1.4 MARKET ANALYSIS

1.4.1 Introduction

This section examines the petroleum markets with a particular focus on changes in petroleum markets since the publication of the Final Environmental Impact Statement (Final EIS) on August 26, 2011. It assesses whether these changes alter the conclusion of the 2011 Final EIS market analysis, namely, that the proposed Project is unlikely to significantly affect the rate of extraction in the oil sands or in U.S. refining activities. Specifically, this section presents changes observed in the petroleum market since August 2011 and how such changes may impact the assessment made in the Final EIS. Several changes in the outlook for the crude oil market since August 2011 are accounted for in the Supplemental Environmental Impact Statement (Supplemental EIS) analysis. First, the outlook for U.S. demand for transportation fuel is now lower than it was in 2010 and 2011. Second, domestic production of crude oil has increased and is expected to continue increasing over the next 10 to 15 years. Third, the infrastructure for crude oil transportation in North America, including pipeline, rail, and other non-pipeline modes, is undergoing significant adaptations and increases in capacity. As explained below, these changes are not anticipated to alter the outlook for the crude oil market in a manner that would lead to a change in the key conclusions reached in the 2011 Final EIS. That conclusion is based, in part, on the following factors.

While the increase in U.S. production of crude oil and the reduced U.S. demand for transportation fuels will likely reduce the demand for total U.S. crude oil imports, it is unlikely to reduce demand for heavy sour crude at Gulf Coast refineries. Additionally, as was projected in the 2011 Final EIS, the midstream industry is showing it is capable of developing alternative capacity to move Western Canadian Sedimentary Basin (WCSB) (and Bakken and Midcontinent) crudes to markets in the event the proposed Project is not built. Specifically, it is moving to develop alternative pipeline capacity that would support Western Canadian, Bakken, and Midcontinent crude oil movements to the Gulf Coast and is increasingly using rail to transport large volumes of crude oil to East, West, and Gulf Coast markets as a viable alternative to pipelines. In addition, projected crude oil prices are sufficient to support production of essentially all Western Canadian (and U.S. tight oil[1]) crude oil projects, even with potentially somewhat more expensive transport options to market in the form of alternative pipelines and rail. Rail and supporting non-pipeline modes should be capable, as was projected in 2011, of providing the capacity needed to transport all incremental Western Canadian and Bakken crude oil production to markets if there were no additional pipeline projects approved.

Approval or denial of any one crude oil transport project, including the proposed Project, remains unlikely to significantly impact the rate of extraction in the oil sands, or the continued demand for heavy crude oil at refineries in the U.S. Limitations on pipeline transport would force more crude oil to be transported via other modes of transportation, such as rail, which would probably (but not certainly) be more expensive. Longer term limitations also depend upon whether pipeline projects that are located exclusively in Canada proceed (such as the proposed

[1] Tight oil refers to oil found in low-permeability and low-porosity reservoirs, typically shale. Bakken crude is considered tight oil. The technology of extracting crude oil from tight rock formations has only recently been exploited, but produces and supplies large quantities of crude oil into the domestic market. Shale oil extraction is a completely different process than oil sands development.

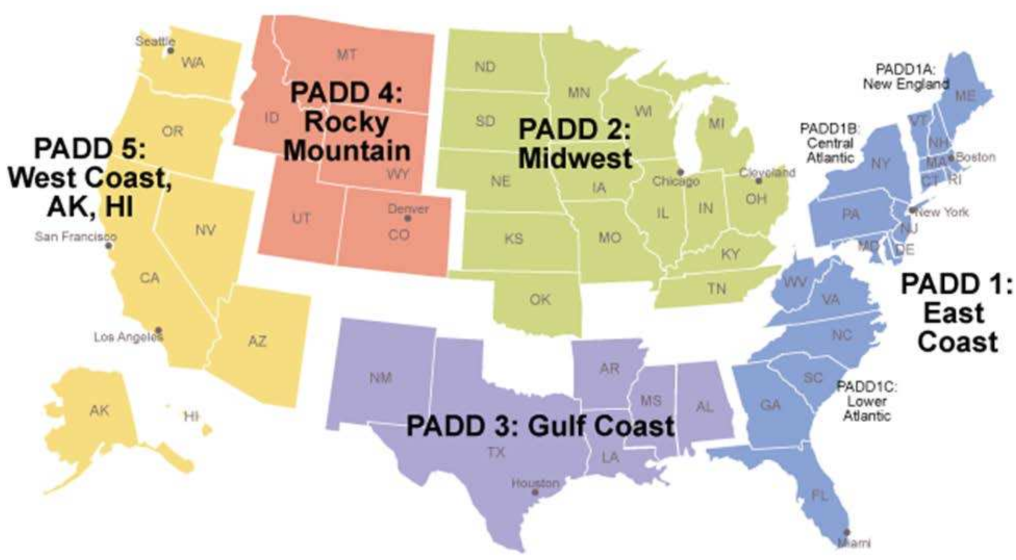
Northern Gateway, the Trans Mountain expansion, and the TransCanada proposal to ship crude oil east to Ontario on a converted natural gas pipeline).

If all such pipeline capacity were restricted in the medium-to-long-term, the incremental increase in cost of the non-pipeline transport options could result in a decrease in production from the oil sands, perhaps 90,000 to 210,000 barrels per day (bpd) (approximately 2 to 4 percent) by 2030. If the proposed Project were denied but other proposed new and expanded pipelines go forward, the incremental decrease in production could be approximately 20,000 to 30,000 bpd (from 0.4 to 0.6 percent of total WCSB production) by 2030. (As examined in section 4.15, such production decreases would be associated with a decrease in greenhouse gas emissions in the range of 0.35 to 5.3 $MMTCO_2e$ annually if all pipeline projects were denied, and in the range of 0.07 to 0.83 million metric tons carbon dioxide equivalent ($MMTCO_2e$) annually if the proposed Project were not built.)

Fundamental changes to the world crude oil market, and/or far reaching actions than are evaluated in this Supplemental EIS, would be required to significantly impact the rate of production in the oil sands.

1.4.2 PADD Regions in the U.S. Crude Oil Market

This section provides an explanation of the Petroleum Administration for Defense Districts (PADD) which are referenced throughout this market analysis. The 50 states and the District of Columbia are divided into five PADDs (Figure 1.4.2-1). 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.



Source: EIA 2012.

Figure 1.4.2-1 Petroleum Administration for Defense Districts (PADDs) Locations

The supply and refining profiles of the PADDs differ significantly. For example, PADD 3 and PADD 1 both import significant amounts of crude oil. PADD 3 imports a wider variety of crude oils, including over 2 million bpd of heavy crude oil, whereas PADD 1 imports are almost entirely of light and medium crude oils. Refiners in different PADDs largely serve the market for transportation fuels and other products in that that PADD, but there are inter-PADD transfers and refiners in the different PADDs are in competition with one another. In particular, PADD 3 refiners ship refined products to both PADD 1 and PADD 2. Additional information about the PADDs, including their refining and supply profiles, is included in Section 1.1 of Appendix C, Market Analysis Supplemental Information.

