-325)	0.074	0.066	0.053	0.068
Heavy (325-375)	0.048	0.046	0.035	0.046
Middle Distillates:				
Kerosene (375-500)	0.127	0.122	0.104	0.121
Distillate (500-620)	0.122	0.119	0.114	0.120
Atmospheric Resid:				
Light gas oil (620-800)	0.162	0.158	0.167	0.162
Heavy gas oil (800-1050)	0.170	0.167	0.199	0.172
Resid (1050+)	0.063	0.055	0.088	0.070
Asphalt (1050+)	0.089	0.132	0.132	0.104
Total:	1.000	1.000	1.000	1.000
WHOLE CRUDE				
API Gravity	32.1	29.8	25.5	30.4
Sulfur (wt %)	1.35%	1.64%	1.50%	1.42%
Utilities				
Fuel (foeb/b)	0.015	0.014	0.014	0.014
Steam (lb/b)	33.3	32.6	32.2	32.9
Electricity (kWh/b)	0.85	0.85	0.88	0.85

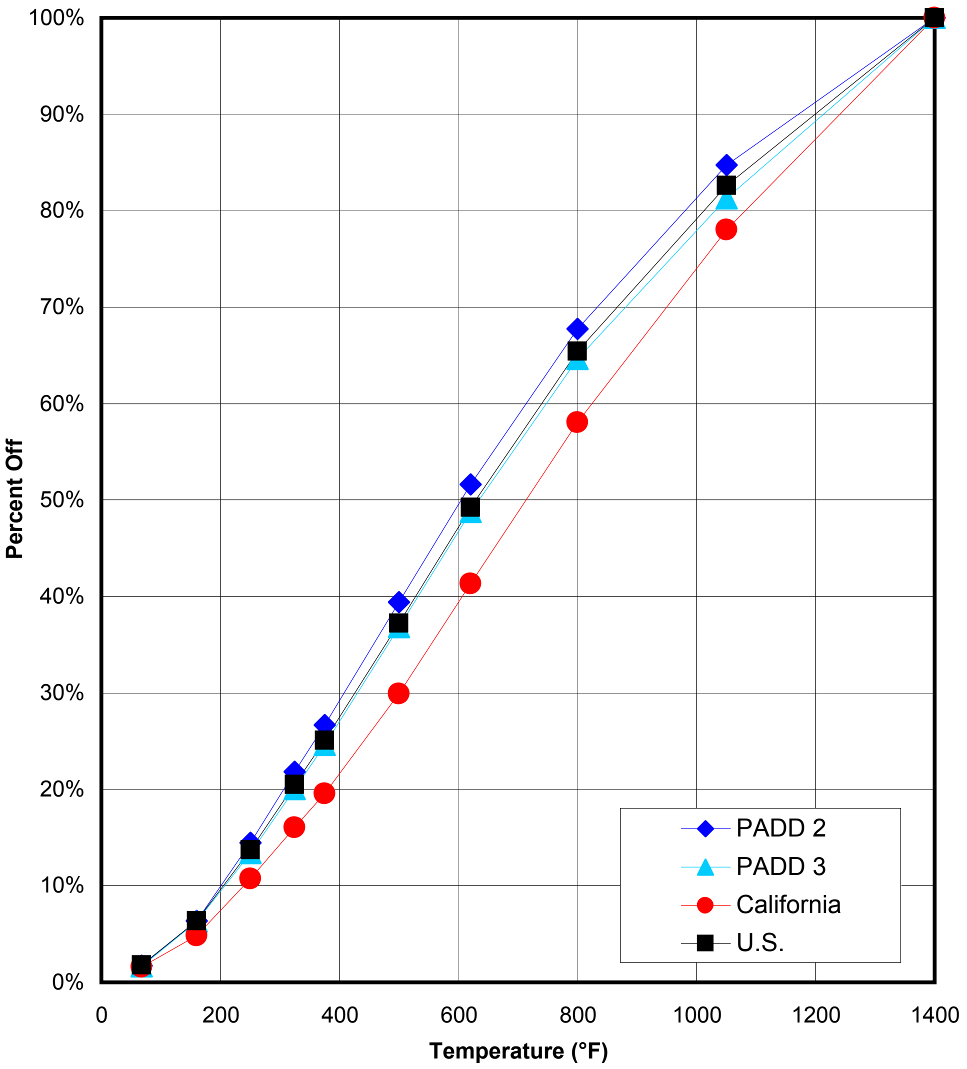


Exhibit A-3a: Refinery Net Inputs, by Region, 2006
(K b/d)

	U.S.	PADD 2	PADD 3	California[1]
Net Inputs	**16,690**	**3,519**	**8,050**	**1,994**
Crude Oil	**15,242**	**3,297**	**7,260**	**1,798**
Natural Gas Liquids and LPG	**427**	**104**	**246**	**18**
Pentanes Plus	183	59	99	14
Liquified Petroleum Gases	244	45	147	4
Normal Butane-Butylene	61	4	44	0
Isobutane-Isobutylene	183	41	103	4
Other Liquids	**1,021**	**119**	**544**	**178**
Other Hydrocarbons/Oxygenates	360	70	138	57
Other Hydrocarbons-Hydrogen	91	12	50	0
Oxygenates[2]	269	59	88	57
Fuel Ethanol	241	59	71	57
MTBE	28		17	0
Other	0		0	
Unfinished Oils	661	48	405	105
Naphtha and Lighter	116	25	72	8
Kerosene and Light Oils	-53	9	-62	0
Heavy Gas Oils	442	31	285	94
Residuum	157	-16	110	2
Gasoline Blending Components				16
Av-Gas Components	0	0	0	0
Process Feeds (K b/d)				
Catalytic Cracking	5,233	1,066	2,615	0
Catalytic Hydrocracking	1,268	191	519	0
Delayed and Fluid Coking	2,085	305	1,173	0
Crude Oil Properties				
API Gravity (degrees)	30.4	32.0	30.1	25.6
Sulfur Content (avg wt%)	1.41	1.34	1.64	1.44

1 Estimated

2 Estimated oxgenate volumes correspond to production of RBOBs, CBOBs, and finished oxygenated gasoline.

Note: Negative numbers indicate net production.

