APPENDIX C

Market Analysis Supplemental Information

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SUPPLEMENTAL INFORMATION TO MARKET ANALYSIS

TABLE OF CONTENTS

1.0 Introduction 1
2.0 Relationship of PADD Regions to U.S. Crude Oil Market 1
2.1 PADD Supply Characteristics 1
2.2 Refinery Crude Selection Process 2
2.3 Refinery Upgrading and Expansion Projects Status 4
2.3.1 Midwest 4
2.3.2 Gulf Coast 4
3.0 Comparison of Annual Energy Outlook 2013, 2010, and the EnSys Low-Demand Outlooks 5
4.0 Discounts on Price of Inland Crude Due to Logistical Constraints 6
5.0 Pipeline and Rail Cost Information 13
6.0 Comparison of U.S. Product Demand, Annual Energy Outlook 2010 and 2012 14
7.0 Crude by Rail Loading, Off-Loading, and Transloading Facilities 15
8.0 Estimated WCSB Crude Oil Transport Capacity 20
9.0 Transport Costs from the Gulf Coast Area to Asian Ports 24
10.0 References 24

ATTACHMENT

Department of State Memo: The North American Oil Market Outlook, January 4, 2013

INDEX OF TABLES

Table 1 U.S. Product Demand Outlook 5
Table 2 Global Liquids Demand Outlook 6
Table 3 Impact of Pipeline Commitment Period on Tariffs: Example 1 13
Table 4 Impact of Pipeline Commitment Period on Tariffs: Example 2 13
Table 5 Estimated Delivered Cost via Rail on Selected Movements of Crude[a] 14
Table 6 PADD 1 Crude by Rail Offloading 15
Table 7 PADD 2 Bakken Rail Loading 16
Table 8 PADD 2 Non-Bakken Loading 17

Table 9 PADD 2 Rail to Marine Transloading Facilities 17
Table 10 PADD 2 Stroud to Cushing Loading/Transloading/Offloading Facilities 17
Table 11 PADD 3 Rail Terminals 18
Table 12 PADD 4 Rail Loading 19
Table 13 PADD 5 Rail Offloading/Transloading 19
Table 14 Canadian Rail Loading Facilities 20
Table 15 Estimated Existing Western Canada Pipeline Capacity[a] 21
Table 16 Estimated Western Canadian Sedimentary Basin Crude Oil Transport Capacity 22
Table 17 U.S. Gulf Crude Oil Exports, 2015 Outlook, VLCC and Suezmax[a] 24

INDEX OF FIGURES

Figure 1 Annual Average Price Spreads, LLS minus WTI, dollars/barrel 7
Figure 2 Average Crude Oil and Gasoline Price Spreads, dollar/bbl spread 9
Figure 3 Refinery Margins: Group 3 and Gulf Coast Area 10
Figure 4 Refinery Margins: Chicago and Gulf Coast Area 11
Figure 5 Annual Average Price Spreads, LLS minus Brent, dollars/barrel 12
Figure 6 Comparison of AEO 2010 and 2012 U.S. Product Demand – Total Liquids 15

ACRONYMS AND ABBREVIATIONS

AB	Alberta
AEO	Annual energy outlook
AL	Alabama
bbl	barrel
BNSF	Burlington Northern-San Francisco Railway
BP	British Petroleum
bpd	barrels per day
CA	California
CAPP	Canadian Association of Petroleum Producers
CN	Canadian National
CO	Colorado
CP	Canadian Pacific Railway
CPRS	Canadian Pacific Railway System
CSXT	CSX Transportation
DE	Delaware
dilbit	diluted bitumen
EIA	U.S. Energy Information Administration
EIS	Environmental Impact Statement
EOG	EOG Resources, Inc.
EOLA	Eola Yard, a BNSF Railway yard
FL	Florida
GT	GT Logistics LLC
IL	Illinois
KCS	Kansas City Southern Railway Company
KMEP	Kinder Morgan Energy Partners LP
L.P.	Limited Partnership
LA	Louisiana
LLS	Light Louisiana Sweet crude
LOOP	Louisiana Offshore Oil Port
LP	Limited Partnership
LPG	liquefied petroleum gases
MB	Manitoba
MMA	Montreal, Maine & Atlantic Railway, Ltd.
MO	Missouri
MS	Mississippi
MT	metric tons
MT	Montana
mmbpd	million barrels per day
NB	New Brunswick
ND	North Dakota
NJ	New Jersey
NM	New Mexico
NY	New York
NYMEX	New York Mercantile Exchange
OK	Oklahoma
OKDOT	Oklahoma Dept. of Transportation
OR	Oregon
PA	Pennsylvania
PADD	Petroleum Administration for Defense District
PQ	Province of Quebec, now abbreviated QC
SK	Saskatchewan
SLWC	Stillwater Central Railroad
TET	Texas Eastern Transmission Pipeline
TX	Texas
UP	Union Pacific Railroad Company
USGC	U.S. Gulf Coast
VA	Virginia
VLCC	very large crude carrier
WA	Washington
WCS	Western Canada Select crude
WCSB	Western Canadian Sedimentary Basin
WEO	World Energy Outlook
WI	Wisconsin
WRB	WRB Refining, LLC operates joint-venture WRB Refinery
WTI	West Texas Intermediate crude
WY	Wyoming

1.0 INTRODUCTION

This appendix supplements information related to the Market Analysis in the Supplemental Environmental Impact Statement (EIS) (Section 1.4, Market Analysis). The Supplemental EIS refers to specific section numbers in this appendix.

2.0 RELATIONSHIP OF PADD REGIONS TO U.S. CRUDE OIL MARKET

This section expands upon the discussion of U.S. Petroleum Administration for Defense District (PADD) regions by providing additional background information related to locations, characteristics, and refining and supply profiles of the PADDs and their interactions in the crude oil market. This section also includes refinery upgrading and expansion projects.

The 50 states and the District of Columbia are divided into five districts. The origin of PADDs dates from World War II when it was necessary to allocate the domestic petroleum supply. The "boundaries" between the different PADDs do not reflect either a regulatory or a business requirement; however, the boundaries allow the U.S. Energy Information Administration (EIA) a mechanism to consistently report the key attributes of the petroleum industry (inventory, crude processing levels, prices, consumption, etc.) over various time periods:

- PADD 1 (East Coast):
  - PADD 1A (New England): Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.
  - PADD 1B (Central Atlantic): Delaware, District of Columbia, Maryland, New Jersey, New York, and Pennsylvania.
  - PADD 1C (Lower Atlantic): Florida, Georgia, North Carolina, South Carolina, Virginia, and West Virginia.
- PADD 2 (Midwest): Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Tennessee, and Wisconsin.
- PADD 3 (Gulf Coast): Alabama, Arkansas, Louisiana, Mississippi, New Mexico, and Texas.
- PADD 4 (Rocky Mountain): Colorado, Idaho, Montana, Utah, and Wyoming.
- PADD 5 (West Coast): Alaska, Arizona, California, Hawaii, Nevada, Oregon, and Washington.

2.1 PADD SUPPLY CHARACTERISTICS

In general, each PADD reflects the typical supply patterns described in this section. PADD 1, the East Coast, is supplied by petroleum imports from foreign countries as well as refineries in PADD 3. Mid-Atlantic region refineries also supply PADD 1. PADD 3 refineries move product into PADD 1 via Colonial pipeline and Kinder Morgan's Plantation pipeline, while marine movements from the Gulf Coast supply Florida. PADD 1 refineries process crude oil solely from foreign sources and in general require light, sweet, and therefore expensive crude oil relative to refiners in other U.S. PADD regions.

PADD 2 is a large region stretching from the Plains states (Oklahoma through North Dakota) and east to Ohio, Tennessee, and Kentucky. In general, PADD 2 is the Midwest district and it contains several distinct markets, with the Group and Chicago markets being subsets of PADD 2. The Group is the region of refineries, pipelines, and states from Oklahoma north to Minnesota and North Dakota. These are supplied by refiners in the Group as well as imports from PADD 3 via Magellan and Explorer pipelines. The Chicago market (northern and eastern region) also imports product from PADD 3 through the Explorer and TET[1] (Enterprise) pipeline systems. Overall, PADD 2 is far less dependent upon waterborne imports than PADD 1, as PADD 2 has significant refining capacity. PADD 2 processes significant volumes of Canadian crude.

PADD 3 is the major petroleum-refining center of the United States. Most refineries are located along the Gulf Coast (except some in the Texas Panhandle, New Mexico, and Arkansas) and process a high percentage of foreign crude, which arrives by marine vessels. Product from PADD 3 is shipped into PADD 1 and PADD 2 markets. Product not required for demands in PADDs 1 through 3 is often exported from PADD 3 to Latin America and European countries. PADD 3 has, to date, processed very limited volumes of Canadian crude.

PADD 4 is the Rocky Mountain region. This area has smaller refineries sized for relatively stable and low demand levels in this region. Refiners process both local domestic and Canadian crudes.

PADD 5 is the West Coast region. Refineries are concentrated in California and the Puget Sound region. The market is difficult to supply since it is isolated from other PADDs with no connecting pipelines, and California has unique environmental gasoline specifications that are difficult to produce and transport from other sources. Canadian crude moves primarily by pipeline into several Puget Sound refineries. Arizona, Nevada, and Oregon are supplied from California and Washington area refiners.

2.2 REFINERY CRUDE SELECTION PROCESS

Refineries perform the role of taking raw crude oil, boiling it into different fractions (naphtha, kerosene, gas oil, and residuum), and converting those fractions through additional processes (thermally heating, catalytic reactions, and cracking larger molecules into smaller ones) into blendstocks used for products such as gasoline, diesel, jet fuel, and heating oil. While most U.S. refineries have these functions, each refinery is unique in that it has different levels of processing capacity for handling all the fractions, and also has different metallurgy and treating processes that may or may not allow the refinery to run certain types of crude oils. These different "hardware" characteristics may cause one refiner to value a specific crude oil differently than another crude oil.

Each refinery has a programming model of their facility that reflects their specific capacities, limitations, and processing options (e.g., ability to maximize gasoline yield and diesel yield). These refinery configurations allow the refiner to evaluate specific crude supply options by entering the estimated crude oil cost, crude oil characteristics (percentages of naphtha, kerosene,

[1] Texas Eastern Transmission Pipeline

other distillates, or molecules in the crude oil), and the estimated and wholesale (spot) market prices for the refinery products.