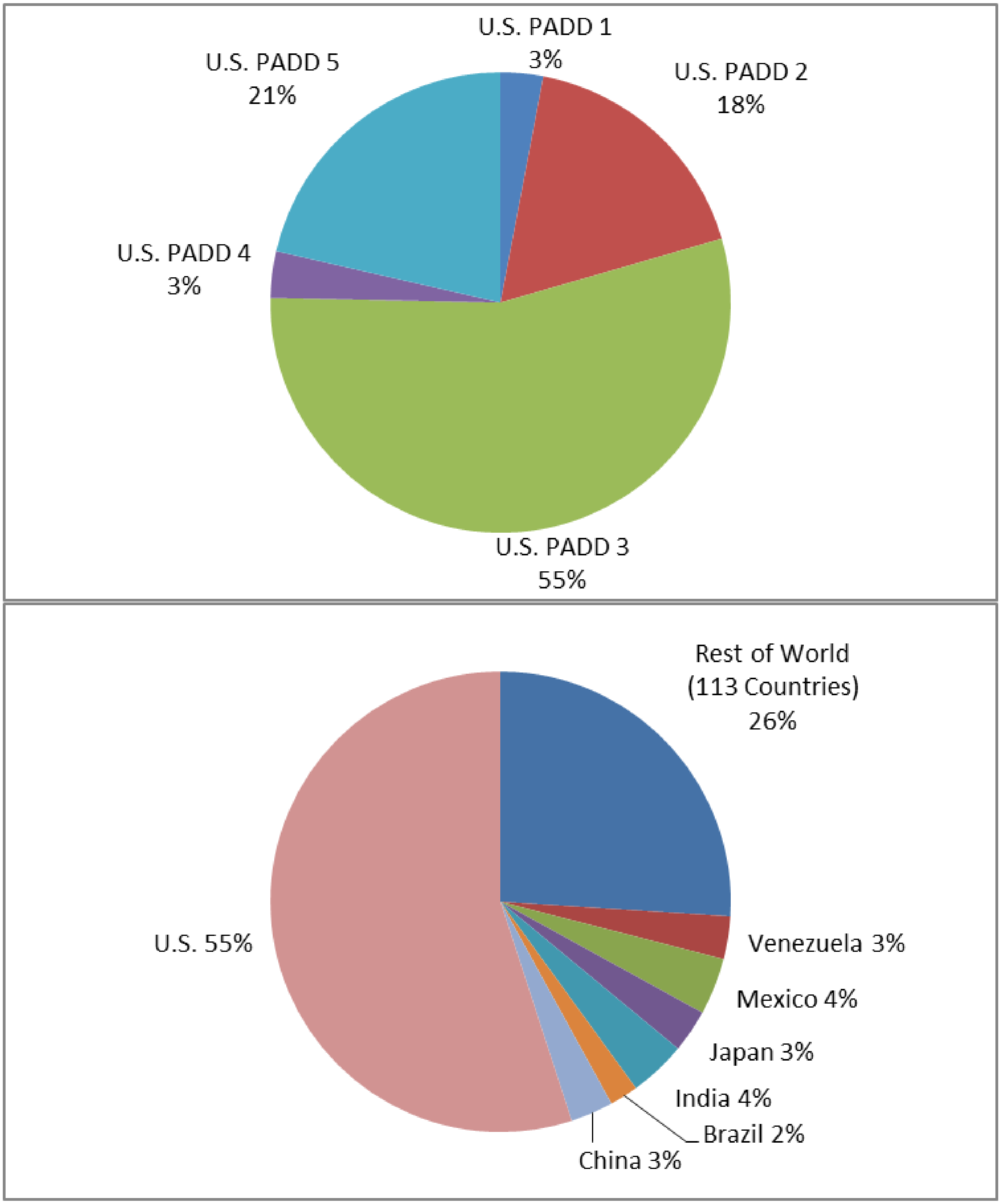
The Gulf Coast area[2] contains the single largest concentration in the world of refineries capable of processing heavy crudes. For example, the United States has over half of the world's coking[3] capacity, and the majority of this capacity is at Gulf Coast refineries (1.5 million bpd capacity in PADD 3 out of 2.74 million bpd nationwide in 2012, according to EIA data [see Figure 1.4.2-2]).

1.4.3 Market Analysis Presented in 2011 Final EIS

The assessment of the potential market impact of Keystone's previously proposed Keystone XL Project was presented in the August 26, 2011, Final EIS document. In presenting its assessment of the petroleum market outlook as seen in 2011, the U.S. Department of State (Department) drew on several studies. Notably, among the analyses and studies examined in that assessment was a study commissioned by the U.S. Department of Energy (USDOE) office of Policy and International Affairs. The USDOE commissioned the study to assist in the analysis of petroleum markets and how these markets might impact the project as proposed in 2011. The USDOE contracted with EnSys Energy and Systems, Inc. (EnSys) to develop a study of different North American crude oil pipeline scenarios through 2030. The market analysis in this Supplemental EIS focuses on an assessment of the crude oil market as it has evolved over the last 2 years. To understand the analysis in this Supplemental EIS it is necessary to understand the prior analysis in the Final EIS.

The study completed by EnSys in December 2010 assessed the potential impacts of several different scenarios of pipeline construction, including having or not having a Keystone XL pipeline, as then proposed, on U.S. refining, petroleum imports and exports, and on international crude oil markets and refining. Each pipeline scenario was evaluated against two different outlooks for U.S and global demand. A demand outlook is a projection of product demand[4] in a specified market for a given period of years.

[2] The Gulf Coast area refers to the region from Houston, Texas, to Lake Charles, Louisiana. Gulf Coast area refineries include 12 refineries on the Gulf Coast in Texas and three refineries in Lake Charles, Louisiana.
[3] Coking is a refinery operation that is used to process heavy crude oil. The process upgrades material into higher-value products and produces petroleum coke (EIA 2013).
[4] Product demand in this context refers to the full suite of refined petroleum products and biofuels. Refined petroleum products include gasoline, jet fuel, diesel, heating oil, residual fuels, and other products.



Source: Canadian Imperial Bank of Commerce (CIBC) 2012, EIA 2012b.

Note: U.S. coking capacity shown as percentage of 2.74 million barrels per stream day.

Figure 1.4.2-2 Relative Global and U.S. Coking Capacities

The first demand outlook used by EnSys was the 2010 EIA Annual Energy Outlook (AEO) Reference Case through 2030. The AEO is an annual report that is published by the USDOE's statistical agency, the EIA. The EIA provides independent and impartial energy information to the USDOE, other government agencies and the public. The second outlook employed by EnSys was a lower-demand scenario based on a U.S. Environmental Protection Agency (USEPA) study that assumed "more aggressive fuel economy standards and policies to address vehicle miles traveled" (EnSys 2010). The USEPA outlook projected that U.S. demand will be approximately 4 million bpd lower by 2030 than that projected in the AEO Reference Case. That USEPA study was used to generate a Low Demand Outlook using USDOE's Energy Technology Perspectives Model as applied by Brookhaven National Laboratory.

EnSys used these two demand outlooks to further examine the possible impacts associated with different scenarios regarding the construction of various pipelines. Besides looking at possible impacts associated with a decision to permit the Keystone XL pipeline, EnSys also looked at the impacts of other potential pipeline construction (such as Enbridge's Northern Gateway to the British Columbia coast, the Kinder Morgan Trans Mountain pipeline to the Vancouver region, and new pipelines within the United States). Finally, EnSys also looked at a "No Expansion" scenario that assumed pipeline capacity would be frozen at 2010 levels through 2030.

These different scenarios, and the market impacts associated with a denial or approval of the previously proposed Keystone XL pipeline, were evaluated using the EnSys WORLD Oil Refining Logistics and Demand model. The WORLD Oil Refining Logistics and Demand model (the WORLD Model) has been used since 1987 by the USDOE Office of Strategic Petroleum Reserve, and has been applied in analyses for organizations including the EIA, the USDOE, the USEPA, the World Bank, the American Petroleum Institute (API), and the Organization of the Petroleum Exporting Countries Secretariat.

The EnSys Report provided assessments of different scenarios of pipeline construction including scenarios with and without the Keystone XL Pipeline. These assessments were relevant to determining whether changes in upstream (extraction in the oil sands) and downstream (refining in the Gulf Coast area) activity should be considered indirect and cumulative impacts potentially caused by permitting the Keystone XL pipeline as then proposed.

The EnSys 2010 Assessment concluded that there was commercial demand for WCSB heavy crude oil in the Gulf Coast. The demand identified by the EnSys 2010 Assessment was sufficiently high that were a permit for the Keystone XL pipeline, as then proposed, denied, the market would likely respond by adding broadly comparable transport capacity over time. The EnSys 2010 Assessment forecasted that the demand for WCSB heavy crude from the oil sands would be such that irrespective of whether a permit for the Keystone XL pipeline, as then proposed, was granted, transport capacity in excess of that of the Keystone XL pipeline would likely be built.[5] The WORLD Model results indicated that under "business as usual" circumstances neither the production rate in the oil sands nor refining activities in the Gulf Coast would change substantially based on whether Keystone XL, as then proposed, was built.