Sources: Derived from (1) refinery input data provided by EIA Website; (2) *California Weekly Fuels Reports, 2006; and (3)* CEC *Refinery Reports, 2004 & 2005.*

Exhibit A-3b: Refinery Outputs, by Region 2006
(K b/d)

	U.S.	PADD 2	PADD 3	California[1]
Crude Oil and Petroleum Products[1]	**16,159**	**3,432**	**7,746**	**1,902**
Liquified Petroleum Gases	**562**	**107**	**348**	**50**
Ethane-Ethylene	19		18	0
Ethane	14		14	0
Ethylene	4		4	0
Propane/Propylene	543	107	330	40
Propane	302	72	150	33
Propylene	241	34	180	7
Normal Butane/Butylene	0	0	0	10
Isobutane/Isobutylene	0	0	0	0
Finished Refined Products[2]	**15,598**	**3,325**	**7,398**	**1,852**
Finished Gasoline Outputs[3]	8,173	1,853	3,744	1,100
Reformulated Motor Gasoline	2,644	292	824	1,023
with Ether	242		150	1
with Alcohol	2,351	292	665	982
Non-Oxygenated	51		10	40
Conventional Motor Gasoline	5,528	1,560	2,919	77
with Alcohol	490	294	44	11
Other	5,038	1,267	2,876	66
Aviation Gasoline	18	4	12	0
Kerosene-Type Jet Fuel	1,481	208	747	253
Kerosene	47	12	27	0
Distillate	4,040	914	1,928	356
0-15 ppm Sulfur	1,243	402	595	0
15-500 ppm Sulfur	1,577	385	844	132
> 500 ppm Sulfur	941	127	489	3
CARB Diesel	279	0	0	220
Residual Fuel Oil	635	55	292	65
0-0.3 Sulfur	84	0	29	3
0.31-1.0 Sulfur	150	6	32	21
Greater Than 1% Sulfur	402	50	231	42
Pet Chem Feedstocks	394	36	329	10
Naphtha	196	30	147	0
Other Oils	198	6	182	10
Special Naphtha	36	6	28	0
Lubes	183	16	131	19
Waxes	15	3	10	0
Petroleum Coke	848	146	475	141
Marketable	601	100	350	110
Catalyst	247	45	124	31
Asphalt and Road Oil	506	205	112	39
Still Gas	709	138	349	109
Miscellaneous	71	16	38	13
Fuel Use	2		0	2
Nonfuel Use	69	16	38	11
Processing Gain	-994	-196	-519	

1 Estimated

2 Excludes petroleum coke, still gas, and miscellaneous fuel use

3 Includes RBOB and CBOB volumes and associated oxygenate volumes.

Sources: Derived from (1) refinery output data provided by EIA Website; (2) *California Weekly Fuels Reports, 2006; and (3)* CEC *Refinery Report, 2006*

Exhibit A-3c: Projected Refinery Net Inputs, by Region, 2015
(K b/d)

	U.S.	PADD 2	PADD 3	California
Net Inputs	**2,013**	**510**	**980**	**241**
Crude Oil	**-**	**-**	**-**	**-**
Natural Gas Liquids and LPG	**403**	**98**	**232**	**17**
Pentanes Plus	173	56	93	13
Liquified Petroleum Gases	230	42	139	4
Normal Butane-Butylene	58	4	42	0
Isobutane-Isobutylene	172	38	98	4
Other Liquids (ex H2 & nat. gas)	**1610**	**411**	**748**	**225**
Fuel Ethanol[1]	1011	368	381	114
Unfinished Oils	599	44	367	95
Naphtha and Lighter	105	22	65	7
Kerosene and Light Oils	-48	8	-56	0
Heavy Gas Oils	400	28	259	86
Residuum	142	-14	100	2
Gasoline Blending Components				16
Av-Gas Components	0			

[1] Estimated ethanol volumes correspond to projected production of finished gasoline (blended with 10% ethanol) and of E85.

Note: Negative numbers indicate net production.

Sources: Derived from Exhibit A3a and *Annual Energy Outlook 2009 (Early Release)*, DOE/EIA.

Exhibit A-3d: Projected Refinery Outputs, by Region 2015
(K b/d)

	U.S.	PADD 2	PADD 3	California
Crude Oil and Petroleum Products[1]	**16,302**	**3,623**	**7,660**	**1,963**
Liquified Petroleum Gases	**541**	**103**	**332**	**41**
Ethane-Ethylene	19		18	0
Ethane	14		14	0
Ethylene	4		4	0
Propane/Propylene	522	103	314	41
Propane	290	70	143	33
Propylene	232	33	171	7
Finished Refined Products[1]	**15,761**	**3,520**	**7,328**	**1,922**
E85	233	233		
Finished Gasoline Outputs[2]	8286	1855	3807	1137
Reformulated Motor Gasoline	2757	274	771	1057
with Alcohol	2757	274	771	1057
Non-Oxygenated	-	-	-	-
Conventional Motor Gasoline	5530	1537	3036	80
with Alcohol	5530	1537	3036	80
Other	-	-	-	-
Aviation Gasoline	18	4	12	0
Kerosene-Type Jet Fuel	1,326	181	652	254
Kerosene	47	12	27	0
Distillate	4,142	928	1958	399
0-15 ppm Sulfur	3,538	928	1958	
15-500 ppm Sulfur				
> 500 ppm Sulfur	194			
CARB Diesel	410			399
Residual Fuel Oil	620	55	289	56
0-0.3 Sulfur	82	0	29	2
0.31-1.0 Sulfur	146	6	32	18
Greater Than 1% Sulfur	392	49	229	36
Pet Chem Feedstocks	335	31	279	8
Naphtha	196	30	147	
Other Oils	139	4	126	8
Special Naphtha	31	5	24	0
Lubes	183	16	131	19
Waxes	15	3	10	0
Asphalt and Road Oil	455	183	101	38
Miscellaneous	69	16	38	11
Fuel Use	-	-	-	-
Nonfuel Use	69	16	38	11

1 Excludes petroleum coke, still gas, and miscellaneous fuel use

2 Includes RBOB and CBOB volumes and associated oxygenate volumes.

Sources: Derived from Exhibit A3b and *Annual Energy Outlook 2009 (Early Release)*, DOE/EIA.