Generally, refineries evaluate crude oils available to them based on their location and available crude oil supply. Refiners in PADD 1 focus on purchasing the cheapest foreign low-sulfur or sweet crudes they can, and select the crude oil that provides them the best product yield for the crude price. For example, PADD 1 refiners have been acquiring railcar supply of Bakken crude from North Dakota because, even with relatively high railcar shipping costs, Bakken crude arrives on the East Coast at a much lower price than other crude oil with similar characteristics imported from Africa.

Refiners in PADD 3 also rely heavily on foreign imports. However, many PADD 3 refiners are designed to process very heavy, cheaper crude oil than refiners in PADD 1. PADD 3 has a particularly high heavy crude oil processing capacity in part because of the proximity of large supplies of heavy crude oil in Mexico and Venezuela. In addition, Mexico and Venezuela, through their state-controlled oil companies, supported expansion of the heavy oil refining capacity through several joint-venture investments in Gulf Coast refineries to create a more profitable market for their heavy crude oil resources. Consequently, heavy, high-sulfur crude oil from Venezuela and Mexico, as well as newer heavy sources from Brazil and Colombia, are generally more optimal for these refiners to process than domestic or imported light, sweet crude.

A refiner that processes heavy crudes has invested significant amounts of money to install the equipment necessary to process them. A refiner that has made these investments has economic incentive to continue to process heavy crudes and may not be able to process significantly lighter crude slates as profitably. For example, if a refinery configured to process a heavy slate of crude oil was constrained to processing only a light crude oil slate, the volume of gasoline and diesel fuels produced could decrease by 15 to 20 percent. This, in most cases would be because the refiner's crude oil distillation process is designed for crudes with much less *light* components, such as naphtha, as heavier crudes. Attempting to process high percentages of light crude oil in these units would overload the distillation towers with light products and require a reduction in crude processing. Not only would the refiner usually be paying relatively more for that light slate of crude oil, it would be producing less gasoline and diesel from it. This is the primary reason refiners would not typically replace a heavy crude oil slate with 100 percent light crudes (IHS CERA 2011).

To go back to efficiently process more light crudes more economically, those refiners would have to make additional expenditures in refinery equipment to reconfigure the distillation towers to handle the lighter crude, and add capacity to process the higher naphtha content into finished gasoline. Thus, even if an influx of light domestic crudes makes them comparatively price advantaged to heavy crude oils, the size of capital expenditure and downed production time for refiners may offset potential benefits of trying to process more light crudes (Platts 2012).

That said, ultimately refiners will shift their crude slate if they determine that they could achieve a higher profit level by making changes to their crude runs or crude slate, including making investments to shift to a lighter crude slate. Refiners determine the optimal crudes to process like any other manufacturing company selecting the right raw materials to manufacture products. Refining companies (including refining divisions in large, integrated major oil companies) pay market prices for the crude oil they run and measure their profitability based on selling their product into the wholesale spot market with an added margin. They then use that margin to cover their fixed and variable expenses. Refiners may select a more expensive crude oil if that crude oil's yield provides a greater margin than a cheaper crude.

Finally, some refiners have more flexibility to receive different crude oils than others based on location and storage capability. Refiners in the Gulf Coast area[2] generally have the greatest access since there are marine and pipeline options to receive both foreign and domestic crude and this will increase as more pipeline expansions are completed in the next several years. Some Gulf Coast area refiners may process as many as 50 different crude oils in a given year, constantly optimizing their crude selection based on available cargoes of crude oil. Meanwhile, others tend to rely on several major suppliers such as Saudi Arabia or Mexico for the bulk of their supply.

2.3 Refinery Upgrading and Expansion Projects Status

The prior 2011 Final EIS analysis and a study by EnSys Energy & Systems, Inc. incorporated a number of refinery expansion and/or upgrading projects in the proposed Project's impact assessment (EnSys 2010). For the most part, these projects are being constructed as noted in the Final EIS and detailed below. However, subsequent changes and updates have been made to some of these projects.

2.3.1 Midwest

Planned refinery upgrading projects at BP Whiting, Marathon Detroit, and BP-Husky Toledo are under construction and should be completed in 2013–2014. The projects will increase runs, or the oil volumes processed, of Western Canadian Sedimentary Basin (WCSB) heavy crude oil by about 0.400 million barrels per day (mmbpd), and reduce runs of light crude by 0.370 mmbpd. The upgrading at the WRB Refinery in Wood River, Illinois, (joint venture between Phillips 66 and Cenovus) was completed in 2011. Processing of heavy Canadian crude oil at Wood River has increased from about 0.030 mmbpd in 2009 to 0.185 mmbpd in the first half of 2012, with reductions in domestic light crude oil processing.

2.3.2 Gulf Coast

Valero has elected to cancel a major project at its Texas City refinery to construct a coker[3] (referred to in the 2011 Final EIS market analysis). Valero commented that due to the increased supply of domestic light crude oil and delivery uncertainty of heavy crude oil supplies from the WCSB (because of potential ongoing constraints on additional pipeline capacity, particularly uncertainty about the proposed Project), light/heavy crude price differentials would narrow and would make additional new investments to process heavy crude uneconomic (Reuters 2012).

Other identified major expansion and upgrading projects in the Gulf Coast have been completed. The Total Port Arthur project has been completed, increasing heavy crude oil runs by 0.070 mmbpd (using imports from Brazil and Venezuela) from 2009 and decreasing light imports.

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[2] The Gulf Coast area refers to the region from Houston, Texas, to Lake Charles, Louisiana.

[3] A coker is a refinery process that converts heavy residue oil from the rest of the crude oil (oil that boils at over 1000 degrees Fahrenheit) into lighter oils for further processing. The coker also produces petroleum coke, a fuel similar to coal. Cokers enable refineries to manufacture a higher yield (quantity) of gasoline and distillate fuel from heavy crude oil.

The Marathon major refinery expansion and upgrading project in Garyville, Louisiana, was completed in 2010. Marathon has increased imported crude runs significantly in 2011 and 2012, with imports increasing from about 0.138 mmbpd in 2009 to 0.380 mmbpd in 2012. Heavy crude imports have increased from 0.060 to 0.100 mmbpd, with the increase primarily heavy Canadian.

The Shell Motiva Port Arthur expansion was completed in early 2012. This project would increase Shell Motiva crude oil refining runs by 0.325 mmbpd, making the refinery the largest in the United States. While completed, the refinery suffered a fire in the new crude unit, which has led to a possible delay in full operation until 2013.

Both the Marathon Garyville and the Shell Motiva projects appear to have resulted in significant increases of crude imports from Saudi Arabia. Since Motiva is a joint venture between Shell and Saudi Aramco, there may be some equity obligations that may limit the option or the volume of WCSB crude oil that could be processed, and Marathon would be looking for pipeline alternatives to get WCSB crude oil into the Louisiana market. While it appears both refiners could run additional heavy crude, limited access to heavy Canadian and/or additional Mexican and other foreign heavy crudes have resulted in increased runs of more expensive and lighter Middle East crude. The need to turn to more Middle East crude was anticipated in the EnSys report as a likely outcome if there were long-term constraints on North American pipeline capacity.

3.0 COMPARISON OF ANNUAL ENERGY OUTLOOK 2013, 2010, AND THE ENSYS LOW-DEMAND OUTLOOKS

This section provides the data used for generating the figures in the Supplemental EIS that compare the demand outlooks in the U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2013, AEO 2010, and the EnSys Low Demand outlook (Table 1 and Table 2).

Table 1 U.S. Product Demand Outlook

Type	Outlook	2015	2020	2025	2030	2035	2040
LPG	AEO 2010	2.2	2.4	2.3	2.3	2.2	
	Low Demand	2.2	2.3	2.3	2.3		
	AEO 2013	2.6	2.9	3.0	2.9	2.8	2.8
Gas/E85	AEO 2010	9.3	9.4	9.6	9.9	10.3	
	Low Demand	9.2	8.6	7.8	7.1		
	AEO 2013	8.6	8.4	7.9	7.5	7.2	7.2
Jet/Distillate	AEO 2010	5.8	6.0	6.2	6.6	6.7	
	Low Demand	5.7	5.7	5.7	5.4		
	AEO 2013	5.8	6.0	6.1	6.2	6.2	6.3
Residual Fuel	AEO 2010	0.7	0.6	0.6	0.6	0.7	
	Low Demand	0.7	0.6	0.6	0.5		
	AEO 2013	0.5	0.5	0.5	0.5	0.5	0.5

Type	Outlook	2015	2020	2025	2030	2035	2040
Other	AEO 2010	3.3	2.8	2.8	2.8	2.2	
	Low Demand	3.3	2.7	2.7	2.6		
	AEO 2013	2.0	2.0	2.0	2.0	2.1	2.1
Total Liquids Demand	AEO 2010	21.3	21.2	21.5	22.2	22.0	
	Low Demand	21.1	19.9	19.1	17.9		
	AEO 2013	19.5	19.8	19.5	19.0	18.9	18.9

Sources: EIA 2010; EIA 2013; EnSys 2010.
AEO = Annual Energy Outlook, LPG = liquefied petroleum gases.

Table 2 Global Liquids Demand Outlook

	2015	2020	2025	2030	2035	2040
AEO 2010	90.9	95.6	100.7	105.9	111.7	
Low Demand	93.0	94.5	100.9	102.2		
AEO 2013	93.2	99.7	105.3	108.5	110.3	112.9

Sources: EIA 2010; EIA 2013; EnSys 2010.
AEO = Annual Energy Outlook.

4.0 DISCOUNTS ON PRICE OF INLAND CRUDE DUE TO LOGISTICAL CONSTRAINTS

This section provides additional information and background related to the discounts of inland crude prices due to logistical constraints in the crude oil market. Supplemental data and narrative are also provided to explain the effects of these discounts on both U.S. and global refinery and import/export trends.