[5] Ensys 2010 WORLD Model results indicated that under the range of "business as usual" pipeline scenarios considered, demand for WCSB in the Gulf Coast would reach 600,000–1,800,000 bpd by 2030 depending primarily on the amount of pipeline capacity built to the west coast of Canada. Business as usual is used in this context to mean a situation in which the industry and market react based on normal commercial incentives.

The production rate in the oil sands was only substantially reduced in scenarios that assumed all pipeline transport capacity was frozen at 2010 levels through 2030. The scenario also assumed that incremental non-pipeline transport capacity (such as rail or tanker) was not available. The EnSys 2010 report concluded that the "No Expansion" scenario had a low probability of occurring.

To better assess the "No Expansion" scenario analyzed by EnSys in 2010, the Department and the USDOE commissioned EnSys to further examine the likelihood of the No Expansion scenario, including assessing in greater detail the potential of non-pipeline transportation of crude oil. In the 2011 No Expansion Update Report, EnSys concluded that even if there were no new pipelines added beyond those existing in 2010, rail supported by barge and tanker, as well as expansions to refining/upgrading in Canada, could accommodate projected oil sands production. In other words, irrespective of whether pipeline capacity were frozen at 2010 levels, EnSys did not find it likely that oil sands production would be reduced, or "shut-in":

- "Broadly, under a Total No Expansion scenario, we see rail supported by barge, tanker and direct upgrading to product as able to deliver sufficient capacity to avert any WCSB shut-in through—and potentially beyond—2030" (EnSys 2011).
- "[W]e believe there is scope across rail and marine options to provide alternatives that, inter alia, could reach and exceed the scale of the Keystone XL pipeline such that neither WCSB nor domestic U.S. production would be shut-in, other than possibly for short periods as is happening today" (EnSys 2011).
- "[W]e do not see cost deterring rail, barge and tanker expansion in any form of "No Expansion" situation" (EnSys 2011).

In addition to its focus on non-pipeline transport modes, the 2011 No Expansion Update Report also examined the potential for modifications to already existing pipeline infrastructure to provide additional capacity and concluded that the potential was substantial. For both non-pipeline expansions and modifications to existing pipelines, EnSys concluded that permitting would likely be easier and development times shorter than for major new pipeline projects.

While the 2011 Final EIS assessment of the potential market impacts of granting or denying a permit for the Keystone XL pipeline was informed by the EnSys studies, it also took account of several other sources of information. In addition to the work by EnSys, which relied in part on inputs from the AEO by the EIA, the Department also examined other sources in preparing the 2011 Final EIS, including: input from experts at the USDOE; information from industry associations (CAPP—Canadian Association of Petroleum Producers), and private consulting companies such as Purvin & Gertz, IHS Cambridge Energy Research Associates, Hart Energy, and ICF International, as well as the numerous comments received from the public.

Taking account of all of the relevant information, the 2011 Final EIS concluded that the proposed Project is unlikely to significantly affect the rate of extraction in the oil sands or in U.S. refining activities. The Final EIS nonetheless, as a matter of policy, included information about the environmental impacts associated with extraction of crude oil in the oil sands, particularly an extensive analysis of the fact that on a life-cycle basis, transportation fuels produced from oil sands crudes emit more greenhouse gases than most conventional crude oils.[6]

[6] This information and analysis is updated in this Supplemental EIS in Section 4.15, Cumulative Effects Assessment.

1.4.4 Market Developments Since the 2011 Final EIS

The analysis presented in this Supplemental EIS uses the most current information available. It examines several recent market outlooks, including the 2013 early release version of the AEO (the 2010 AEO had provided key input assumptions for the EnSys 2010 and 2011 assessments). As in 2011, the Department again consulted with experts from USDOE, and reviewed information from industry associations such as CAPP and private consulting companies such as Ensys, Hart Energy, and ICF International.

The Department also relied on a January 2013 memorandum from the Administrator of the EIA that analyzed some of the key issues also presented in this section (2013 EIA Memo[7]). Finally, the Department also reviewed numerous comments received from the public during the National Interest Determination comment period for the previously proposed Project, and the scoping process for this Supplemental EIS.

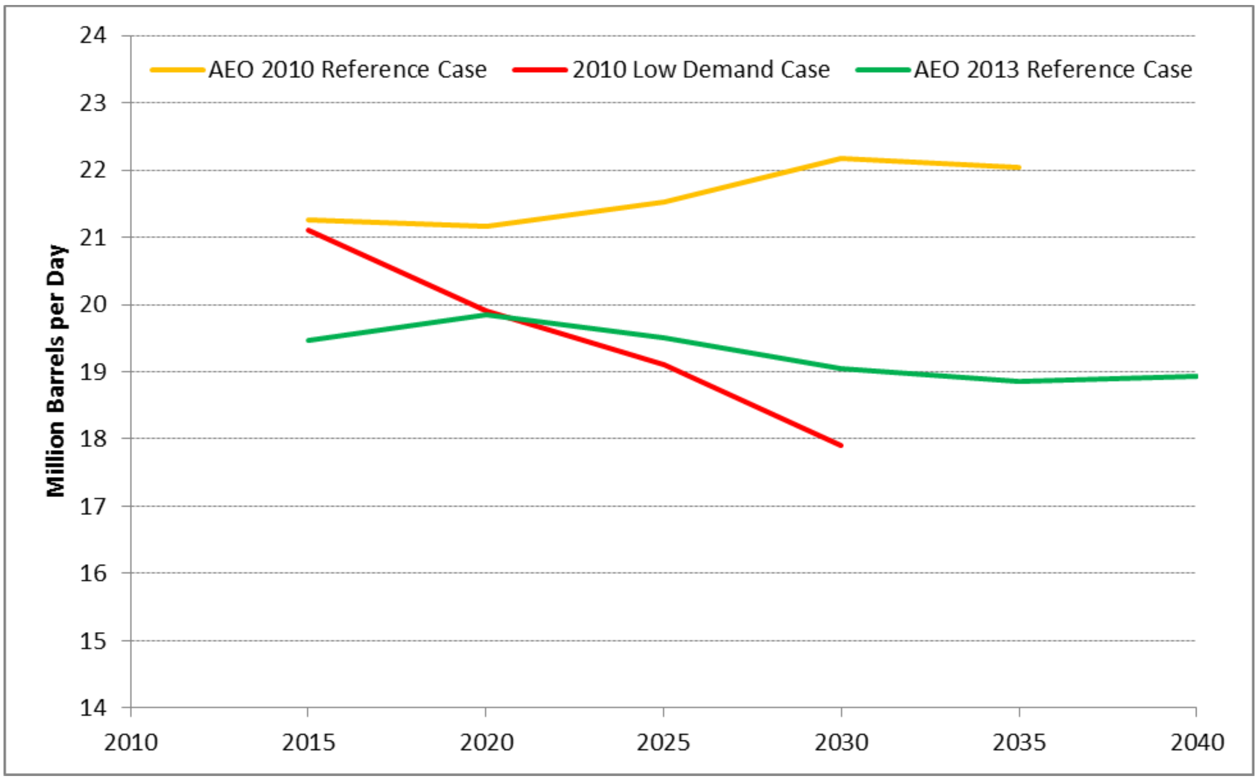
The subsections below examine significant changes to petroleum markets in North America and the potential impacts of these changes on a permitting decision for the proposed Project. Since the 2011 Final EIS and the 2010 and 2011 EnSys Assessments, there have been several developments in the crude oil market in the United States. Among the most significant developments are:

- Continued lower actual and projected demand for gasoline in the United States.
- Developing trends in increased domestic light crude oil production from shale oil formations that emerged in 2010 and 2011 resulting, among other things, in decreasing crude oil imports.
- Developments in the North American crude transport network, including new crude pipeline expansions and increasing use of rail transportation for crude oil.

[7] Included in Appendix C, Market Analysis Supplemental Information, of this Supplemental EIS.