Exhibit A-4: Selected Refined Product Properties, by Region

Refined Product	Property	U.S.		PADD 2		PADD 3		California	
		2006	2015	2006	2015	2006	2015	2006	2015
Gasoline									
Conventional	Octane ((R+M)/2)[1]	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0
	Oxygen (wt%)[2]	0.3		0.7		0.2		0.5	
	RVP (psi)[3]	10.9	10.9	11.4	11.4	10.8	10.8	11.0	11.0
	Benzene (vol%)[4]	1.11	<0.62	1.20	<0.62	1.11	<0.62	0.60	<0.62
	Sulfur (ppm)[4]	113	<30	55	<30	55	<30	~23	<30
	Ethanol (vol%)		10%		10%		10%		10%
Reformulated	Octane ((R+M)/2)[1]	88.0	88.0	88.0	88.0	88.0	88.0		
	Oxygen (wt%)[2]	3.2		3.3		3.1			
	RVP (psi)[3]	10.4	10.4	10.6	10.6	10.4	10.4		
	Benzene (vol%)[4]	0.59	<0.62	0.80	<0.62	0.58	<0.62		
	Sulfur (ppm)[4]	80	<30	45	<30	45	<30		
	Ethanol (vol%)		10%		10%		10%		10%
California RFG	Octane ((R+M)/2)[1]							87.5	87.5
	Oxygen (wt%)[2]							2.0	
	RVP (psi)[3]							8.7	0.0
	Benzene (vol%)[4]							0.55	<0.62
	Sulfur (ppm)[4]							13	~6
	Ethanol (vol%)								10%
E85	Octane ((R+M)/2)				-				
	Oxygen (wt%)								
	RVP (psi)				<11				
	Benzene (vol%)				<0.62				
	Sulfur (ppm)				<30				
	Ethanol (vol%)				<85%				
Diesel Fuel									
EPA Diesel	Cetane Number	>40		>40		>40		>40	
	Sulfur (ppm)	<500		<500		<500		<500	
Low Sulfur Diesel	Cetane Number	>40	>40	>40	>40	>40	>40		
	Sulfur (ppm)	<15	<15	<15	<15	<15	<15		
CARB Diesel	Cetane Number[3]							~49	~49
	Sulfur (ppm)[3]							<5	<5

1 Approximate average of regular and premium grades.
2 Approximate average for 2006.
3 Year-round average.
4 Approximate average for 2006; maximum for 2015.

Exhibit B-1: Refinery Inputs and Outputs for Calibration and Reference Cases
(K b/d)

Inputs & Outputs	U.S.		PADD 2		PADD 3		California	
	Calibration 2006	Reference 2015	Calibration 2006	Reference 2015	Calibration 2006	Reference 2015	Calibration 2006	Reference 2015
Inputs								
Crude Oil	15,045	14,345	3,277	3,087	7,253	6,859	1,700	1,695
Iso-butane			41	38	58		0	22
Butane	61		4	4	44	36		
Gas Oils	442	400	31	28	285	259	94	86
Residuum	157	142			110	100	2	2
Outputs[1]								
Aromatics	232	232	33	33	166	167		
Ethane	19	19			18	18		
Propane	302	270	72	63	150	137	33	28
Propylene	241	232	34	33	180	171	7	7
Aviation Gas	18	18	4	4	12	12		
Naphthas	36	31	6	5	28	24		
CBOBs & RBOBs[2]	7,653	7,249	1,731	1,622	3,493	3,268	1,007	994
Jet Fuel[2]	1,510	1,366	195	171	809	715	245	247
Diesel Fuel[2]	4,040	4,142	905	920	1,928	1,958	355	399
Unfinished Oils	267	208	22	20	219	163	21	20
Residual Oil	626	520	72	69	292	290	66	56
Asphalt	506	455	205	183	112	101	39	38
Lubes & Waxes	198	198	19	19	141	141	19	19
Marketable Coke	601	597	100	88	350	298	110	112

[1] Excludes marketable coke.

[2] Gasoline, jet fuel, and diesel fuel volumes are net of purchased blendstocks.

Exhibit B-2: Process Capacity Use and Operating Severities, by Region
(K b/d except as noted)

Type of Process	Process	PADD 2 Calibration 2006	PADD 2 Reference 2015	PADD 3 Calibration 2006	PADD 3 Reference 2015	California Calibration 2006	California Reference 2015
Capacity Use							
Crude Distillation	Atmospheric	3,277	3,087	7,253	6,859	1,700	1,695
	Vacuum	1,585	1,493	3,714	3,513	997	994
Conversion	Fluid Cat Cracking	1,091	971	2,480	2,263	576	511
	Hydrocracking	193	193	500	575	355	355
	Resid Processing[1]	315	303	1,346	1,277	434	440
Upgrading	Alkylation[2 3]	221	233	468	478	179	178
	Pen/Hex Isomerization[3]	172	172	233	233	108	108
	Reforming	585	540	1,227	1,033	344	316
Hydrotreating	Naphtha[4]	971	1,112	2,040	2,797	477	514
	Distillate	985	1,064	1,950	2,200	379	425
	Gas Oil	491	437	1,079	984	576	511
	Resid				73		
Other	Aromatics[3]	30	37	147	148		
	Butane Isomerization[3]		24		50	29	15
	Ethers[3]			30			
	Hydrogen (MM scf/d)[3]	27	35	79	94	61	62
	Lube Plant[3]	19	19	141	141	19	19
	Splitting	319	259	985	1,063	725	543
	Sulfur Plant (K T/d)[3]	4	3	11	10	3	3
Operations							
FCC	Conversion (%)	78.4	78.0	77.7	78.2	78.3	77.4
Reforming	Severity ((R+M)/2)	99.1	93.5	100.0	98.3	97.1	89.5

1 Includes coking, visbreaking, and solvent deasphalting.
2 Includes alkylation, polymerization, and dimersol.
3 Volumes reflect product output
4 Includes FCC naphtha desulfurization

Exhibit C-1a: Reported and Modeled Energy Use and Normalization Factors for U.S. Model

Fuel Type	DOE 2006		Refinery Model Baseline 2006	Normalization Factor
	Reported	Revised		
Refinery Gases and Natural Gas (K foeb/d)[1]	989	966	826	117%
Catalyst Coke (K b/d)	247	247	239	103%
Power (MM Kwh/d)	108	153	97	158%
Other (K foeb/d)	23			

Exhibit C-1b: Reported and Modeled Refinery Energy and Normalization Factors for Regional Models