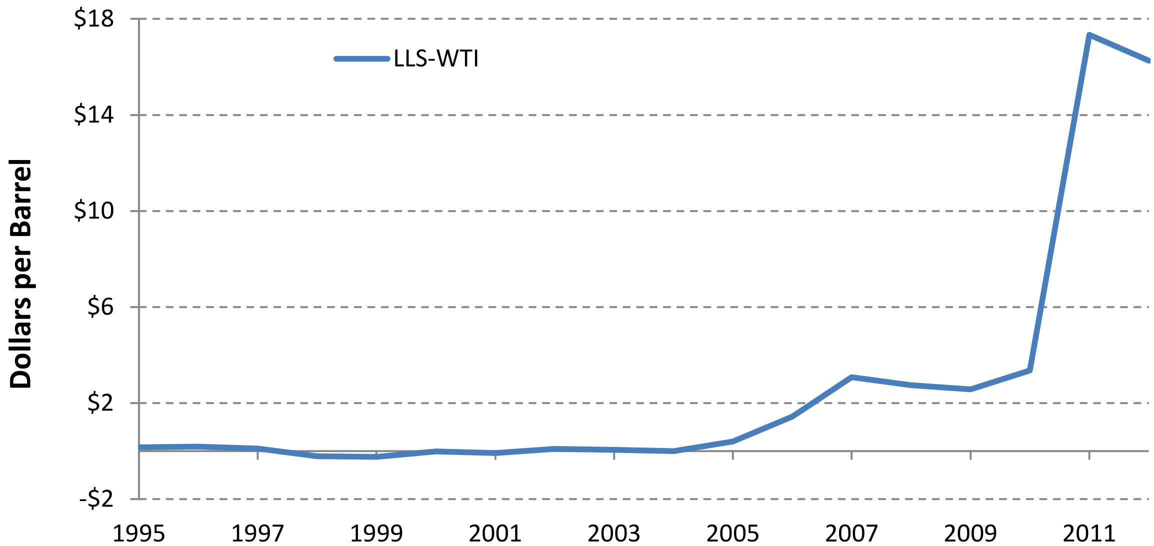
Crude oil absolute prices can vary for a number of reasons, including global demands for petroleum, geo-political concerns in the Middle East, currency values, and the activities of market speculators. Typically, prices for petroleum products tend to follow prices for crude oil, but in some cases product surpluses or shortages can cause product price differentials to crude oil to vary. Similarly, prices for different crude oils can vary due to quality considerations. For example, high-sulfur crude oils and crudes that are denser (heavier) than others require more intense refining to crack and rearrange the hydrocarbon molecules into transportation fuels like gasoline and diesel. Consequently, these crude oils tend to be priced lower than crudes that are less dense and have less sulfur and other contaminants that must be refined.

In addition, crudes of similar type (light or heavy) may have different prices based on where they are located and how those crudes are delivered into a refinery. For example, three major light crude types have traditionally influenced U.S. light crude pricing: light crudes based on Brent crude pricing (North Sea crudes, West African crudes) for delivery to the U.S. Gulf Coast; Light Louisiana Sweet (LLS) for delivery to the U.S. Gulf Coast; and West Texas Intermediate (WTI) for delivery to Cushing, Oklahoma.[4] Historically, crude oil prices in Europe and Africa based on Brent pricing typically have had a $2 to $3 per barrel discount to LLS. The producers of those

[4] WTI is the crude oil underlying the New York Mercantile Exchange (NYMEX) crude oil futures contracts. The basis of these contracts is delivery of WTI into Cushing, Oklahoma.

crudes need to provide that discount to account for the additional $2 to $3 transportation cost per barrel to ship their crude oil across the Atlantic Ocean to be competitive with LLS and other foreign crudes available in the U.S. Gulf Coast.

More recently since early 2011, the growth in domestic light crude production (Bakken, Niobrara, and Eagle Ford crudes) and displacement of light crude by several refiners streaming[5] heavy crude upgrading projects created a crude oil bottleneck at the Cushing, Oklahoma, hub. With no viable options to move light crude to Gulf Coast area refineries, the crude at Cushing and further north to the Bakken region became heavily discounted by producers to remain competitive against traditional markers such as LLS or Brent[6] (Figure 1). This led to the prevailing highly unusual market situation where a Gulf Coast area refiner processing LLS would have had to pay as much as $20 to $25 per barrel more (at various times) for a light crude than a refiner in Oklahoma would pay for a crude with similar yields (WTI)[7]. This situation gives refiners in the Midcontinent region[8] that purchase crude oil based on the WTI price a significant crude oil cost advantage over Gulf Coast area refiners.



Source: Bloomberg 2012.
Notes: Bloomberg WTI pricing (ticker symbol: USCRWTIC Index); Bloomberg LLS pricing (ticker symbol: USCRLLSS Index). LLS = Light Louisiana Sweet crude, WTI = West Texas Intermediate crude.

Figure 1 Annual Average Price Spreads, LLS minus WTI, dollars/barrel

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5 Streaming is the process of bringing new processing units into operation.

6 A crude oil marker or benchmark is a type of oil with similar characteristics, such as weight (heavy, intermediate, or light), sulfur content, and other chemical features that allow buyers and sellers to understand what is being traded. Oil purchased by U.S. refineries from overseas would be discounted to allow for cost differentials in transport.

7 This analysis is supported by an independent academic paper (Borenstein and Kellogg 2012).

8 The Midcontinent region includes refiners in the Plains states (Oklahoma, Kansas, Nebraska South Dakota, and North Dakota). In sum, this is the PADD 2 region with some additional refiners in north Texas.

The lack of pipeline capacity to move crude from Cushing to the Gulf Coast area created a bottleneck for both light and (increasingly) heavy crudes as Canadian production increased. At the time of the Final EIS in 2011, there was clear evidence of Midcontinent crude pricing discounts versus the Gulf Coast area (which increased substantially in early 2011). However, this pricing inversion is likely to continue for some time as new light crude production growth continues to outpace the development of pipeline capacity to move the Cushing surplus south to the Gulf Coast area. The larger pipeline projects (Seaway Reversal Phase 2, Seaway "Twin" line, and TransCanada Gulf line) will be available beginning in late 2013 and 2014, and rail takeaway from the Bakken to the East, West, and Gulf Coasts is clearly developing, which may help reduce the Cushing surplus somewhat in the interim. The initial phase of the Seaway reversal (Phase 1) has already been completed and became operational in May 2012. Impact on the LLS versus WTI differential has been indiscernible.

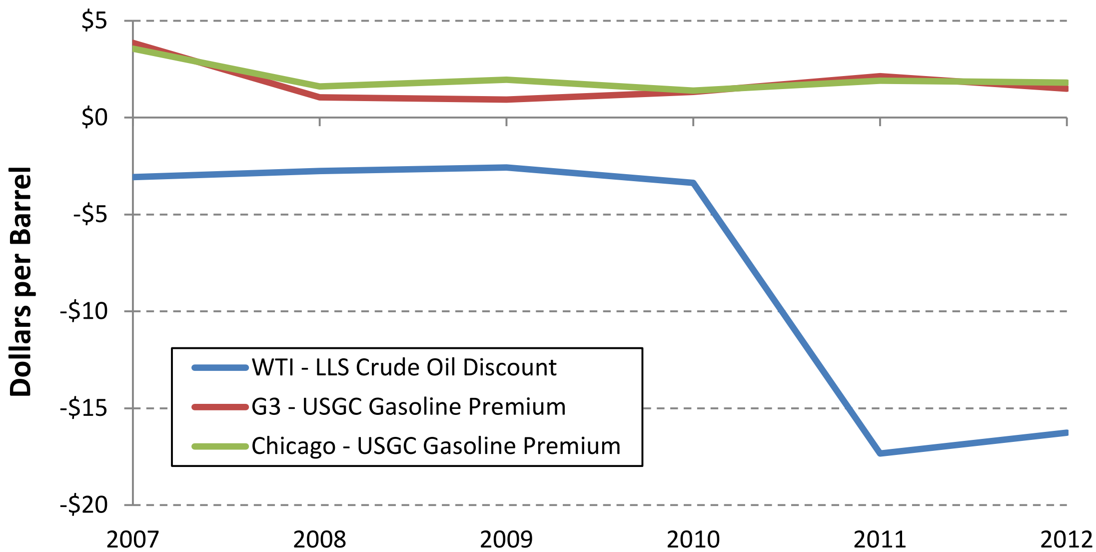
The steep discounts in the Midcontinent and upper Midwest/Chicago crude prices have resulted in that region's refiners attempting to maximize crude runs (that is, have the best mix of light versus heavy oil to produce the highest refinery margin). According to market data over the period (Figure 2), despite the discount in crude price, wholesale[9] product prices in the Chicago and Group 3 markets[10]—for the most part—did not follow crude price discounts. Figure 2 shows that during the period that WTI crude has been steeply discounted to similar crude oils on the Gulf Coast (shown by the blue line in Figure 2), the wholesale price of gasoline in the Midwest (Chicago and Group 3 region) remained generally higher than that on the Gulf Coast (shown by the green and red lines in Figure 2).

Gasoline in the Midwest was not cheaper than gasoline on the Gulf Coast because the entire Midwest and Group 3 region lacks sufficient refinery capacity to meet gasoline and diesel demands, and the region requires additional gasoline and diesel supply from the Gulf Coast (via Explorer and Magellan pipeline systems.) Therefore, product prices typically reflect Gulf Coast market plus pipeline costs. The actual wholesale product market behavior (that is, prices) demonstrated that consumers in the Midwest did not benefit from crude surplus price discounts. Instead, the beneficiary was Midwest refiners as the stable product prices resulted in extraordinarily high refinery gross margin levels and, therefore, higher refinery profit levels in the Chicago and Group 3 markets (Figure 3 and Figure 4). [11]

[9] Wholesale prices are used since retail prices include federal, state, and local taxes and other charges that can vary from state-to-state or within a state.

[10] Group 3 market is the term for spot market product prices in the Plains states west of the Mississippi River. It specifically entails delivery of finished petroleum products along key pipelines serving Oklahoma, Missouri, Kansas, Iowa, Nebraska, Minnesota, South Dakota, and North Dakota. *Group 3* is the industry nomenclature for the oil refining and distribution system serving these markets.

[11] Midwest product supply has been supplemented by shipments into Explorer or Magellan pipelines from the Texas and Louisiana markets. Higher refinery production and lower demands in the Midwest could result in surplus product supply. However, traders and refiners have an option to ship less on Explorer and Magellan to the Midwest and divert more supply to the East Coast or export market.