1.4.4.1 Reduction in U.S. Demand

One of the most significant differences in the petroleum market since publication of the 2011 Final EIS is the lower actual and projected demand for liquid fuels[8] in the United States. While the AEO 2013 outlook for liquids demand is lower than the two demand outlooks assessed by EnSys through approximately 2020, it falls between them after 2020 (Figure 1.4.4-1). The majority of this decreased demand outlook comes from lowered projections of demand for gasoline. AEO 2013 has an outlook for gasoline demand that reflects the tightened Corporate Average Fuel Economy standards put in place in 2012 that require an industry-wide standard of 54.5 miles per gallon by 2025. The AEO also incorporates other factors that reduce demand for refinery production of gasoline, namely, a downward trend in per capita miles driven consistent with an ageing population, and increasing use of biofuels, based on renewable fuels mandates (Yglesias 2012).

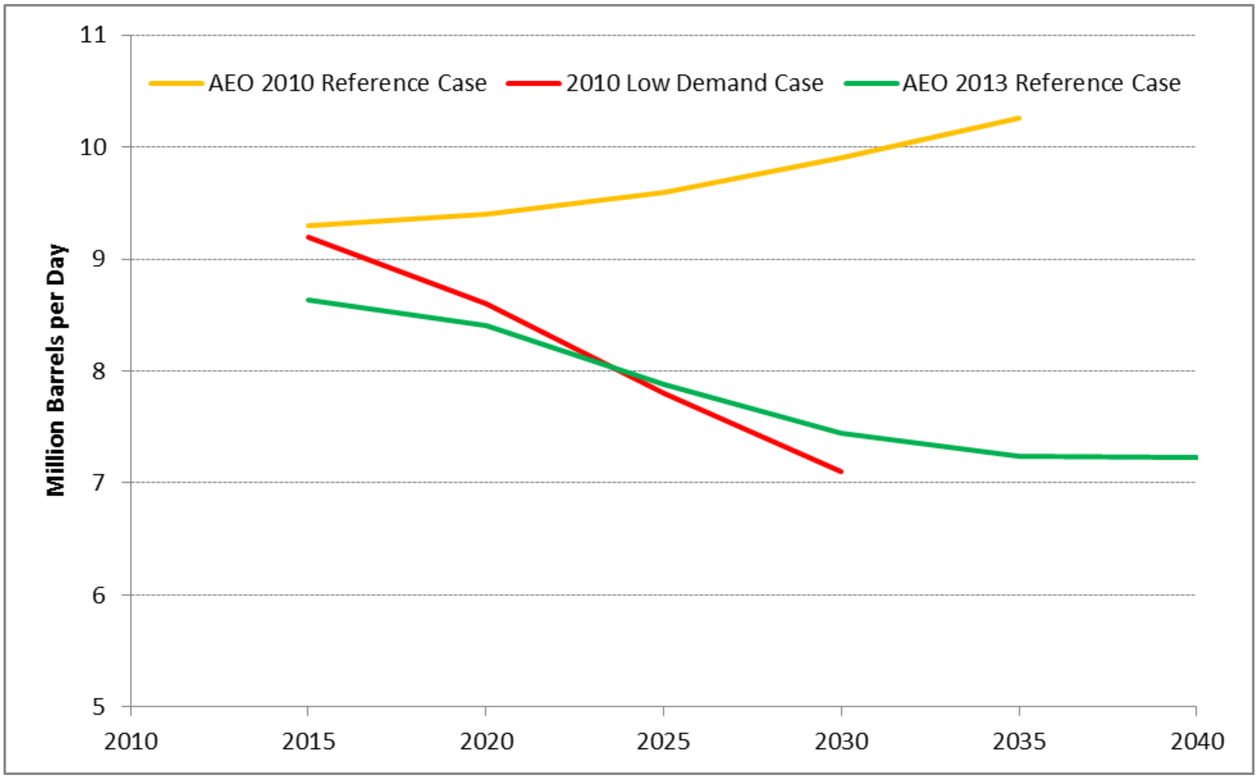


Source: EIA 2010, EnSys 2010, EIA 2013b.

Figure 1.4.4-1 U.S. Product Demand—Total Liquids

[8] Liquid fuels include refined petroleum products, other hydrocarbon fuels, and biofuels. The Total Liquids category in the AEO reports also includes petrochemical feedstocks (such as natural gas liquids).

Compared to the 2010 AEO outlook, the AEO 2013 outlook for gasoline demand is lower. The reduced demand for gasoline in AEO 2013, however, is higher than the gasoline demand in the Low Demand Outlook assessed by EnSys after approximately 2024. According to the AEO 2013, total U.S. product demand in 2030 will be 19.0 million barrels per day (mmbpd), as opposed to 22.2 mmbpd forecast in AEO 2010. By comparison, the Low Demand Outlook assessed by EnSys in 2010 had U.S. total demand dropping to 17.9 mmbpd by 2030 (Figure 1.4.4-1 above).[9] Therefore, the AEO 2013 outlook for gasoline demand falls between the two outlooks assessed by EnSys after 2024 (Figure 1.4.4-2).

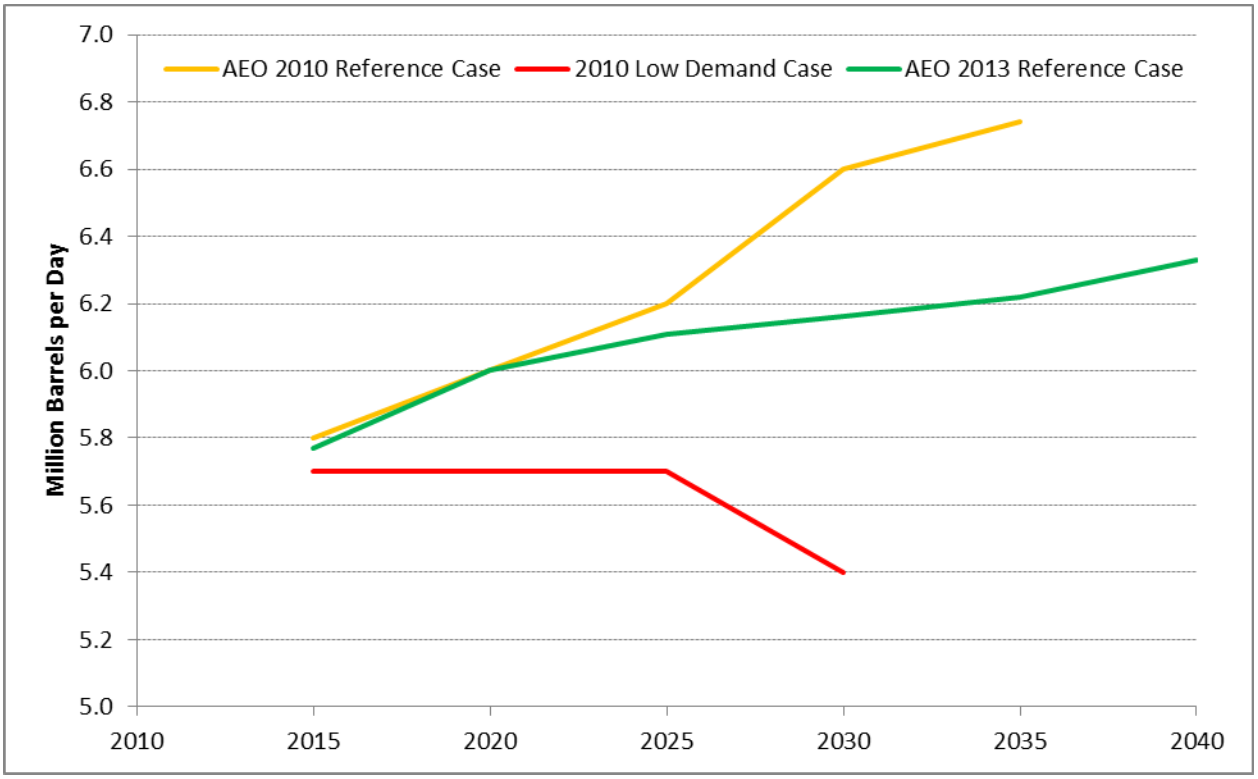


Source: EIA 2010, EnSys 2010, EIA 2013b.