	PADD 2				PADD 3				California			
			Refinery Model				Refinery Model				Refinery Model	
	DOE 2006		Baseline	Projected	DOE 2006		Baseline	Projected	CEC 2006		Baseline	Projected
	Reported	Revised	2006	2015	Reported	Revised	2006	2015	Reported	Revised	2006	2015
Refinery Fuel Use												
Refinery Gases and Natural Gas (K foeb/d)[1 2]												
Refinery Use	185	191	158	155	516	499	405	401	158	134	126	124
Natural Gas for Power Generation (est)	*3*				*45*				*31*			
Catalyst Coke (K b/d)	45	45	52	46	124	124	114	109	32	32	24	22
Power (MM Kwh/d)												
Refinery Use		31	19	19		77	46	49		21	16	16
Puchased	29	29			51	51			9	9		
Refinery Generated Power	2.2				32.9				23			
For Refinery Use	2.2	2.2			26.3	26			12.4	12.4		
Sale to Grid	0.0				6.6				10.4			
Purchased Steam (MM lbs/d)	20	-			107	-			35			
Other (K foeb/d)	5	-			5	-			0.4			
Hyrogen Production (MM scf/d)		414	414	574		998	998	1,315		1,194	1,194	1,207
Crude Oil Input (K b/d)	**3,312**	**3,312**	**3,308**	**3,115**	**7,655**	**7,655**	**7,648**	**7,219**	**1,895**	**1,895**	**1,796**	**1,783**
Net Product Volumes (K b/d)[3]	**3,281**	**3,281**	**3,287**	**3,132**	**7,550**	**7,550**	**7,548**	**7,166**	**1,807**	**1,807**	**1,792**	**1,808**
Gasoline, CBOBs, & RBOBs[4]			1,764	1,655			3,659	3,435			1,007	994
Jet Fuel, Diesel Fuel, and Home Heating Oil[5]			1,100	1,091			2,737	2,673			600	646
All Other			422	386			1,153	1,057			185	168
Refinery Energy Use (Billion btu/d)												
Total -- excL. natural gas to H2 (billion btu/d)[6]	1,781	1,784	1,489	1,439	4,677	4,624	3,671	3,646	1,323	1,235	1,088	1,058
Per barrel energy use (MM btu/b input)												
DOE	0.538	0.539			0.611	0.604			0.698	0.652		
As Represented in ARMS			0.450	0.462			0.480	0.505			0.606	0.593
Calibrated to adjusted DOE Energy Use			0.539	0.553			0.604	0.636			0.652	0.639
Average Electricity Conv. Factor (MM btu)		9.87	9.87	9.87		9.48	9.48	9.48		9.13	9.13	9.13
Normalization Factors												
Refinery Energy Use			120%				126%				108%	
Volume of Refinery Gases & Natural Gas Use			121%				123%				101%	
Volume of Catalyst Coke Burned			88%				109%				128%	
Volume of Electricity Use			164%				168%				123%	

Notes: All steam in the refinery model is refinery-generated; the associated energy use is incorportated in refinery gases and natural gas burned as fuel.
Power generation efficiency is assumed to be 40%, which results in a conversion factor of 8.53 (3.412/40%) btu/Kwh.

1 Includes all refinery gases burned as fuel and purchased natural gas used for fuel.

2 Still gas, as reported by DOE, contains 6.0 MM btu/foeb; we convert still gas volumes into a standard foeb of 6.3 mm btus.

3 DOE product volume excludes still gas, marketable & catalyst coke, ethanol blended in gasoline, net purchases of pentanes, normal butane, and other gasoline blendstocks, and net purchases of naphtha and distillate unfinished oils.

4 Excludes: (1) ethanol in finished gasoline or E85 and (2) net purchases of other gasoline blendstocks; includes BTX production and petroleum components of E85.

5 Exludes net purchases of jet fuel blendstocks.

6 For DOE 2006, excludes small volumes of distillate, resid, marketable coke, other products, and coal that may have been used for fuel.

Sources: Refinery Fuel Use -- DOE Website; power generation -- Table 24, "Supplemental Tables," *Annual Energy Outlook 2008* , DOE/EIA; and modeling results from ARMS.

Exhibit C-2: Allocation of Refinery Energy Use and CO2 Emissions to Refined Products for U.S.: Additional Detail

	DOE 2006		Baseline	Projected 2015				
				New Stds	Refined Product Scenario			
	Reported	Revised	2006	& RFS2	Gasoline[7]	Jet Fuel	Diesel	Other
Refinery Fuel Use								
Refinery Gases and Natural Gas (K foeb/d)[1]	989							
Refinery Use		966	966	953	948	952	951	953
Natural Gas	334	311	311	346	348	346	344	345
Still Gas	655	655	655	607	600	607	607	608
Natural Gas for Power Generation (est)	*85*							
Catalyst Coke (K b/d)	247	247	247	231	227	231	231	231
Power (MM Kwh/d)								
Refinery Use		153	153	156	155	156	156	156
Puchased	107.8	107.8						
Refinery Generated Power	62.8							
For Refinery Use	44.9	45						
Sale to Grid	17.9	-						
Purchased Steam (MM lbs/d)	194	-						
Other (K foeb/d)	23	-						
Hyrogen Production (MM scf/d)[2]		2,676	2,676	3,173	3,160	3,167	3,163	3,176
Product Volumes (K b/d)[3]	**15,645**	**15,645**	**15,647**	**14,939**	**14,859**	**14,925**	**14,896**	**14,927**
Gasoline, CBOBs, & RBOBs[4]			8,180	7,762	7,681	7,762	7,762	7,762
Jet Fuel[5]			1,510	1,366	1,366	1,352	1,366	1,366
Diesel Fuel, Home Heating Oil & Lubes[6]			4,238	4,340	4,340	4,340	4,297	4,340
All Other (ex coke)			1,719	1,472	1,471	1,472	1,472	1,460
Crude Oil Input (K b/d)[7]	**15,841**	**15,841**	**15,644**	**14,887**	**14,802**	**14,873**	**14,842**	**14,877**
Refinery Energy Use (Billion btu/d)								
Total, excluding natural gas for H2 (billion btu/d)[8]	9,253	9,100	9,100	8,948	8,881	8,942	8,934	8,948
Change from baseline (billlion btu/d)					-67.7	-6.6	-13.9	-0.1
Percent allocation by refined product					77%	7%	16%	0%
Per barrel energy use (MM btu/b)	0.591	0.582	0.582	0.599	0.884	0.487	0.325	0.004
CO2 Emissions (K MT/d)								
Total		660.7	660.7	654.0	648.5	653.5	653.1	654.2
Fuel, Catalyst Coke & Power		612.5	612.5	596.8	591.5	596.4	596.1	596.9
Hydrogen Production		48.2	48.2	57.2	57.0	57.1	57.0	57.3
Change from baseline (K MT/d)					-5.5	-0.5	-0.9	0.1
Percent allocation by refined product					81%	8%	13%	-2%
Per barrel CO2 emissions (MT/b)			0.042	0.044	0.068	0.037	0.020	*0.000*

Notes: All steam in the refinery model is refinery-generated; the associated energy use is incorportated in refinery gases and natural gas burned as fuel.
Power generation efficiency is assumed to be 40%, which results in a conversion factor of 8.53 (3.412/40%) btu/Kwh.