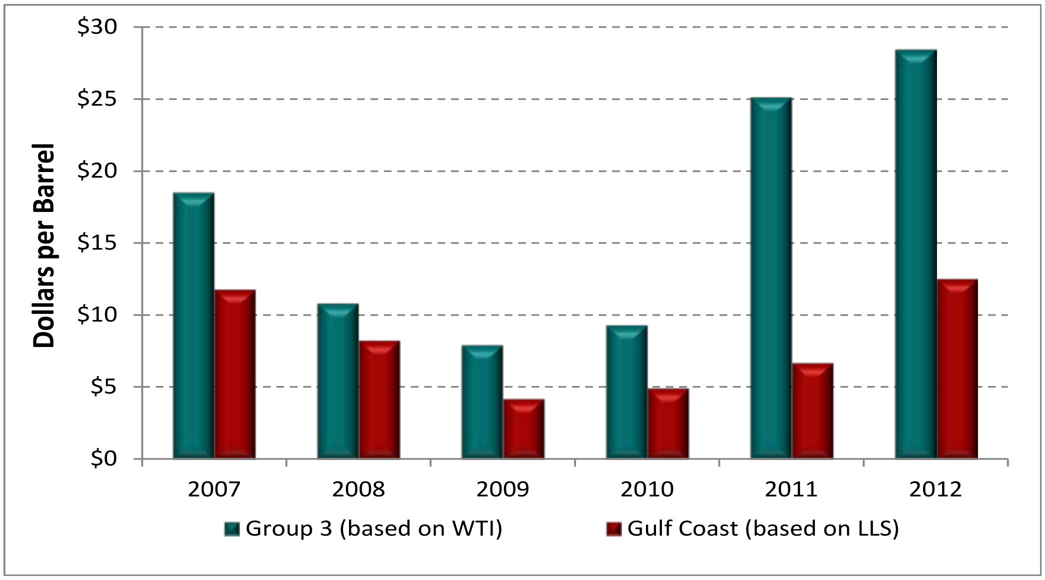


Source: Bloomberg 2012.

Note: Bloomberg WTI pricing (ticker symbol: USCRWTIC Index). Bloomberg LLS pricing (ticker symbol: USCRLLSS Index). Danaher Oil Midcontinent unleaded gas pricing (ticker symbol: G3OR87PC Index). Bloomberg U.S. Gulf Coast reformulated blendstock for oxygenate blending pricing (ticker symbol: RBOBG87P Index). Bloomberg Chicago conventional blendstock for oxygenate blending pricing (ticker symbol: CHOR87PC Index).

bbl = barrel, LLS = Light Louisiana Sweet crude, USGC = U.S. Gulf Coast, WTI = West Texas Intermediate crude.

Figure 2 Average Crude Oil and Gasoline Price Spreads, dollar/bbl spread



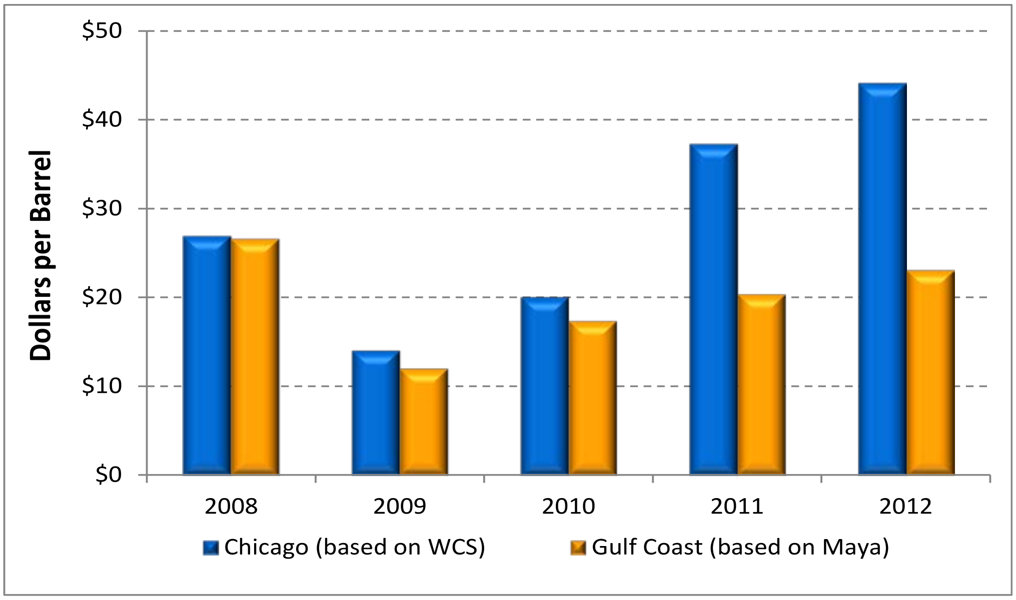
Source: Bloomberg 2012.

Notes:

1. Bloomberg WTI pricing (ticker symbol: USCRWTIC Index). Danaher Oil Midcontinent unleaded gas pricing (ticker symbol: G3OR87PC Index). Danaher Oil Midcontinent ultra-low sulfur diesel pricing (ticker symbol: G3ORUTLS Index). Bloomberg LLS pricing (ticker symbol: USCRLLSS Index). Bloomberg U.S. Gulf Coast reformulated blendstock for oxygenate blending pricing (ticker symbol: RBOBG87P Index). Bloomberg U.S. Gulf Coast ultra-low sulfur diesel pricing (ticker symbol: DIEIGULP index).
2. Group 3 margins are a 3-2-1 spread using WTI crude. Gulf Coast area margins are a 3-2-1 spread using LLS crude.

LLS = Light Louisiana Sweet crude, WTI = West Texas Intermediate crude.

Figure 3 Refinery Margins: Group 3 and Gulf Coast Area



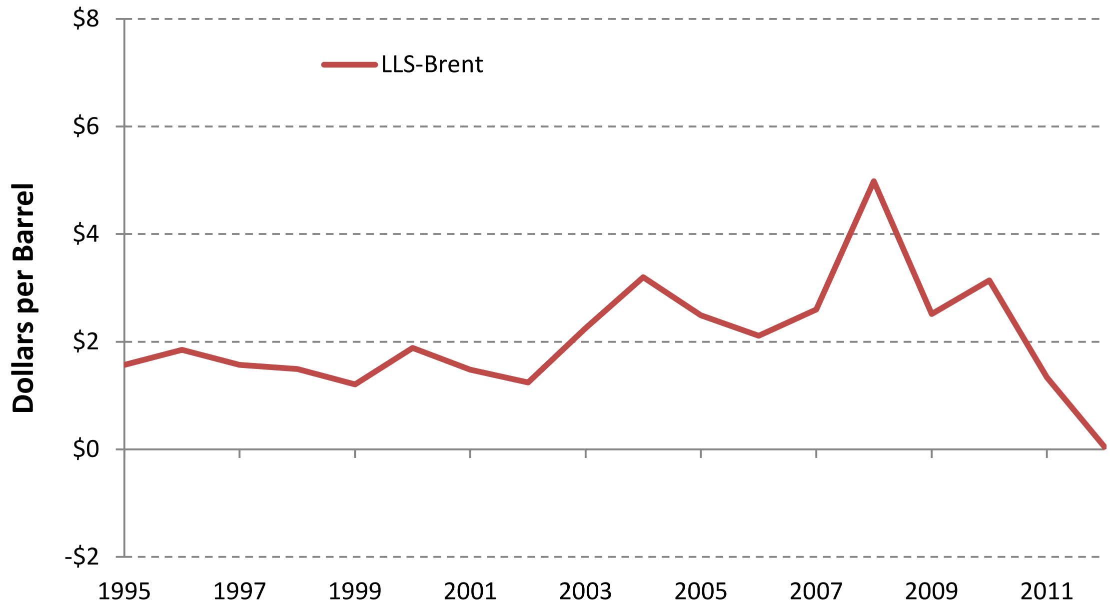
Source: Bloomberg 2012.
Notes:
1. Bloomberg Maya pricing (ticker symbol: LACRMAUS Index). Bloomberg Chicago conventional blendstock for oxygenate blending pricing (ticker symbol: CHOR87PC Index). Bloomberg Chicago ultra-low sulfur diesel pricing (ticker symbol: CHORUTLS Index). Bloomberg Western Canada Select (WCS) crude pricing (ticker symbol: USCRWCAS Index). Bloomberg U.S. Gulf Coast reformulated blendstock for oxygenate blending pricing (ticker symbol: RBOBG87P Index). Bloomberg U.S. Gulf Coast ultra-low sulfur diesel pricing (ticker symbol: DIEIGULP Index).
2. Chicago margins are a 3-2-1 spread using delivered WCS crude. Gulf Coast margins are a 3-2-1 spread using delivered Maya crude.

WCS = Western Canada Select crude.

Figure 4 Refinery Margins: Chicago and Gulf Coast Area

The WTI crude price discount versus Gulf Coast area prices described above may be reduced after the new pipelines from Cushing to the Gulf Coast area are constructed. In fact, recent activity to move Bakken crude into Louisiana by rail, and to move Eagle Ford shale oil from South Texas into Louisiana via the Louisiana Offshore Oil Port (LOOP)[12] have appeared to result in a reduction in the long-term spread relationship between LLS and Brent-based supply (see Figure 5). Historically, Brent crude oil has had a $2 to $3 per barrel discount to LLS to account for transportation costs from Europe to the Gulf Coast. It is important to recognize that the recent compression of the spread between LLS and Brent crude indicates that cargoes of Brent-based crude oil will appear more expensive to refiners in the Gulf Coast after transportation costs are added. This compression is the economic driver behind the reductions in imports of light sweet crudes into the Gulf Coast already being seen.

[12] LOOP is the Louisiana Offshore Oil Port which is typically used to offload foreign cargoes of crude oil into the Louisiana crude pipeline systems to refiners.



Source: Bloomberg 2012.
Note: Bloomberg LLS pricing (ticker symbol: USCRLLSS Index). Bloomberg Brent pricing (ticker symbol: EUCRBRDT Index).
LLS = Light Louisiana Sweet crude.

Figure 5 Annual Average Price Spreads, LLS minus Brent, dollars/barrel

Furthermore, a recent document published by EIA supports the contention that increased supply into the market could lead to lower crude prices:

> The availability of domestic light crude to U.S. Gulf Coast refineries is expected to continue increasing as pipeline expansions allow more crude to move to the U.S. Gulf Coast. This increased light crude supply could exert downward pressure on Gulf Coast light crude prices (EIA 2012b).

The extent of the potential Gulf Coast area crude oil price discounts versus foreign crudes would be unlikely to approach the deep discounts seen at Cushing in the past 2 years. This is because, as discounts grow with added supply (using simple supply and demand economics), Gulf Coast area refiners may see incentives to reconfigure their processing capacity to increase their ability to process lighter crude oil and produce more gasoline and diesel fuel. In addition, East Coast refiners may see incentive to use Jones Act[13] vessels to move crude to East Coast refineries. The decline in the cost differential between LLS and Brent would likely continue to be a discount (LLS at or below Brent price) as more domestic crude reaches the Gulf Coast area. The discount would then periodically rise and fall as refiners adapt to the new price structure.

This rationale could also apply to the impact of additional heavy crude supply as projects are completed that increase the transport capacity for WCSB heavy crudes to the Gulf Coast area.

[13] The Jones Act (Section 27 of the Merchant Marine Act of 1920) regulates U.S. maritime commerce by requiring ships moving between two U.S. ports to be United States-flagged, built in the United States, owned by U.S. citizens, and crewed by U.S citizens and permanent residents.