Figure 1.4.4-2 U.S. Product Demand—Gasoline/E85[10]

[9] A table of the complete comparison of the demand outlooks in the AEO 2013, AEO 2010, and the EnSys Low Demand outlook is included in Section 1.2 of Appendix C to this Supplemental EIS.
[10] E85 contains 85 percent ethanol and 15 percent gasoline and is most commonly used in flex-fuel vehicles.

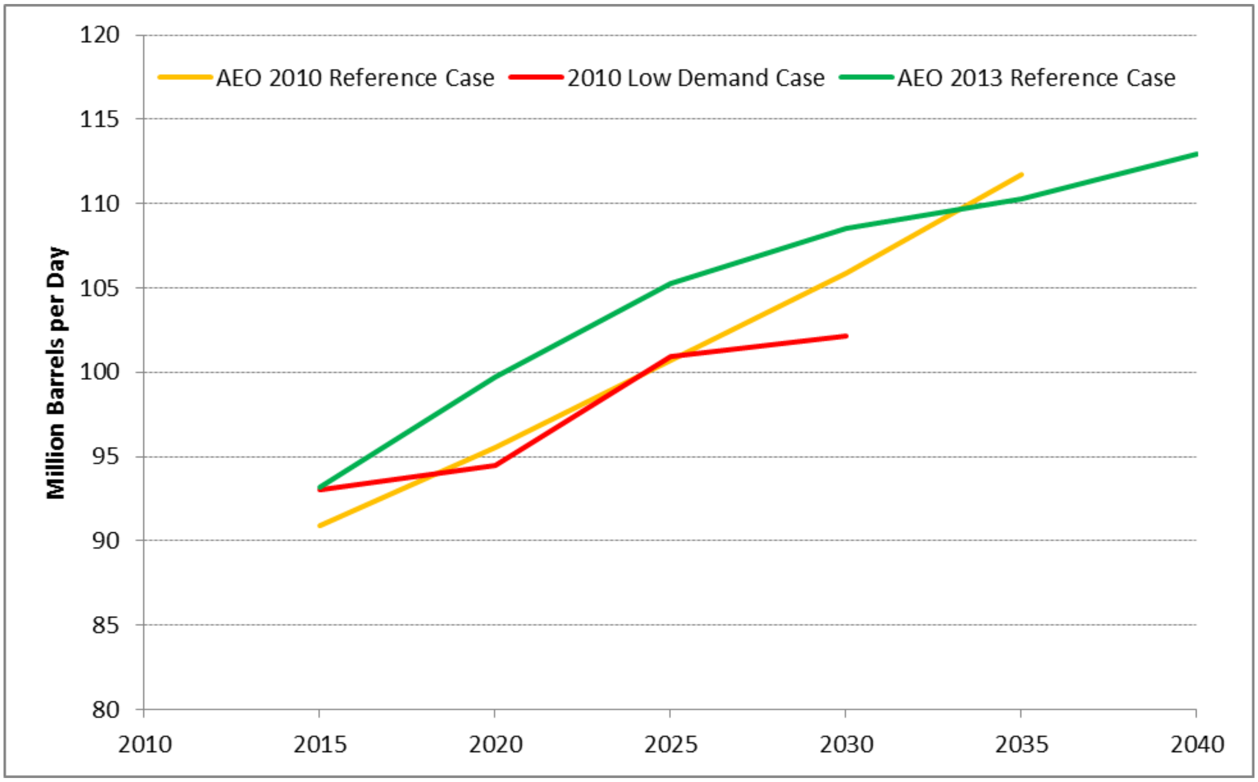
Demand for other liquid products, such as jet fuel and distillates (including diesel), is similar between all three outlooks in the period preceding 2020; however, between the years 2020 and 2030, the 2010 AEO and the 2013 AEO outlooks diverge. Despite the divergence, it is noteworthy that the 2013 AEO outlook projects demand between the two outlooks used as inputs for the 2010 EnSys assessment, namely the 2010 AEO outlook and the Low Demand Outlook (Figure 1.4.4-3). In other words, the EnSys 2010 AEO and Low Demand Outlooks “bracketed” the new AEO 2013 demand outlook for the United States.



Source: EIA 2010, EnSys 2010, EIA 2013b.

Figure 1.4.4-3 U.S. Product Demand—Jet/Distillate

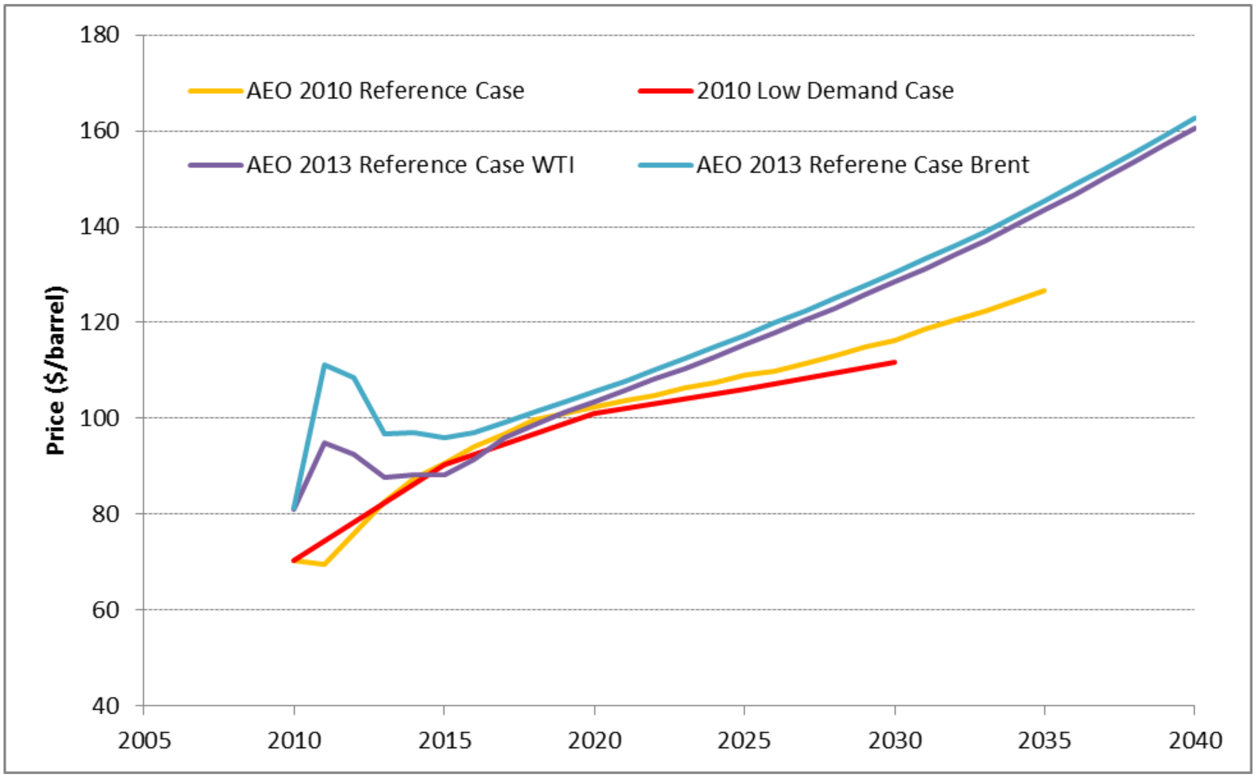
In contrast, the AEO 2013 outlook projects world liquids demand in 2020 and 2030 higher than either of the outlooks (whether the Low Demand Outlook or the 2010 AEO outlook) used by EnSys in its 2010 assessment (Figure 1.4.4-4). The increase in global demand projected by the AEO 2013 outlook is driven by assumptions regarding population and economic growth, particularly growth in non-Organization for Economic Co-operation and Development economies.



Source: EIA 2010, EnSys 2010, EIA 2013b.