1 Includes all refinery gases burned as fuel and purchased natural gas used for fuel; 6.3 MM btu/foeb

2 DOE ostensibly reports hydrogen purchases in the "other hydrocarbons-hydrogen" category, but does not report on-purpose hydrogen production. We assume combined baseline hydrogen purchases and on-purpose hydrogen production equals our modeled volume of on-purpose hydrogen production.

3 DOE product volume excludes still gas, coke, ethanol blended in gasoline, net purchases of other gasoline blendstocks (including C4s), and net purchases of naphtha and distillate unfinished oils.

4 Excludes: (1) ethanol in finished gasoline or E85 and (2) net purchases of other gasoline blendstocks; includes CBOBs and RBOBs, petroleum component of E85, BTX, propylene, naphthas, and aviation gas.

5 Exludes net purchases of jet fuel blendstocks.

5 Exludes net purchases of diesel fuel blendstocks.

7 Includes crude oil and purchased vacuum gas oils and residuum.

8 For DOE 2006, includes energy from small volumes of distillate, resid, marketable coke, other products, and coal that may have been used for fuel.

Sources: Refinery Fuel Use -- DOE Website; power generation -- Table 24, "Supplemental Tables," *Annual Energy Outlook 2008* , DOE/EIA; and modeling results from ARMS.

Exhibit C-3a: Estimated Energy Use and CO2 Emissions by Crude Oil, Additional Detail
PADD 2, Fix Cases

			Crude Oil Displacement Cases -- 2015						
			Domestic	Imported	Canadian				
	Calibration Case 2006	Reference Case 2015	West Texas Inter	Saudi Medium	Bow River	SCO		Synbit	Dilbit
						Mining	In Situ		
Fuel Use									
Refinery Gases and Natural Gas (K foeb/d)[1]	194	190	190	192	190	186	187	190	191
Natural Gas	63	73	74	74	71	71	72	71	72
Still Gas	130	117	116	117	119	115	115	119	119
Catalyst Coke (K b/d)	45	40	40	39	41	42	40	41	40
Power (MM Kwh/d)	31	31	31	31	31	31	31	31	31
Refinery Energy Use (Billion btu/d)	**1,797**	**1,747**	**1,740**	**1,752**	**1,756**	**1,730**	**1,728**	**1,754**	**1,755**
Hydrogen Production (Million scf/d)	414	574	559	615	584	548	537	595	621
CO2 Emissions (K MT/d)	**129**	**127**	**126**	**127**	**128**	**126**	**125**	**128**	**128**
Fuel	74	72	72	72	72	70	71	72	72
Natural Gas	21	24	25	25	24	24	24	24	24
Still Gas	53	47	47	47	48	47	46	48	48
Catalyst coke burned in FCC regen	28	25	25	25	26	26	25	26	25
Power	19	19	19	20	20	19	19	20	20
Hydrogen production	7	10	10	11	11	10	10	11	11
Crude Oil Energy Use (million btu/b)									
Composite Crude	0.543	0.561							
Displacement Crude			0.489	0.608	0.647	0.386	0.370	0.630	0.633
Adjusted for Delta Product Slate									
Crude Oil CO2 Emissions (MT/b)									
Composite Crude	0.039	0.041							
Displacement Crude			0.032	0.048	0.051	0.030	0.023	0.053	0.053
Adjusted for Delta Product Slate									
Change in Product Volume (K b/d)									
Gasoline									
Jet Fuel									
Diesel Fuel									
Residual Fuel									

Exhibit C-3b: Estimated Energy Use and CO2 Emissions by Crude Oil, Additional Detail
PADD 2, Float Cases

		Crude Oil Displacement Cases -- 2015						
		Domestic	Imported					
				Canadian				
	Reference Case 2015	West Texas Inter	Saudi Medium	Bow River	SCO		Synbit	Dilbit
					Mining	In Situ		
Fuel Use								
Refinery Gases and Natural Gas (K foeb/d)[1]	190	190	192	189	187	189	191	191
Natural Gas	73	74	74	70	72	74	71	71
Still Gas	117	116	118	120	116	115	119	119
Catalyst Coke (K b/d)	40	40	40	42	41	40	41	40
Power (MM Kwh/d)	31	31	31	31	31	31	31	31
Refinery Energy Use (Billion btu/d)	**1,747**	**1,744**	**1,755**	**1,755**	**1,736**	**1,737**	**1,758**	**1,754**
Hydrogen Production (Million scf/d)	574	556	616	585	563	557	609	611
CO2 Emissions (K MT/d)	**127**	**126**	**128**	**128**	**126**	**126**	**128**	**128**
Fuel	72	72	72	72	71	71	72	72
Natural Gas	24	25	25	23	24	25	24	24
Still Gas	47	47	48	48	47	46	48	48
Catalyst coke burned in FCC regen	25	25	25	26	26	25	26	25
Power	19	19	20	20	19	19	20	20
Hydrogen production	10	10	11	11	10	10	11	11
Crude Oil Energy Use (million btu/b)								
Composite Crude	0.561							
Displacement Crude		0.531	0.643	0.639	0.452	0.458	0.666	0.623
Adjusted for Delta Product Slate		0.507	0.590	0.643	0.357	0.396	0.616	0.642
Crude Oil CO2 Emissions (MT/b)								
Composite Crude	0.041							
Displacement Crude		0.034	0.051	0.053	0.035	0.029	0.057	0.053
Adjusted for Delta Product Slate		0.032	0.047	0.053	0.027	0.024	0.052	0.054
Delta Vol. from Reference (K b/d)[1]		**1**	**-1**	**-7**	**6**	**6**	**-1**	**-6**
Gasoline	1,618	3	10	4	14	7	10	1
Jet Fuel	171	2	-2	-2	-2	2	-2	-2
Diesel Fuel	920	-4	-9	-9	-6	-3	-9	-5
Residual Fuel	69	0	0	0	0	0	0	0

1 Maximum change of +/- 1% for gasoline, jet fuel, & diesel fuel; no change for residual fuel.

Exhibit C-4a: Estimated Energy Use and CO2 Emissions by Crude Oil, Additional Detail
PADD 3, Fix Cases