Increased WCSB heavy crude volumes into the Gulf Coast area market could also put downward pressure on volumes of heavy Venezuelan, Mexican, Brazilian, and Columbian crudes; those suppliers may have to reduce their prices to compete with the new WCSB heavy crude volumes. With both light and heavy crudes pushing prices of similar grades of foreign crude down, the relative spread between light and heavy crudes may, over time, be stable.[14]

5.0 PIPELINE AND RAIL COST INFORMATION

The following provides information related to the costs of transporting crude oil via pipeline and rail infrastructure. Table 3 and Table 4 show pipeline transport costs based on various delivery levels commitment for heavy and light crude. Table 5 shows estimated costs for crude oil transport using rail infrastructure.

Table 3 Impact of Pipeline Commitment Period on Tariffs: Example 1

	TransCanada ($/bbl)		Seaway ($/bbl)
Heavy Crude	**Hardisty to Cushing**	**Hardisty to Wood River**	**Cushing to Gulf Coast Area**
Uncommitted	$9.73	$8.75	$4.32
5 years	NA	NA	$3.57
10 years	$6.63	NA	$3.32
20 years	$6.23	$5.42	NA

Sources: TransCanada 2012a and 2012b; Seaway 2012.

Note: Seaway committed tariffs based on commitment of 0 to 99,999 barrels per day. For currency conversion, US$1=CAN$0.98. For volume conversion, 1 cubic meter = 6.2898 barrels.

bbl = barrels; NA = not applicable.

Table 4 Impact of Pipeline Commitment Period on Tariffs: Example 2

	TransCanada ($/bbl)		Seaway ($/bbl)
Light Crude	**Hardisty to Cushing**	**Hardisty to Wood River**	**Cushing to Gulf Coast Area**
Uncommitted	$9.02	$8.00	$3.82
5 years	NA	NA	$3.07
10 years	$6.03	NA	$2.82
20 years	$5.64	$4.78	NA

Sources: TransCanada 2012a and 2012b; Seaway 2012.

Note: Seaway committed tariffs based on commitment of 0-99,999 barrels per day. For currency conversion, US$1=CAN$0.98. For volume conversion, 1 cubic meter = 6.2898 barrels.

bbl = barrels, NA = not applicable.

[14] However, if the proposed project is not approved, and other pipeline projects connecting PADD 2 and the WCSB to the Gulf Coast area do not go forward, the higher cost of rail movements of heavy crude may put minimal pressure on heavy crude prices, in which case the spread between light and heavy would be expected to narrow.

Table 5 Estimated Delivered Cost via Rail on Selected Movements of Crude[a]

Origin	Destination	Rail Route	Dollars per Barrel
Dilbit			
Lloydminster, SK	Port Arthur, TX	CPRS-St. Paul-UP	$15.62
Lloydminster, SK	Stroud, OK[b]	CN-Superior, WI-UP (SLWC delivery)	$13.13
Syncrude			
Lloydminster, SK	Port Arthur, TX	CPRS-St. Paul-UP	$14.63
Bakken			
Epping, ND	Stroud, OK[b]	BNSF (SLWC deliver)	$7.48
Epping, ND	Philadelphia, PA	BNSF-Chicago-CSXT	$10.55
Epping, ND	St. John, NB	BNSF-EOLA, IL-CN-St. Jean, PQ-MMA	$13.72

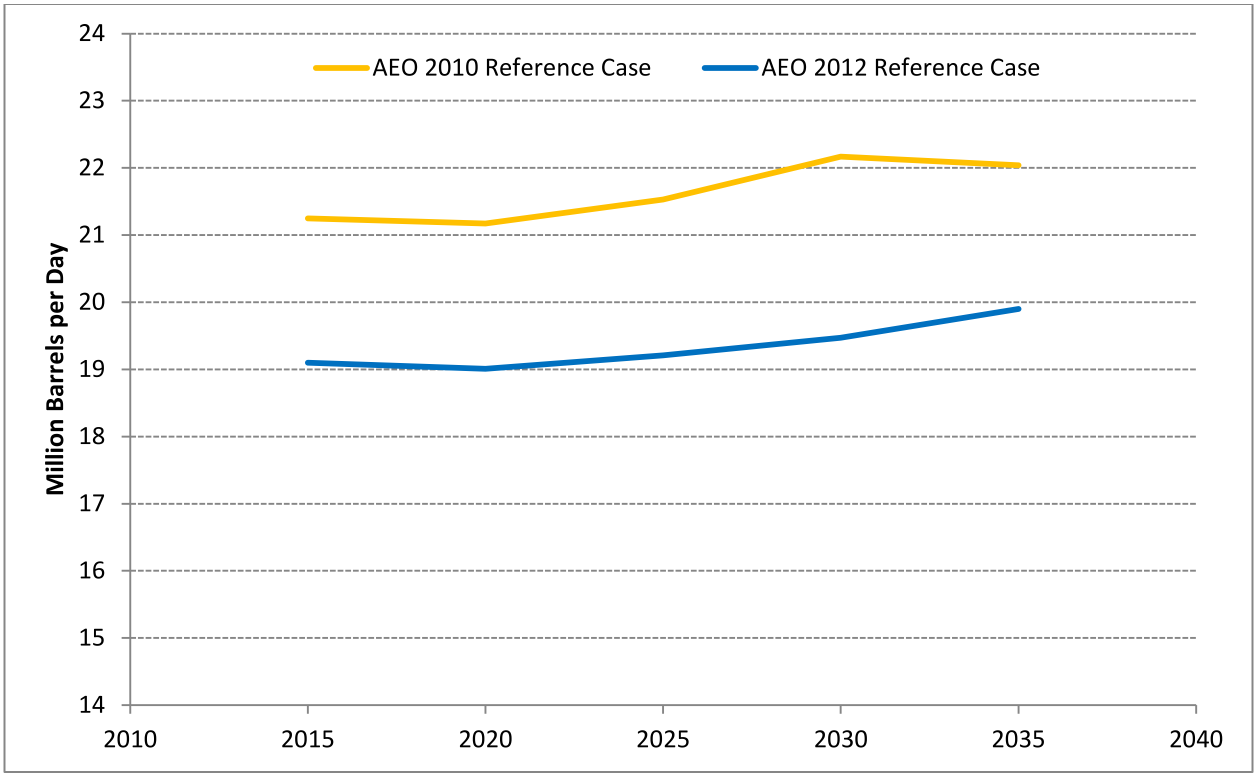
Source: Hellerworx Inc. 2013.

[a] Estimated delivered cost includes rail rate from origin to destination, loading railcars at origin rail terminal, unloading cars at destination rail terminal, and full service lease for rail tank car. Rail rate estimates developed by calculating Long Run Variable Cost and applying an estimated contribution margin of 137 percent (average for 2010). The rail rate estimates are not published tariffs; some crude oil rates are contained in published tariffs but crude would move mostly on contract rates with commitments of between 3 to 7 years.
[b] Stroud, Oklahoma, is the closest rail terminal to Cushing (approximately 17 miles via pipeline).

BNSF = Burlington Northern-San Francisco Railway, CN = Canadian National, CPRS = Canadian Pacific Railway System, CSXT = CSX Transportation, dilbit = diluted bitumen, EOLA = Eola Yard, a BNSF Railway yard in Aurora, Illinois, IL = Illinois, MMA = Montreal, Maine & Atlantic Railway, Ltd., NB = New Brunswick, ND = North Dakota, OK = Oklahoma, PA = Pennsylvania, PQ = the Province of Quebec, now abbreviated QC, SLWC = Stillwater Central Railroad, SK = Saskatchewan, TX = Texas, UP = Union Pacific Railroad Company, WI = Wisconsin.

6.0 COMPARISON OF U.S. PRODUCT DEMAND, ANNUAL ENERGY OUTLOOK 2010 AND 2012

The difference in U.S. product demand for total liquids is shown in Figure 6. Total liquids includes liquefied petroleum gases (LPG), E85, motor gasoline, jet fuel, distillate fuel oil, residual fuel oil, and other fuels (including aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, etc.). Lower U.S. demand forecasts in 2012 are a significant driver of U.S. import and export trends. Looking at projections for 2012, 2015, and 2020, import/export volume ratios in the AEO 2010 forecast range from 1.65 to 1.81. Comparatively, import/export ratios for the same time period range from 0.95 to 1.01 in the AEO 2012 forecast.



Source: EIA 2010, EIA 2012.
AEO = Annual Energy Outlook.

Figure 6 Comparison of AEO 2010 and 2012 U.S. Product Demand – Total Liquids

7.0 CRUDE BY RAIL LOADING, OFF-LOADING, AND TRANSLOADING FACILITIES

In this section, the following tables (Table 6 through Table 14) provide specific information to supplement the narrative and figures (1.4.6-4 and 1.4.6-5) in the Market Analysis related to crude by train loading, off-loading, and transloading facilities.

Table 6 PADD 1 Crude by Rail Offloading

Crude-by-Rail Terminal/Operator/Owner(s)	Estimated Capacity (bpd)	Estimated In-Service Date
Enbridge Rail/Canopy Prospecting/Eddystone Rail Company/ Philadelphia, PA	60,000	2014
Buckeye Partners, L.P./Albany NY Terminal/ Albany, NY	135,000	In service
Carlyle Refinery/Philadelphia Energy Solutions/ Philadelphia, PA	140,000	2013
Genesis Energy, L.P./Walnut Hill Terminal/Walnut Hill, FL/ Saraland Terminal Mobile, AL	60,000	In service
Global Partners LP/Albany, NY	160,000	In service

Crude-by-Rail Terminal/Operator/Owner(s)		Estimated Capacity (bpd)	Estimated In-Service Date
NuStar Energy L.P./Paulsboro, NJ		30,000	2013
PBF Energy/Delaware City, DE		110,000	In service
Plains All American Pipeline, L.P./Yorktown, VA		130,000	2013
Sunoco/Eagle Point Terminal/Eagle Point, NJ		20,000	In service
U.S. Development Group/East Coast, (Undisclosed)		65,000	2014
Irving Refinery/St. John, NB		90,000	In service
	Total	**1,000,000**	

Source: Hart 2012a; Company and Media Reports.
bpd = barrels per day, AL = Alabama, bpd = barrels per day, DE = Delaware, FL = Florida, L.P. = Limited Partnership, LP = Limited Partnership, NB = New Brunswick, NJ = New Jersey, NY = New York, PA = Pennsylvania, PADD = Petroleum Administration for Defense District, VA = Virginia.