Figure 1.4.4-4 Global Liquids Demand

Finally, the Low Demand Outlook used by EnSys in its 2010 assessment projected reduced world oil prices compared to the AEO 2010 outlook. However, the AEO 2013 outlook's projection is for crude oil prices higher than those in either of the outlooks used by EnSys in its 2010 assessment (Figure 1.4.4-5).[11]

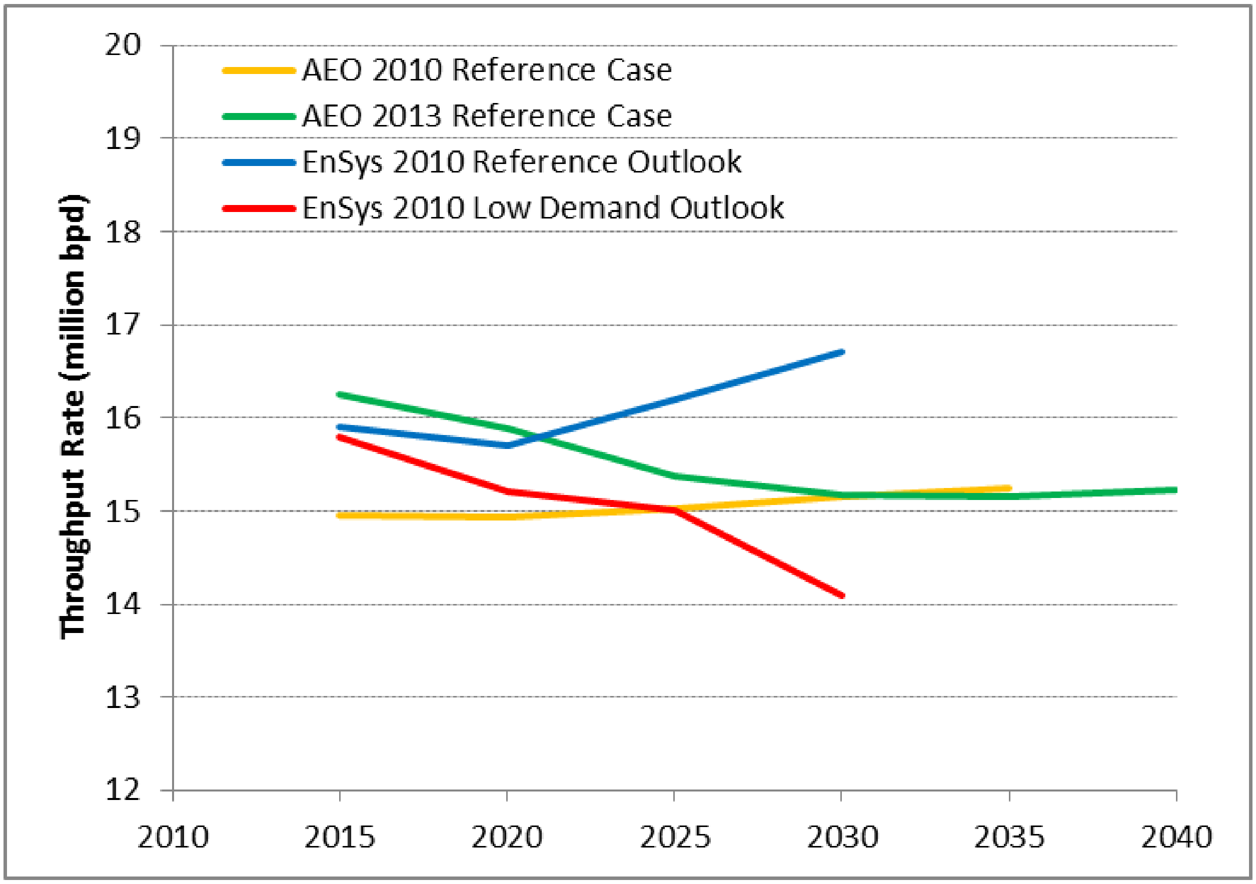


Source: EIA 2010, EnSys 2010, EIA 2013b.

Figure 1.4.4-5 AEO Crude Prices (2011 Dollars)

[11] The AEO 2013 switched its outlooks for crude oil prices to include West Texas Intermediate (WTI) and Brent (a global, light crude benchmark). This change was made to account for the fact that WTI prices have become decoupled from global crude prices because of transportation constraints. This is explained further in Appendix C, Market Analysis Supplemental Information.

While the AEO 2013 estimates a reduced demand outlook for the United States, it also projects increases in U.S. refined product exports and thus U.S. refinery throughput rates similar to those in the AEO 2010, especially longer term (Figure 1.4.4-6). Further, the AEO 2013 supply outlook for renewable liquid fuels (biofuels) is also projected to be substantially lower than the AEO 2010 outlook.



Source: EIA 2010, EnSys 2010, EIA 2013b.

Note: The EnSys 2010 Reference outlook is based on the 2010 EIA AEO reference case, but has independent projections of refinery throughput. The Low Demand Outlook scenario was based on USDOE's Energy Perspectives Model as applied by Brookhaven National Laboratory. This model was based on a USEPA study that assumed more aggressive fuel economy standards and policies to address miles traveled.

Figure 1.4.4-6 Domestic Refinery Throughput

The EnSys 2010 WORLD Model results indicated that, regardless of the input used, whether the Low Demand Outlook or the AEO 2010 outlook, the proposed Project would not affect extraction in the oil sands or refining activities on the U.S. Gulf Coast. Neither outlook materially altered the demand for heavy sour crude by refineries on the Gulf Coast or the total U.S. imports of Canadian crude.[12] In other words, demand for heavy sour Canadian crudes at U.S. refineries, including on the Gulf Coast, was projected to be relatively insensitive to the level of U.S. product demand decrease.

Thus, under the AEO 2013 outlook, U.S. product demand is lower than under the 2010 AEO Reference case (although higher than that projected under the more conservative Low Demand Outlook studied by EnSys in 2010). The outlook is now for higher U.S. exports of refined products. These are acting to offset the lower domestic demand and raise U.S. refinery throughputs back to levels similar to those projected under the AEO 2010 outlook (Figure 1.4.4-6). U.S. refineries have not materially changed over the last two to three years; indeed, the major projects that have gone ahead both in PADD 2 and on the Gulf Coast (PADD 3) have been geared to increasing heavy crudes processing. Having made significant investments in equipment to process heavy sour crude, refiners have strong incentive to obtain such crudes (Section 1.4.4.3, Increase in United States Crude Production). The combined effect of these demand, export, and refining factors is that, although the demand outlook has changed, the refining outlook is similar.

1.4.4.2 Refined Product and Crude Oil Exports

It is likely that increasing amounts of WCSB crudes will reach Gulf Coast refiners whether or not the proposed Project goes forward (products from this processing will be used in both domestic markets and for export). As a result, future refined product export trends are also unlikely to be significantly impacted by the proposed Project. Gulf Coast refiners typically seek to obtain crude oil under long-term supply contracts from reliable sources that can provide crude oil types that match their refining configurations. This is the case for heavy WCSB crudes, which match well with the large amount of heavy crude processing capacity on the Gulf Coast. Therefore, existing refinery throughputs and product exports are likely to continue, with attendant impacts. As detailed in Section 1.4.6, Crude Oil Transportation, non-pipeline transport options, particularly rail, are being used to transport WCSB crude oil, and thus the proposed Project is unlikely to significantly affect U.S. refining activities.

Projections for petroleum product import and export volumes have undergone substantive changes between the 2010 and more recent AEO reports. Table 1.4-1 compares 2010 and 2012 AEO U.S. import and export volumes. The table indicates that the 2012 AEO expects petroleum product imports and exports to essentially offset each other through 2020 (i.e., "net" zero petroleum imports), whereas the 2010 AEO anticipated a steady need for almost 2.9 mmbpd of gross product imports and a net import requirement of roughly 1.1–1.3 mmbpd over the period. This significant change is driven primarily by the lower U.S. demand forecasts shown in the figures above.