	Calibration Case 2006	Reference Case 2015	Crude Oil Displacement Cases -- 2015									
			Domestic	Imported					Canadian			
									SCO			
			West Texas Inter	Saudi Medium	Iraq Basrah Medium	Nigerian Escravos	Venezuelan Bachequero 17	Mexican Maya	Mining	In Situ	Synbit	Dilbit
Fuel Use												
Refinery Gases and Natural Gas (K foeb/d)[1]	504	497	496	497	497	495	496	498	493	494	496	497
Natural Gas	177	202	204	203	203	203	201	202	201	202	201	201
Still Gas	326	295	292	294	294	292	295	296	292	291	295	295
Catalyst Coke (K b/d)	124	119	118	119	119	119	120	119	121	119	120	119
Power (MM Kwh/d)	77	82	82	82	82	82	83	83	82	82	83	82
Refinery Energy Use (Billion btu/d)	**4,655**	**4,626**	**4,616**	**4,629**	**4,629**	**4,612**	**4,634**	**4,634**	**4,608**	**4,603**	**4,634**	**4,630**
Hydrogen Production (Million scf/d)	998	1,315	1,285	1,315	1,315	1,271	1,315	1,315	1,269	1,255	1,315	1,315
CO2 Emissions (K MT/d)	**332**	**332**	**331**	**332**	**332**	**331**	**333**	**333**	**331**	**330**	**333**	**333**
Fuel	191	187	186	187	187	186	187	187	185	185	187	187
Natural Gas	59	68	68	68	68	68	67	68	67	68	67	67
Still Gas	132	119	118	119	119	118	119	120	118	118	119	120
Catalyst coke burned in FCC regen	78	74	74	74	74	75	75	74	75	75	75	75
Power	44	47	47	47	47	47	47	48	47	47	47	47
Hydrogen production	18	24	23	24	24	23	24	24	23	23	24	24
Crude Oil Energy Use (million btu/b)												
Composite Crude	0.609	0.641										
Displacement Crude			0.543	0.673	0.673	0.501	0.723	0.722	0.465	0.417	0.724	0.687
Adjusted for Delta Product Slate												
Crude Oil CO2 Emissions (MT/b)												
Composite Crude	0.043	0.046										
Displacement Crude			0.033	0.048	0.048	0.031	0.056	0.052	0.033	0.023	0.056	0.051
Adjusted for Delta Product Slate												
Change in Product Volume (K b/d)												
Gasoline												
Jet Fuel												
Diesel Fuel												
Residual Fuel												

Exhibit C-4b: Estimated Energy Use and CO2 Emissions by Crude Oil, Additional Detail
PADD 3, Float Cases

		Crude Oil Displacement Cases -- 2015									
		Domestic	Imported								
	Reference Case 2015	West Texas Inter	Saudi Medium	Iraq Basrah Medium	Nigerian Escravos	Venezuelan Bachequero 17	Mexican Maya	Canadian			
								SCO			
								Mining	In Situ	Synbit	Dilbit
Fuel Use											
Refinery Gases and Natural Gas (K foeb/d)[1]	497	497	497	497	496	496	497	494	495	496	496
Natural Gas	202	205	203	203	205	200	201	203	204	201	201
Still Gas	295	292	294	294	291	296	295	291	290	295	296
Catalyst Coke (K b/d)	119	118	119	119	118	120	119	119	118	120	119
Power (MM Kwh/d)	82	82	82	82	82	83	82	82	82	83	82
Refinery Energy Use (Billion btu/d)	**4,626**	**4,616**	**4,629**	**4,629**	**4,611**	**4,633**	**4,625**	**4,608**	**4,603**	**4,635**	**4,626**
Hydrogen Production (Million scf/d)	1,315	1,288	1,315	1,315	1,287	1,315	1,315	1,302	1,276	1,315	1,315
CO2 Emissions (K MT/d)	**332**	**331**	**332**	**332**	**330**	**333**	**332**	**331**	**330**	**333**	**332**
Fuel	187	187	187	187	186	187	187	186	186	187	187
Natural Gas	68	69	68	68	68	67	67	68	68	67	67
Still Gas	119	118	119	119	118	120	119	118	117	119	120
Catalyst coke burned in FCC regen	74	74	74	74	74	75	74	75	74	75	75
Power	47	47	47	47	47	47	47	47	47	47	47
Hydrogen production	24	23	24	24	23	24	24	23	23	24	24
Crude Oil Energy Use (million btu/b)											
Composite Crude	0.641										
Displacement Crude		0.550	0.673	0.676	0.495	0.714	0.637	0.464	0.414	0.732	0.644
Adjusted for Delta Product Slate		0.552	0.681	0.681	0.523	0.732	0.716	0.480	0.436	0.735	0.697
Crude Oil CO2 Emissions (MT/b)											
Composite Crude	0.046										
Displacement Crude		0.032	0.048	0.048	0.028	0.056	0.047	0.034	0.021	0.057	0.049
Adjusted for Delta Product Slate		0.032	0.049	0.049	0.031	0.057	0.053	0.035	0.023	0.057	0.053
Delta Vol. from Reference (K b/d)[1]		**3**	**-3**	**-2**	**5**	**-4**	**-7**	**6**	**6**	**-2**	**-8**
Gasoline	3,232	-3	1	2	-9	0	-11	-8	-8	1	-4
Jet Fuel	715	4	-4	-4	4	-4	4	4	4	-3	-4
Diesel Fuel	1,958	2	0	0	10	0	0	10	10	0	0
Residual Fuel	290	0	0	0	0	0	0	0	0	0	0

[1] Maximum change of +/- 0.5% for gasoline, jet fuel, & diesel fuel; no change for residual fuel.