Table 7 PADD 2 Bakken Rail Loading

Crude-by-Rail Terminal/Operator/Owner(s)	Estimated Capacity (bpd)	Estimated In-Service Date
Hess/Tioga, ND - Phase 1	55,000	2012
Hess/Tioga, ND - Phase 2	75,000	2014
Lario Logistics - Bakken Oil Express Phase 1/Dickinson, ND	100,000	2011
Lario Logistics - Bakken Oil Express Phase 2/Dickinson, ND	150,000	2012
Lario Logistics - Bakken Oil Express Phase 3/Dickinson, ND	250,000	2014
Savage-KCS/Trenton, ND	90,000	2012
Musket, Dore, ND	60,000	2012
Watco - KMEP/Dore, ND	70,000	2012
Enbridge Berthold Phase 2/Berthold, ND	70,000	2013
Enbridge Berthold Phase 1/Berthold, ND	10,000	2012
Plains All American Pipeline Ross Complex Phase 1/Ross, ND	20,000	2011
Plains All American Pipeline Ross Complex Phase 2/Ross, ND	45,000	2012
U.S. Development Group - CP Van Hook Phase 1/ Van Hook Township, ND	35,000	1Q2012
U.S. Development Group - CP Van Hook Phase 2/ Van Hook Township, ND	35,000	4Q2012
Great Northern Mid-Stream Phase 1/Fryburg, ND	70,000	2012
Great Northern Mid-Stream Phase 2/Fryburg, ND	70,000	2013
Watco - EOG/Stanley, ND	65,000	2009
Rangeland COLT/Epping, ND	120,000	2012
88 Oil - ND Port Services/Minot, ND	30,000	2008
Donnybrook, ND	30,000	2008
Stampede, ND	30,000	2008
Dakota Plains Transport Solutions (CP) Phase 1/New Town, ND	20,000	2010
Dakota Plains Transport Solutions (CP) Phase 2/New Town, ND	30,000	2011

Crude-by-Rail Terminal/Operator/Owner(s)		Estimated Capacity (bpd)	Estimated In-Service Date
Basin Transload Phase 1/Zap, ND		5,000	2010
Basin Transload Phase 2/Zap, ND		5,000	2013
	Total	**1,540,000**	

Source: Hart 2012a; Company and Media Reports.
bpd = barrels per day, CP = Canadian Pacific Railway System, EOG = EOG Resources, Inc., KCS = Kansas City Southern Railway Company, KMEP = Kinder Morgan Energy Partners LP, ND = North Dakota, PADD = Petroleum Administration for Defense District, Q = quarter.

Table 8 PADD 2 Non-Bakken Loading

Crude-by-Rail Terminal/Operator/Owner(s)		Estimated Capacity (bpd)	Estimated In-Service Date
Mercuria Energy Trading, Okeene, OK		30,000	2012
Logimarq Transloading - Marquis Energy Trading/Sayre, OK		30,000	2011
Oklahoma Dept. of Transportation (OKDOT) Farmrail Phase l/Sayre, OK		10,000	2011
OKDOT Farmrail Phase 2 /Sayre, OK		30,000	2013
Chesapeake Phase 1/ Westhorn, OK		10,000	2013
Chesapeake Phase 2/ Westhorn, OK		140,000	2016E
CrossTex Energy/Ohio Northern		55,000	2012
	Total	**305,000**	

Source: Hart 2012a; Company and Media Reports.
bpd = barrels per day, OK = Oklahoma, OKDOT = Oklahoma Dept. of Transportation, PADD = Petroleum Administration for Defense District.

Table 9 PADD 2 Rail to Marine Transloading Facilities

Crude-by-Rail Owners/Operators/Venture Partners		Estimated Capacity (bpd)	Estimated In-Service Date
Seacor Energy-GatewayTerminals / Sauget, IL		130,000	2011
Marquis Energy / Hayti, MO		45,000	2012
Marquis Energy / Hennepin, IL		35,000	2012
Seacor Energy-Gateway Terminals/ St. Louis, MO		40,000	2012
	Total	**250,000**	

Source: Hart 2012a; Company and Media Reports.
bpd = barrels per day, IL = Illinois, MO = Missouri, PADD = Petroleum Administration for Defense District.

Table 10 PADD 2 Stroud to Cushing Loading/Transloading/Offloading Facilities

Crude-by-Rail Terminal/Operator/Owner(s)		Estimated Capacity (bpd)	Estimated In-Service Date
EOG Stroud OK to Cushing OK		60,000	2011
Watco-KMEP I Dore Phase 1/Stroud, OK to and from Cushing		140,000	2012
Watco-KMEP I Dore Phase 2/Stroud, OK to and from Cushing		140,000	2015
	Total	**340,000**	

Source: Hart 2012a; Company and Media Reports.
bpd = barrels per day, EOG = EOG Resources, Inc., KMEP = Kinder Morgan Energy Partners LP, OK = Oklahoma, PADD = Petroleum Administration for Defense District.

Table 11 PADD 3 Rail Terminals

Gulf Coast Area Destination Terminals	Estimated Capacity (bpd)	Estimated In-Service Date
Cima Energy/Houston, TX	65,000	2011
GT Logistics GT Omni Port/Port Arthur, TX	125,000	2012
NuStar-EOG Initial Startup/St. James, LA	10,000	2011
NuStar-EOG Phase 2 Start/St. James, LA	60,000	2012
NuStar-EOG Phase 2 Realization Phase/St. James, LA	30,000	2013
NuStar-EOG Phase 3/St. James, LA	40,000	2013
U.S. Dev. Group Phase 1/St. James, LA	65,000	2011
Triafigura Texas Dock & Rail/Corpus Christi, TX	65,000	2013
Crosstex Energy, Phase 1, Riverside, LA	15,000	2012
Crosstex Energy, Phase 2, Riverside, LA	30,000	2015
Watco Greens Port Industrial Park/Houston, TX	65,000	2011
U.S. Dev. Group Phase 2/St. James, LA	65,000	2012
Sunoco, Nederland, TX	15,000	2012
CN/Arc, Mobile, AL	25,000	2013
Genesis Energy, Natchez, MS	10,000	2013
Genesis Energy, Baton Rouge, LA	70,000	2Q 2014
Arc Terminals LP, Saraland, AL	75,000	2013
Estimated Total	**830,000**	
Permian Origination Loading Crude-by-Rail Sendout Terminals		
EOG San Angelo, TX	5,000	2012
Atlas Oil - Phase 1/Odessa, TX	10,000	2011
Atlas Oil - Phase 2/Odessa, TX	25,000	2014
Cetane Energy & Murex N.A., Ltd./Carlsbad, NM	75,000	2012
Martin Midstream/KMEP Pecos Valley Phase 1/Pecos, TX, Permian	65,000	2012
Martin Midstream/KMEP Pecos Valley Phase 2/Pecos, TX, Permian	145,000	2013
Martin Midstream/KMEP Pecos Valley Phase 3/Pecos, TX, Permian	120,000	2014
Martin Midstream/KMEP Pecos Valley Phase 4/Pecos, TX, Permian	90,000	2015
Mercuria Energy Trading Panhandle/Panhandle, TX, Permian	30,000	2013
Iowa Pacific Holdings LLC/LogiBio LLC, Lovington, NM	NA	2013
Atlas Oil Company, Monahans, TX	NA	Operational
Atlas Oil Company, Odessa, TX	NA	2011
Atlas Oil Company, Albuquerque, NM	NA	2009
Estimated Total	**565,000**	

Gulf Coast Area Destination Terminals	Estimated Capacity (bpd)	Estimated In-Service Date
Eagle Ford Origination Loading Crude-by-Rail Sendout Terminals		
U.S. Development Group, Eagle Ford Crude Terminal/ Cotulla (Gardendale), TX	40,000	2011
EOG Resources/Hardwood, TX	25,000	2012
Atlas Oil Company, La Feria, TX	NA	Operational
Estimated Total	**65,000**	

Source: Hart 2012a; Company and Media Reports
bpd = barrels per day, AL = Alabama, EOG = EOG Resources, Inc., GT = GT Logistics LLC, LA = Louisiana, LLC = Limited Liability Company, LP = Limited Partnership, Ltd. = Limited, MS = Mississippi, N.A. = North America, NA = not applicable, NM = New Mexico, PADD = Petroleum Administration for Defense District, TX = Texas.

Table 12 PADD 4 Rail Loading

Crude-by-Rail Terminal	Estimated Capacity (bpd)	Estimated In-Service Date
U.S. Development Group, Niobrara Crude Terminal Phase 1/Carr, CO	35,000	2011
U.S. Development Group, Niobrara Crude Terminal Phase 2/Carr, CO	35,000	2012
Musket - Broe Group Great Western Industrial Park/Windsor, CO	15,000	2012
Watco Swan Ranch/Cheyenne, WY	65,000	2013
Plains All American, Tampa, CO	70,000	2013
Granite Peak Development/Cogent Energy Solutions/Casper, WY	120,000	2013
Eighty-Eight Oil/Guernsey, WY	80,000	2013
Total	**420,000**	

Source: Hart 2012a; Company and Media Reports.
bpd = barrels per day, CO = Colorado, PADD = Petroleum Administration for Defense District, WY= Wyoming.

Table 13 PADD 5 Rail Offloading/Transloading

Crude-by-Rail Terminal/Operator/Owner(s)	Estimated Capacity (bpd)	Estimated In-Service Date
BP Cherry Point/Blaine, WA	20,000	2013
Alon USA/Bakersfield, CA	65,000	2012
Tesoro/Anacortes, WA	50,000	2012
Ferndale, WA	40,000	2014
Blaine, WA	60,000	2014
Grays Harbor, WA	20,000	2014
Undisclosed, Bakersfield Area, CA	6,5000	2015
U.S. Development Group/Bakersfield, CA	65,000	2015
Global Partners/Clatskanie, OR	Not Reported	2012
Targa Sound Terminal/Port of Tacoma, WA	120,000	2014
Total	**385,000**	

Source: Hart 2012a; Company and Media Reports
bpd = barrels per day, BP = British Petroleum, CA = California, OR = Oregon, PADD = Petroleum Administration for Defense District, WA = Washington.

Table 14 Canadian Rail Loading Facilities

Southern Pacific Resource Corp, Lynton, AB
Torq Transloading, Whitecourt, AB
Connacher Oil and Gas Ltd., Bruderheim, AB
Gibson Energy, Hardisty, AB
Torq Transloading, Tilley, AB
Dollard, SK
Lloydminster, SK
Altex Energy Ltd., Lashburn, SK
Altex Energy Ltd., Unity, SK
Estevan, SK
Bromhead, SK
Torq Transloading, Tribune, SK
Tundra Energy, CN, Cromer, MB
Ceres Global Ag. Corp, Northgate, SK

Source: Hart 2012a; Hart 2012b; Company and Media Reports.
AB = Alberta, CN = Canadian National Railway, MB = Manitoba, PADD = Petroleum Administration for Defense District, SK = Saskatchewan.