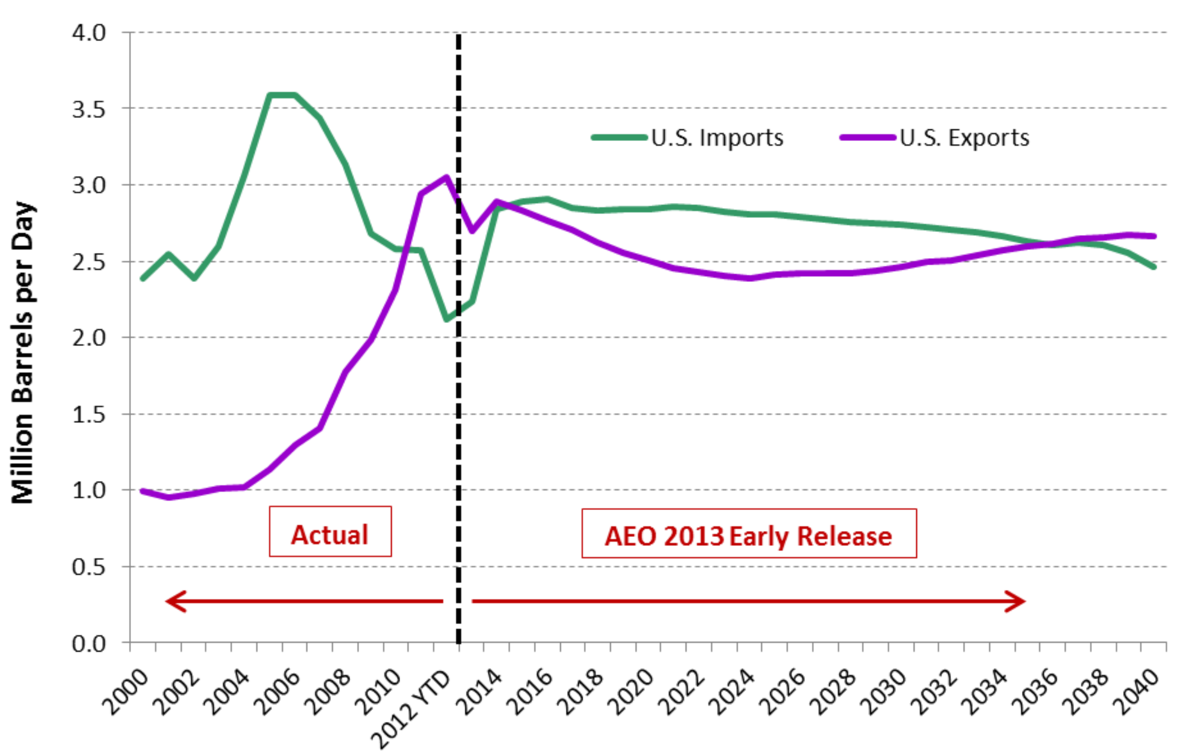
[12] Among the differences between the AEO 2010 outlook results as compared with the Low Demand Outlook results in EnSys 2010, were that in the Low Demand Outlook there were lower refinery throughputs and increases in net refined product exports from the United States.

Table 1.4-1 Comparison of 2010 and 2012 AEO U.S. Product Import and Export Volumes

	Imports (mmbpd)			Exports (mmbpd)		
	2012	2015	2020	2012	2015	2020
2010 AEO	2.892	2.844	2.873	1.596	1.655	1.745
2012 AEO	2.462	2.218	2.063	2.466	2.341	2.050
Change	(0.429)	(0.626)	(0.810)	0.870	0.687	0.305

Source: EIA 2010, EIA 2012c.

Exports of petroleum products averaged around 1 mmbpd throughout the 1990s up to 2005. In 2005, exports began increasing. Exports were typically either products not consumed in large quantities in the United States (petroleum coke, residual fuel, etc.) or gasoline and distillate oils (such as diesel and heating oils). Export volumes have increased to over 3 mmbpd in the first half of 2012. This increased volume of refined products is being exported by refiners as they respond to lower domestic gasoline demand and continued higher demand and prices in overseas markets (Figure 1.4.4-7). Most of these exports are from PADD 3. However, almost half of PADD 3 refined products go to the domestic market.[13]



Source: EIA 2012d.

Figure 1.4.4-7 U.S. Total Product Import and Export Trends, 2000-2012 YTD, mmbpd

[13] In 2011, 1.6 mmbpd of finished petroleum products were supplied to the U.S. market out of a total of 3.5 mmbpd produced in PADD 3 (EIA 2011).

In addition to the concerns expressed about exports of refined products, there is a question of whether the oil sands/Western Canadian Select (WCS) crude oil transported into Gulf Coast markets via the proposed Project may be simply "passed through" the market and loaded onto vessels for ultimate sale in markets such as Asia or Europe. Under the current market outlooks, such an option is unlikely to be economically justified primarily due to transportation costs. Once the WCSB crude oil arrives at the Gulf Coast, the refiners there have a significant competitive advantage in processing it compared to foreign refiners because the foreign refiners would have to incur additional transportation charges to have the crude oil delivered from the Gulf Coast to their location.

Gulf Coast refiners' traditional sources of heavy crudes, particularly Mexico and Venezuela, are declining and are expected to continue to decline. This results in an outlook where the refiners have significant incentive to obtain heavy crude from the oil sands. Both the EIA's 2013 AEO and the Hart Heavy Oil Outlook (Hart 2012b) indicate that this demand for heavy crude in the Gulf Coast refineries is likely to persist throughout their outlook periods (2040 and 2035 respectively). The EnSys 2010 analysis, discussed in more detail below, projected that, by 2030, U.S. Gulf Coast (PADD 3) refineries could economically absorb and process 1.5 to 2 million bpd of WCSB crudes (predominantly heavy/oil sands streams); less if a large amount of pipeline capacity were built to the British Columbia coast, opening up markets in Asia. Thus Gulf Coast refineries have the potential to absorb volumes of WCSB crude that go well beyond those that would be delivered via the proposed Project. On this basis, the likelihood that WCSB crudes will be exported in volume from the Gulf Coast is considered low.

For example, the transportation costs of shipping to Asia via the Canadian or U.S. West Coasts would be significantly cheaper than trying to export it via the U.S. Gulf Coast.[14] The total per barrel cost of export to Asia via pipeline to the Canadian West Coast and onward on a tanker is less than just the estimated pipeline tariff to the U.S. Gulf Coast for the proposed Project, and is less than half the cost of the Gulf Coast route to Asia. If pipelines to the Canadian West coast are not expanded or approved, even incurring the additional cost of rail transport to the West Coast ports (Vancouver, Kitimat, or Prince Rupert), estimated at $6 per barrel, results in a total transport cost to Asia that is still 40 percent cheaper than going via the Gulf Coast (Table 1.4-2). Absent a complete block on crude oil exports from the Canadian West Coast, there would be little economic incentive to use the proposed project as a pass through. The high costs of onward transport to other potential destinations tend to mitigate against WCSB heavy/oil sands crudes being exported in volume from the Gulf Coast.

Table 1.4-2 Comparison of Transport Costs for Routes to Asian Markets

	Pipeline/Rail cost	Marine Transport (Suezmax)	Marine Transport (VLCC)	Total Transport Cost
Canadian West Coast (via pipeline) to Asia	$4–5	$3	$2	$6–8
Canadian West Coast (via rail) to Asia	$6	$3	$2	$8–9
U.S. Gulf Coast (via pipeline) to Asia	$8–9	$7	$5	$13–16

Source: Poten and Partners 2013.

[14] The estimated landed cost for heavy crudes (Arab Heavy or Indonesian Duri) in Northeast Asian markets would be approximately $100–$110 per barrel. Western Canadian Select could be expected to have a slight discount from those types of crudes.

It is possible that Canadian-origin crude oil transported to the Gulf Coast area (whether by the proposed Project, other pipelines, or by rail) could be exported to other countries. There is a restriction on exporting domestically produced crude oils. Export licenses can be obtained for a foreign-origin crude provided it has not been commingled with crude oil of U.S. origin (15 Code of Federal Regulations 754.2(b)(vii)). To export a foreign-origin crude, the exporter must demonstrate to the Department of Commerce Bureau of Industry and Security that the crude oil in question is not of U.S. origin and has not been commingled with oil of U.S. origin.