Exhibit C-5a: Estimated Energy Use and CO2 Emissions by Crude Oil, Additional Detail California, Fix Cases

			Crude Oil Displacement Cases -- 2015								
			Domestic		Imported						
								Canadian			
								SCO			
	Calibration Case 2006	Reference Case 2015	SJV Heavy	Alaskan North Slope	Saudi Medium	Iraq Basrah Medium	Mexican Maya	Mining	In Situ	Synbit	Dilbit
Fuel Use											
Refinery Gases and Natural Gas (K foeb/d)	127	126	127	125	126	127	129	124	123	127	128
Natural Gas	27	33	32	33	32	32	31	32	33	32	31
Still Gas	100	94	95	92	94	94	97	92	91	95	97
Catalyst Coke (K b/d)	30	28	29	28	28	28	27	29	27	29	28
Power (MM Kwh/d)	20	20	20	20	20	20	20	19	19	20	20
Refinery Energy Use (Billion btu/d)	**1,170**	**1,142**	**1,154**	**1,136**	**1,145**	**1,146**	**1,160**	**1,131**	**1,120**	**1,154**	**1,161**
Hydrogen Production (Million scf/d)	1,194	1,207	1,245	1,167	1,204	1,202	1,249	1,186	1,149	1,250	1,254
CO2 Emissions (K MT/d)	**101**	**98**	**100**	**97**	**99**	**99**	**100**	**98**	**96**	**100**	**101**
Fuel	50	49	49	48	49	49	50	48	48	49	50
Natural Gas	9	11	11	11	11	11	11	11	11	11	10
Still Gas	40	38	38	37	38	38	39	37	37	39	39
Catalyst coke burned in FCC regen	19	17	18	17	17	17	17	18	17	18	18
Power	11	10	10	10	11	11	11	10	10	10	11
Hydrogen production	22	22	22	21	22	22	23	21	21	23	23
Crude Oil Energy Use (million btu/b)											
Composite Crude	0.652	0.641									
Displacement Crude			0.754	0.576	0.669	0.677	0.814	0.526	0.415	0.761	0.829
Crude Oil CO2 Emissions (MT/b)											
Composite Crude	0.056	0.055									
Displacement Crude			0.073	0.043	0.057	0.057	0.073	0.048	0.030	0.073	0.078
Adjusted for Delta Product Slate											
Change in Product Volume (K b/d)											
Gasoline											
Jet Fuel											
Diesel Fuel											
Residual Fuel											

Exhibit C-5b: Estimated Energy Use and CO2 Emissions by Crude Oil, Additional Detail
California, Float Cases

		Crude Oil Displacement Cases -- 2015								
		Domestic		Imported			Canadian			
							SCO			
	Reference Case 2015	SJV Heavy	Alaskan North Slope	Saudi Medium	Iraq Basrah Medium	Mexican Maya	Mining	In Situ	Synbit	Dilbit
Fuel Use										
Refinery Gases and Natural Gas (K foeb/d)[1]	126	127	126	126	126	127	124	124	127	127
Natural Gas	33	32	34	32	32	30	33	33	32	31
Still Gas	94	95	92	94	94	97	90	90	95	96
Catalyst Coke (K b/d)	28	29	28	28	28	28	29	27	29	28
Power (MM Kwh/d)	20	20	20	20	20	20	19	19	20	20
Refinery Energy Use (Billion btu/d)	**1,142**	**1,154**	**1,138**	**1,142**	**1,144**	**1,148**	**1,131**	**1,120**	**1,156**	**1,149**
Hydrogen Production (Million scf/d)	1,207	1,250	1,167	1,199	1,205	1,223	1,168	1,142	1,254	1,226
CO2 Emissions (K MT/d)	**98**	**100**	**97**	**98**	**98**	**99**	**97**	**96**	**100**	**99**
Fuel	49	49	48	49	49	49	48	48	49	49
Natural Gas	11	11	11	11	11	10	11	11	11	10
Still Gas	38	38	37	38	38	39	37	37	39	39
Catalyst coke burned in FCC regen	17	18	17	17	17	17	18	17	18	18
Power	10	10	10	10	10	11	10	10	11	10
Hydrogen production	22	23	21	22	22	22	21	21	23	22
Crude Oil Energy Use (million btu/b)										
Composite Crude	0.641									
Displacement Crude		0.760	0.596	0.635	0.660	0.697	0.532	0.418	0.781	0.708
Adjusted for Delta Product Slate		0.765	0.577	0.650	0.655	0.716	0.527	0.386	0.770	0.748
Crude Oil CO2 Emissions (MT/b)										
Composite Crude	0.055									
Displacement Crude		0.074	0.044	0.054	0.056	0.063	0.044	0.028	0.075	0.065
Adjusted for Delta Product Slate		0.075	0.043	0.055	0.056	0.064	0.044	0.025	0.074	0.068
Change in Product Volume (K b/d)		**-1**	**2**	**-2**	**-2**	**-6**	**6**	**4**	**1**	**-6**
Gasoline	994	1	3	-3	1	-1	-3	2	2	-3
Jet Fuel	247	-4	-2	5	5	3	1	5	-4	-4
Diesel Fuel	399	3	1	-4	-7	-8	8	-2	3	1
Residual Fuel	56	0	0	0	0	0	0	0	0	0

1 Maximum change of +/- 2% for gasoline, jet fuel, & diesel fuel; no change for residual fuel.

Exhibit C-6a: Estimted Changes in Energy Use in ARMS Converted to BTUs, by Process Unit
PADD 2, Fix Cases
(Billion Btu/d)

			Crude Oil Displacement Cases -- 2015						
			Domestic	Imported					
		Reference	West		Canadian				
Type of		Case	Texas	Saudi	Bow	SCO			
Process	Process	2015	Inter	Medium	River	Mining	In Situ	Synbit	Dilbit
Crude Distillation	Atmos. & Vacuum	444	1.0	-0.5	-1.9	-4.9	-3.0	-0.4	-2.0
Conversion	Fluid Cat Cracking[1]	225	-1.9	-1.0	2.0	4.1	0.7	3.4	-2.0
	Hydrocracking	50		0.1	-1.5	0.1	0.1	0.1	
	Resid Processing[2]	45	-0.9	0.8	2.3	-2.1	-2.3	1.1	2.7
Upgrading	Alkylation[3]	78	-1.6	-1.3	1.4	0.1	-0.7	0.5	0.8
	Pen/Hex Isomerization	24		-1.2	-1.4	-0.3		-1.3	-0.1
	Reforming	138	1.0	-0.5	-1.7	-1.1	0.2	-1.6	-1.8
Hydrotreating	Naphtha[4]	89	0.6	-0.1	0.7	-0.5		-1.0	-0.1
	Distillate	65	-0.6	-0.1		-0.6	-1.5	0.1	0.5
	Gas Oil	46	-1.3	5.7	1.5	-3.6	-3.2	1.0	1.2
	Resid	0							
Other	Aromatics	35	0.7	-0.9	-0.2	-0.1	0.3	-0.1	-0.4
	Butane Isomerization	0							
	Ethers	0							
	Hydrogen	60	-1.4	4.0	1.0	-2.5	-3.5	2.1	4.5
	Lube Plant	45							
	Splitting	15	-0.4	2.1	2.6	0.6	-0.1	1.2	
	Sulfur Plant	15	-0.3	0.6	0.6	-0.6	-0.6	0.4	0.9
Total		**1374**							
Delta Energy			**-5**	**8**	**5**	**-11**	**-13**	**6**	**4**

Note: Total reflects uncalibrated Btu use for process units only (no energy use for product blending).
Also, does not reflect energy-use adjustments for FDS unit

[1] Net of BTUs generated from burning catalyst coke.