8.0 ESTIMATED WCSB CRUDE OIL TRANSPORT CAPACITY

The Supplemental EIS includes an evaluation of whether rail transport by itself could accommodate the projected growth in WCSB crude oil production. This consisted of an assessment of rail capacity growth that would be required if the pipeline was not constructed due to denial or some other reason, and if no additional pipeline capacity was constructed beyond what currently exists. In this scenario, all WCSB crude oil would be transported by current pipeline capacity plus existing and future rail capacity.

The approach used in this analysis was to first calculate the total amounts of both heavy and light crude from the WCSB projected to be available for export through 2030. The analysis used CAPP 2012 projections for WCSB production, to which was added an additional amount of tight oil production above CAPP forecasts to account for a potential increased outlook for tight oil as indicated in the International Energy Agency's World Energy Outlook (WEO) 2012 and other sources. Crude oil volumes projected to be refined in the WCSB, and therefore not available for export, were then subtracted to yield estimates for net export volumes.

Second, WCSB pipeline export capacity was estimated using CAPP 2012 data, with the addition of the Milk River and Rangeland pipelines which were not included in CAPP 2012. Current pipeline export capacity for light and heavy oil was estimated by aggregating the combined effective capacities of the existing pipelines shown in Table 15. Effective capacities were assumed to be 90% of nameplate capacities to estimate actual shipped volumes (Table 15). In addition, available pipeline export capacity was reduced by 100,000 bpd to account for the estimated volume of refined product that these pipelines ship. Rail export capacity was estimated based on trends in growth of crude oil transport described in the Market Analysis. Two scenarios for annual rail capacity growth were considered: 175,000 bpd and 200,000 bpd. Both rail scenarios assume a 2013 capacity of 200,000 bpd.

Table 15 Estimated Existing Western Canada Pipeline Capacity[a]

	Name Plate Capacity		Effective Capacity[a]	
	Light (thousand bpd)	Heavy (thousand bpd)	Light (thousand bpd)	Heavy (thousand bpd)
Enbridge	1,081	1,246	973	1,121
Express	98	182	88	164
TransMountain	240	60	216	54
Keystone Mainline	148	443	133	399
Milk River/Rangeland	50	165	45	149
Total	1,617	2,096	1,455	1,886
Total Combined Light and Heavy	3,713		3,342	

Source: Canadian Association of Petroleum Producers (CAPP) 2012 (Milk/Rangeland capacities estimated from CAPP 2012 information about Western Canadian Sedimentary Basin [WCSB] export to Petroleum Administration for Defense District [PADD] 4).
[a] Adjustment factors of 90% were applied to nameplate capacities to account for effective transport capacities.
bpd = barrels per day.

Finally, surplus capacity was calculated by subtracting WCSB production from WCSB pipeline and rail export capacity for various scenarios, including existing pipeline only (without any rail transport), existing pipeline plus rail growing annually at 175,000 bpd, and existing pipeline with rail growing 200,000 bpd annually.

The results are shown in Table 16. Under the existing pipeline-only scenario, total transport capacity is insufficient to meet export needs by 2016 for heavy crude oil, and immediately for light crude oil (the pipeline systems have some flexibility in allocating how much heavy and light crude is transported). Under the pipeline with 175,000 bpd rail growth scenario, surplus capacity is exhausted by 2020 and continues through the end of the assessment period in 2030. However, assuming existing pipeline capacity and growth in the 200,000 bpd rail capacity, a net surplus in shipping capacity is maintained throughout the assessment period, with the exception of 2025 where an approximately 100,000 bpd capacity deficit is projected. If a slightly higher rail growth is assumed (210,000 bpd), a surplus is maintained throughout the entire assessment period. This growth rate would require ongoing expansion of loading and unloading facilities and increased production of railcars in line with current growth rates. By comparison, actual growth in rail transport capacity in the Bakken is estimated to average approximately 230,000 bpd over the 3 years from 2011 through 2013, and East Coast offloading facilities have grown from zero to approximately 900,000 bpd in 2 years, providing support that such growth is viable (see Supplemental EIS Section 1.4, Market Analysis).

This assessment does not include the localized bottlenecks that are occurring in the Cushing, Oklahoma, and Chicago, Illinois, areas due to insufficient pipeline capacity to transport crude oil out of PADD 2. As discussed in the Market Analysis section of the Supplemental EIS, projects such as the Gulf Coast pipeline and the Seaway pipeline reversal (not included in this assessment's pipeline capacity estimates) are completed or underway to alleviate this constraint.

Table 16 Estimated Western Canadian Sedimentary Basin Crude Oil Transport Capacity

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total WCSB Crude Oil Production for Export (thousand bpd)																		
CAPP total heavy WCSB crude oil delivered to market	1,803	1,968	2,092	2,287	2,486	2,611	2,801	3,037	3,229	3,470	3,675	3,947	4,233	4,325	4,556	4,757	4,893	5,102
CAPP total light WCSB crude oil delivered to market	1,665	1,736	1,797	1,839	1,809	1,809	1,852	1,909	1,948	1,954	1,931	1,924	1,945	1,920	1,862	1,828	1,802	1,769
Tight oil production above CAPP forecasts[a]	200	200	200	250	300	300	350	400	400	400	400	400	400	400	350	350	350	300
Total processed West Canada refineries - heavy	220	250	270	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
Total processed West Canada refineries - light	350	350	350	360	360	360	370	370	370	370	370	370	370	370	370	370	370	370
Total WCSB heavy crude to export	1,583	1,718	1,822	2,027	2,226	2,351	2,541	2,777	2,969	3,210	3,415	3,687	3,973	4,065	4,296	4,497	4,633	4,842
Total WCSB light crude to export	1,515	1,586	1,647	1,729	1,749	1,749	1,832	1,939	1,978	1,984	1,961	1,954	1,975	1,950	1,842	1,808	1,782	1,699
Total WCSB Crude Oil Export Capacity (thousand bpd)																		
CAPP 2012 heavy pipeline capacity + Milk River/Rangeland	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890
CAPP 2012 light pipeline capacity + Milk River/Rangeland	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455
Less pipeline capacity dedicated to refined product transport	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)
Rail capacity with increase assumed to be 175,000 bpd each year	200	375	550	725	900	1,075	1,250	1,425	1,600	1,775	1,950	2,125	2,300	2,475	2,650	2,825	3,000	3,175
Rail capacity with increase assumed to be 200,000 bpd each year	200	400	600	800	1,000	1,200	1,400	1,600	1,800	2,000	2,200	2,400	2,600	2,800	3,000	3,200	3,400	3,600
Surplus Transport Capacity (thousand bpd)																		
Total surplus pipeline capacity (heavy)	307	172	68	(137)	(336)	(461)	(651)	(887)	(1,079)	(1,320)	(1,525)	(1,797)	(2,083)	(2,175)	(2,406)	(2,607)	(2,743)	(2,952)
Total surplus pipeline capacity (light)	(160)	(231)	(292)	(374)	(394)	(394)	(477)	(584)	(623)	(629)	(606)	(599)	(620)	(595)	(487)	(453)	(427)	(344)
Total surplus pipeline and rail capacity (rail at 175,000)	347	315	325	215	170	220	122	(46)	(102)	(174)	(181)	(271)	(404)	(294)	(243)	(235)	(170)	(120)
Total surplus pipeline and rail capacity (rail at 200,000)	347	340	375	290	270	345	272	129	98	51	69	4	(104)	31	107	140	230	305

Source: Pipeline capacities and Western Canadian refinery throughputs from CAPP 2012; projected production from CAPP 2012.
[a] An adjustment to the CAPP forecast to reflect the potential for higher production from tight oil formations as indicated by WEO.
bpd = barrels per day, CAPP = Canadian Association of Petroleum Producers, WCSB = Western Canadian Sedimentary Basin, WEO = World Energy Outlook.

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9.0 TRANSPORT COSTS FROM THE GULF COAST AREA TO ASIAN PORTS

Table 17 examines the costs of crude oil transport from the Gulf Coast area (Houston) to three main Asian ports. The information provided supplements the narrative provided in the Market Analysis related to costs for routes to Asian Markets.

Table 17 U.S. Gulf Crude Oil Exports, 2015 Outlook, VLCC and Suezmax[a]

	VLCC			Suezmax		
from	Houston	Houston	Houston	Houston	Houston	Houston
to	Dalian	Ningpo	Ulsan	Dalian	Ningpo	Ulsan
via	Cape/Cape	Cape/Cape	Cape/Cape	Panama	Panama	Panama
Cargo Size (MT)	280,000	280,000	280,000	130,000	130,000	130,000
Cargo Size (bbl)	1,904,000	1,904,000	1,904,000	884,000	884,000	884,000
Total Voyage Days	101	98	100	65	66	62
Freight Subtotal	$9,341,148	$8,941,148	$8,741,148	$5,945,852	$5,964,190	$5,678,829
Reverse Lightering	$800,000	$800,000	$800,000	$400,000	$400,000	$400,000
Total Freight	$10,141,148	$9,741,148	$9,541,148	$6,345,852	$6,364,190	$6,078,829
$/MT	$36.22	$34.79	$34.08	$48.81	$48.96	$46.76
$/bbl	$5.33	$5.12	$5.01	$7.18	$7.20	$6.88

Source: Poten and Partners 2013.
[a]Suezmax is a naval architecture term for the largest ship measurements capable of transiting the Suez Canal in a laden condition.
bbl = barrels, MT = metric tons, VLCC = very large crude carrier.

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ATTACHMENT

Department of State Memo: The North American Oil Market Outlook, January 4, 2013

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Department of Energy
Washington, DC 20585
January 4, 2013

MEMORANDUM FOR: DAVID SANDALOW
ASSISTANT SECRETARY FOR POLICY AND INTERNATIONAL AFFAIRS

FROM: ADAM E. SIEMINSKI
ADMINISTRATOR
U.S. ENERGY INFORMATION ADMINISTRATION

SUBJECT: THE NORTH AMERICAN OIL MARKET OUTLOOK

This memorandum responds to your request for an overview of the latest U.S. Energy Information Administration's (EIA) outlook for North American oil markets through 2025 and changes in the outlook over the past several years. The requested information is provided below, reflecting comparisons of projections in the *Annual Energy Outlook 2013* (AEO2013) Reference case issued in December 2012 to those in prior AEO editions.