[2] Includes coking, visbreaking, and solvent deasphalting.

[3] Includes alkylation, polymerization, and dimersol.

[4] Includes FCC naphtha desulfurization

Exhibit C-6b: Estimted Changes in Energy Use in ARMS Converted to BTUs, by Process Unit PADD 3, Fix Cases

(Billion Btu/d)

			Crude Oil Displacement Cases -- 2015									
			Domestic	Imported								
		Reference Case 2015	West Texas Inter		Iraq		Venezuelan		Canadian			
									SCO			
Type of Process	Process			Saudi Medium	Basrah Medium	Nigerian Escravos	Bachequero 17	Mexican Maya	Mining	In Situ	Synbit	Dilbit
Crude Distillation	Atmos. & Vacuum	968	1.2	-0.3	-0.2	1.3	-1.7	-1.8	-4.7	-2.7	-0.2	-1.8
Conversion	Fluid Cat Cracking[1]	511	-0.5	0.1	0.1	1.6	4.1	0.4	4.6	3.5	4.3	-1.4
	Hydrocracking	144	-0.1	-0.2	-0.2	-0.1	-0.3	-0.3	-0.1	-0.2	-0.2	-0.3
	Resid Processing[2]	187	-1.6	0.1	-0.1	-2.0	2.1	2.1	-2.7	-2.8	0.5	2.4
Upgrading	Alkylation[3]	166	-1.8	-0.1	-0.4	-2.0		0.1	-0.2	-1.3	1.0	-0.3
	Pen/Hex Isomerization	31										
	Reforming	287	0.1	-0.8	-0.7	-1.4	-5.4	-2.3	-2.1	-2.0	-3.9	-0.7
Hydrotreating	Naphtha[4]	205	0.7	0.3	0.4	0.1	-0.1	0.3		0.1	-0.3	1.1
	Distillate	138	0.1	0.2	0.5	0.6	0.8	1.8	0.7	0.6	0.4	0.9
	Gas Oil	103	-2.2	2.4	2.5	-3.1	2.1	2.4	-4.1	-3.5	0.5	0.4
	Resid	50	-0.2	0.9	0.9	-0.8	0.9	0.9	-0.2	-1.9	0.9	0.4
Other	Aromatics	137	0.1	-0.1	-0.1	0.5	0.5		-0.1	0.4	0.2	-0.9
	Butane Isomerization	3	-0.2			-0.3		0.1	-0.1	-0.2	0.1	
	Ethers	0										
	Hydrogen	152	-2.8			-4.1			-4.4	-5.7		
	Lube Plant	332										
	Splitting	63	0.7	0.2	0.2	0.4	1.8	0.8	0.3	0.3	1.0	0.3
	Sulfur Plant	46	-0.5	0.4	0.4	-0.7	0.5	0.8	-0.8	-0.8	0.3	0.9
Total		**3523**										
Delta Energy			**-7**	**3**	**3**	**-10**	**5**	**5**	**-14**	**-16**	**5**	**1**

Note: Total reflects uncalibrated Btu use for process units only (no energy use for product blending).
Also, does not reflect energy-use adjustments for FDS unit

[1] Net of BTUs generated from burning catalyst coke.

[2] Includes coking, visbreaking, and solvent deasphalting.

[3] Includes alkylation, polymerization, and dimersol.

[4] Includes FCC naphtha desulfurization

Exhibit C-6c: Estimted Changes in Energy Use in ARMS Converted to BTUs, by Process Unit
California, FIx Cases
(Billion Btu/d)

			Crude Oil Displacement Cases -- 2015								
			Domestic		Imported			Canadian			
								SCO			
Type of Process	**Process**	**Reference Case 2015**	**SJV Heavy**	**Alaskan North Slope**	**Saudi Medium**	**Iraq Basrah Medium**	**Mexican Maya**	**Mining**	**In Situ**	**Synbit**	**Dilbit**
Crude Distillation	Atmos. & Vacuum	236	-0.7	0.7			-1.5	-4.5	-2.5		-1.5
Conversion	Fluid Cat Cracking[1]	109	3.6	0.1	0.3	-0.2	-1.3	1.1	-0.2	1.8	0.3
	Hydrocracking	95	-0.5	-0.6	-0.2	-0.4	0.3	0.6	0.5	-0.3	-0.6
	Resid Processing[2]	69	1.5	-0.9	0.3	-0.1	2.9	-2.7	-3.0	0.3	2.9
Upgrading	Alkylation[3]	64	0.1	-0.8				-1.8	-2.7	-0.5	0.7
	Pen/Hex Isomerization	14					-0.2				
	Reforming	75	-3.5	0.6	-1.7	-0.5	-0.7	0.6	1.3	-1.6	-2.1
Hydrotreating	Naphtha[4]	51	0.1	0.7	0.5	0.5	0.3	-0.1	0.2	0.1	1.1
	Distillate	57	2.1	-1.5	1.2	2.1	8.9	0.8	-4.6	4.7	7.1
	Gas Oil	53	2.3	0.5	1.4	1.0	3.5	-3.0	-2.1	1.6	3.6
	Resid	0									
Other	Aromatics	9	-1.1	0.2		0.2	0.1	-0.8	-0.2	-0.6	-0.2
	Butane Isomerization	1	-0.1	0.1			-0.1	0.1			
	Ethers	0									
	Hydrogen	119	3.6	-3.8	-0.3	-0.5	4.0	-2.0	-5.6	4.1	4.4
	Lube Plant	45									
	Splitting	27	0.6	-0.5	0.2		-0.5	0.3	-0.2	-0.1	-0.3
	Sulfur Plant	12		-0.3	0.6	0.6	1.0	-0.7	-0.7	0.5	1.2
Total		**1037**									
Delta Energy			**8**	**-6**	**2**	**3**	**17**	**-12**	**-20**	**10**	**17**

Note: Total reflects uncalibrated Btu use for process units only (no energy use for product blending).
Also, does not reflect energy-use adjustments for FDS unit

[1] Net of BTUs generated from burning catalyst coke.

[2] Includes coking, visbreaking, and solvent deasphalting.

[3] Includes alkylation, polymerization, and dimersol.

[4] Includes FCC naphtha desulfurization