The AEO2013 Reference case reflects some important updates, including more rapid near-term growth in U.S. tight oil production, a lower near-term trajectory for oil prices, and reduced U.S. gasoline demand due to higher vehicle efficiency. However, these updates do not alter some of the major implications of earlier projections, including continued U.S. dependence on imported crude oil supplies, growing global demand, long-term rising oil prices, growth in Canadian oil sands production, and continued demand for heavy crude by U.S. Gulf Coast refiners even as traditional sources from Mexico and Venezuela continue their recent declines. Key observations regarding demand and supply are summarized below.

Demand:

- The AEO2013 global demand projection is 105.3 million barrels per day in 2025, 3.7% higher than the AEO2012 projection and 1.6% above the AEO2011 projection. Nearly all of the growth in global liquids demand in of these AEO editions is attributable to non-OECD Asia and the Middle East.
- The AEO2013 U.S. demand projection is 19.5 million barrels per day for 2025, 1.6% higher than the AEO2012 projection and 7.1% below the AEO2011 projection. The increase in AEO2013 relative to AEO2012 largely reflects a rise in energy-intensive manufacturing which raises petroleum use in the form of natural gas liquids and diesel fuel for trucks even as projected gasoline use is reduced by new fuel economy standards.

Supply, Imports, and Refining:

- AEO2013 projects U.S. crude oil production of 7.5 million barrels per day in 2019, 13% above the AEO2012 projection. However, tight oil production declines after 2020 as development moves into lower-productivity areas, and the AEO2013 projection for U.S. crude production beyond 2025 is similar to that in AEO2012. AEO2011 has a somewhat lower production profile than either AEO2013 or AEO2012.
- In AEO2013, as in AEO2012 and AEO2011, the United States remains a significant net importer of petroleum in 2025 and beyond, with about one-third of U.S. demand satisfied by imports in 2025.
- In AEO2013, as in AEO2012 and AEO2011, growth in Canadian oil sands remains a key factor in maintaining robust non-OPEC supply over the course of the next several decades. Projected levels of total Canadian production in 2025 are in a narrow band from 5.3 and 5.6 million barrels per day across these three AEOs.
- AEO2013, AEO2012, and AEO2011 projections for Mexico's oil production in 2025 are very similar, falling into a range of 1.3 to 1.6 million barrels per day. Projected 2025 production in all three AEO editions is below the current level.
- With U.S. Gulf Coast refineries optimized for the use of heavy/sour crude oil, the regional demand for heavier grades of oil in the U.S. Gulf Coast remains strong through 2025. Continuing recent trends, heavy oil supplies from Mexico and Venezuela continue to decline.

Background
The *Annual Energy Outlook 2013* (AEO2013) Reference case published in December 2012 presents long-term projections of energy supply, demand, and prices through 2040 based on results from EIA's National Energy Modeling System. The complete AEO2013 to be released in the spring of 2013 will include a full range of cases exploring key uncertainties in the Reference case.

Oil Demand
The increase in EIA's Reference case projection for 2025 global oil demand between AEO2012 and AEO2013 is attributable to a more robust economic growth outlook for developing nations outside the Organization for Economic Cooperation and Development (OECD) and somewhat lower projections for oil prices over the next decade. The difference in global demand attenuates by 2035 (110.3 million barrels per day in AEO2013 against 109.5 million barrels per day in AEO2012) but in both cases EIA sees continuing growth in long-term world liquid fuels consumption despite rising world oil prices. Nearly all of the global increase in total liquids consumption is projected for the nations of non-OECD Asia and the Middle East, where strong economic growth and, in the case of the Middle East, access to ample and relatively inexpensive domestic resources, drive the increase in demand.

AEO2013 incorporates the new efficiency standards for light-duty vehicles in the United States through the 2025 model year, which reduces gasoline use in the transportation sector by 0.5 million barrels per day in 2025 and by 1.0 million barrels per day in 2035 in AEO2013 compared to the AEO2012 Reference case. As noted above, a rise in energy-intensive manufacturing that raises petroleum use in the form of natural gas liquids and diesel fuel for trucks has opposing effects on the demand for petroleum products. Overall U.S. petroleum product demand is relatively flat over the next 25 years in both the AEO2013 and AEO2012 projections.

Oil Supply
U.S. production of crude oil in the AEO2013 reference case increases from 5.7 million barrels per day in 2011 to 7.5 million barrels per day in 2019, 13% higher than in AEO2012. Despite a decline after 2019, U.S. crude oil production remains above 6.0 million barrels per day through 2040. Higher volumes from increased onshore oil production come predominantly from tight (very low permeability) formations. In AEO2013, onshore tight oil production accounts for 51% of total lower 48 states onshore oil production in 2040, up from 33% in 2011. Offshore crude oil production trends upward over time, fluctuating between 1.4 and 1.8 million barrels per day, as the pace of development quickens and new large development projects, predominantly in the deep and ultra-deep portions of the Gulf of Mexico, are brought into production.

The faster growth of tight oil production through 2020 in AEO2013 results in higher domestic crude oil production than forecast in AEO2012 throughout most of the projection. Tight oil production declines after 2020 as more development moves into lower-productivity areas (with lower initial production rates and flatter decline curves), resulting in flattening of production after 2030. Total U.S. liquids production in AEO2013 is higher than in AEO2012 due to increased tight oil production through 2025; however, lower production of biofuels and natural gas plant liquids, as well as the decline in tight oil production beginning in 2021, results in lower levels of total domestic liquids production after 2025 in AEO2013 than in AEO2012.

EIA's AEO2013 Reference case projects the Organization of the Petroleum Exporting Countries' (OPEC) share of total global supply to increase from 40.0% in 2011 to 44.2% in 2040. The AEO2012 estimated OPEC's share at 41.3% in 2025, while the AEO2013 pushes OPEC's share higher to 42.2% in 2025. Thus, recent optimism regarding U.S. production prospects does not challenge OPEC's role, or mitigate the robustness of market pressures to increase all sources of non-OPEC supply. A number of non-OECD producers, including Russia and other countries within the former Soviet Union, as well as Brazil, China, and a host of small African producers, are expected to see their combined share of total supply fall by an amount roughly equal to the OPEC increase between 2011 and 2040.

U.S. Imports

In both the AEO2012 and 2013, the United States remains a significant net importer of petroleum in 2025 and beyond, with about one-third of U.S. demand satisfied by net imports. In the AEO2013 reference case, U.S. net imports of liquids in 2025 are projected at 7.1 million barrels per day, the same level as in AEO2012, but 2.1 million barrels per day lower than had been projected in AEO2011. U.S. dependence on net imports of liquid fuels declines in the AEO2013 Reference case, primarily as a result of increased domestic oil production. Net liquid fuels imports as a share of total U.S. liquid fuel use exceeded 60% in 2005 before dipping below 50% in 2010 and falling further to 45% in 2011. The projected net import share in the AEO2013 Reference case bottoms at 34% in 2019 and then rises to about 37% in 2040, due to a decline in domestic production of tight oil that begins in about 2021. Differences between the AEO2013 and AEO2012 forecasts for U.S. net dependence on oil imports in 2025 and beyond are relatively minor.

U.S. Gulf Coast Refining

Many U.S. refineries are located close to crude oil production centers such as the Gulf Coast or near major population centers where much of the demand for petroleum products is concentrated (e.g., California and the areas near Philadelphia, New York City, and Chicago). Of the more than 17.5 million barrels per day of U.S. refinery capacity in 2012, about 44% is located along the Gulf Coast. Many Gulf Coast refineries have extensive secondary conversion capacity including hydrocrackers, cokers, and desulfurization units that enable the processing of heavy, high sulfur (sour) crude oils. Most East Coast refineries have less secondary conversion capacity, and, in general, they process crude oil with lower sulfur content and a lighter density (light sweet oil).

In recent years, oil production has risen dramatically in both the United States (light sweet crude, especially from the Bakken and Eagle Ford formations) and Canada (heavy sour grades from the Alberta oil sands). Although light sweet grades traditionally sell at a premium to heavy sour grades, inland light sweet oil that is subject to transportation bottlenecks has been heavily discounted in recent years. Refineries across the country are developing strategies to acquire and transport inland light sweet crude streams to replace more expensive imports of high-quality crude oil. At the same time, many Gulf Coast refiners are also seeking more access to Canadian oil to replace declining supplies of heavy crude from Mexico and Venezuela. As currently configured, many such refiners would experience lower utilization rates and produce less desirable product slates if they were to run light sweet crude, which also still sells at a premium to heavy grades in coastal locations.

AEO2013, AEO2012, and AEO2011 all project continued strong demand for heavy sour crudes from Gulf Coast refiners that are optimized to process such oil. While the AEO does not identify specific supply sources for the imported crude used by U.S. refiners, Canada is certainly a likely source for heavy grades. Importantly, the projection for rising Canadian oil sands production in the Reference case of all recent AEO editions is not predicated on the completion of any particular infrastructure project. Increased rail transport utilizing infrastructure that is already in place, appears to be a viable option for moving production over long distances to reach the Gulf Coast and other markets, as evidenced by the extremely rapid growth in the volume of rail shipments of domestic Bakken crude to a variety of markets over the past year. While rail shipment is somewhat more costly than pipeline shipment, the Bakken experience suggests that the absence of pipeline take away capacity will not forestall profitable production projects.

Reference Case Liquids Projections for 2025
Comparison of Recent Annual Energy Outlook Editions

	AEO2010	AEO2011	AEO2012	AEO2013
Total World Liquids Consumption (mmb/d)	100.7	97.1	101.5	105.3
OPEC Market Share (%)	41.6%	42.0%	41.3%	42.2%
U.S. Crude Oil Production (mmb/d)	6.1	5.9	6.4	6.8
Lower 48	5.4	5.5	6.0	6.4
Lower 48 Onshore	3.2	3.9	4.4	5.0
Lower 48 Offshore	2.1	1.6	1.6	1.5
Alaska	0.7	0.4	0.4	0.4
Other Petroleum and Non-Petroleum Supply excluding net imports (mmb/d)	4.9	5.8	5.8	5.6
U.S. Liquids Demand (mmb/d)	21.0	21.0	19.2	19.5
U.S. Net Liquids Imports (mmb/d)	9.8	9.2	7.1	7.1
U.S. Net Import Share of Demand (%)	47.1%	44.0%	37.0%	36.3%
Canada Oil Production (mmb/d)	5.1	5.3	5.5	5.6
Mexico Oil Production (mmb/d)	1.9	1.3	1.6	1.6

Source: U.S. Energy Information Administration