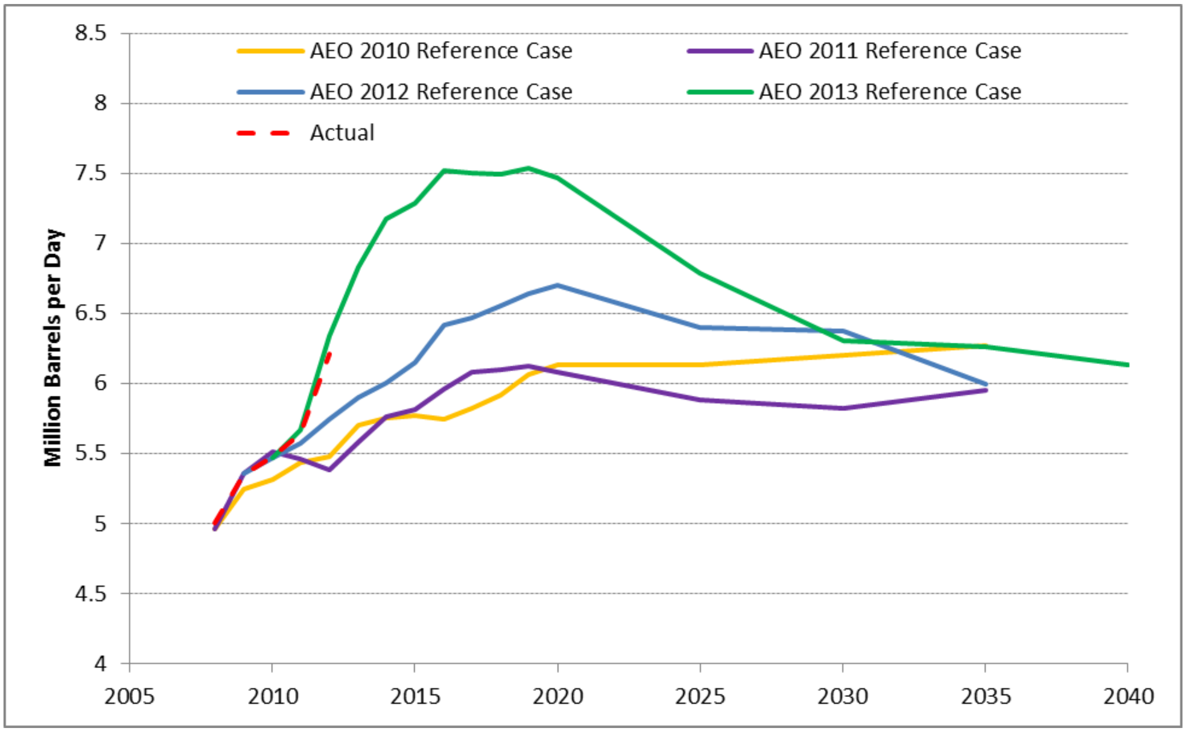
1.4.4.3 Increase in United States Crude Oil Production

The 2011 Final EIS was developed contemporaneously with the beginnings of strong growth in domestic light crude oil supply from so-called “tight” oil formations. Light crude oil that is extracted from shale formations is generally referred to as tight oil.[15] Since 2010, domestic production of crude oil has increased significantly, up from approximately 5.5 mmbpd to over 6.5 mmbpd. In addition to contributing to significant discounts on the price of inland crude because of logistics constraints, (discussed below and in Appendix C, Market Analysis Supplemental Information), there has been a sharp reduction in U.S. imports of crude oil, in particular reductions in imports of light-sweet crude oil. The outlook in AEO 2013 is for higher domestic production of light crude oil compared to AEO 2010.

This latest AEO projects a surge in U.S. crude oil production over the next 10 years driven by the shale/tight oil production increases; however, the projection is also for this surge to peak around 2020 and thereafter for U.S. production to decline such that the AEO 2010 and 2013 outlooks are very similar from 2030 onward (Figure 1.4.4-8).[16] Additionally, a study by the International Energy Agency (IEA) World Energy Outlook (WEO) 2012 has a higher outlook for U.S tight oil production, 3.2 million bpd, but shows a similar bulge trend.

[15] The major U.S. tight oil sources include the Bakken in the Williston Basin of North Dakota and Montana; the Eagle Ford in South Texas; the Mississippian Lime in Oklahoma and Kansas; the Tuscaloosa Marine Shale in Louisiana; the Monterey and Kreyenhagen in California; the Avalon, Bone Springs, and Wolfberry in the Permian Basin of Texas and New Mexico; the Niobrara in Colorado and Wyoming; and the Utica shale in Ohio and Pennsylvania.

[16] The EIA’s Short Term Energy Outlook from January 2013 estimated U.S. crude production in 2013 and 2014 to be approximately 500,000 bpd more than the AEO 2013 early release. The IEA WEO 2012 has a higher outlook for U.S tight oil production, 3.2 mmbpd, but shows a similar bulge trend.



Source: EIA 2010, EIA 2011, EIA 2012c, EIA 2013.

Figure 1.4.4-8 Comparison of AEO Forecasts for Domestic Crude and Condensate Production

A substantial portion of this reduction in imports has occurred in PADD 3. As discussed above and in Section 1.3, Purpose and Need, PADD 3 is the major refining center of the United States and would be the ultimate delivery location of most of the crude oil that would be transported by the proposed Project if approved. The 2011 Final EIS market analysis cited 2009 crude import levels and total crude imports.

Based on EIA import data, total crude imports into PADD 3 were 5.029 mmbpd in 2009, compared to 4.620 mmbpd in 2012 (June year-to-date), as shown in Table 1.4-3.

Table 1.4-3 Comparison of PADD 3 Crude Oil Imports and Sources, 2009 vs. 2012 Year to Date[a]

Country	2009 (mmbpd)	2012 (mmbpd)	2009 (%)	2012 (%)
Mexico	1.089	0.936	22%	20%
Venezuela	0.842	0.774	17%	17%
Saudi Arabia	0.620	1.028	12%	22%
Nigeria	0.571	0.260	11%	6%
Other Countries (>5%)	0.260	0.889	5%	19%
Other Countries (<=5%)	1.646	0.733	33%	16%
Total	**5.029**	**4.620**	**100%**	**100%**

Source: EIA 2009, EIA 2012e.

[a] The "Other Countries" category percentages reflect percent of total imports into PADD 3. Other countries >5 percent include Iraq in 2009 and Colombia, Kuwait, and Iraq in 2012.

Light crude oil imports (crude oil over 35 API gravity)[17] were reduced by about a third, from 1.042 mmbpd to 0.690 mmbpd. Large reductions occurred in both Nigerian and Algerian imports of light crude oil, as well as from the United Kingdom and Venezuela, offset by higher Saudi light imports as well as more Mexican light crude (often used for lube production). Heavy crude imports (crude oil under 25 API) were nearly unchanged over this period (Table 1.4-4). Significant reductions in Mexican heavy crude oil were offset by increases from Brazil, Colombia, and Venezuela.

Table 1.4-4 Heavy Crude Import Trends in PADD 3, 2009 and 2012 (through June 2012), mmbpd

Country	2009 (mmbpd)	2012 (mmbpd)
Mexico	0.944	0.711
Venezuela	0.704	0.748
Brazil	0.117	0.190
Colombia	0.159	0.240
Canada	0.096	0.097
Others	0.214	0.173
Total	**2.234**	**2.160**

Source: EIA 2009, EIA 2012e.

[17] API gravity is the American Petroleum Institute's scale for expressing the gravity or density of crude oil (among other liquids). Water has an API gravity of 10. There is a range of cutoff points that are used to specify heavy crude oil. Generally, an API gravity of around 28 is considered the cutoff for the lightest heavy crude that is suited to processing in a "deep conversion" refinery, one that usually in the U.S. has a coker to upgrade the heaviest residuum fractions to light products. Nonetheless, a common cutoff is 25 API and that is what is used in this analysis. For comparison, Brent crude has an API gravity of about 38 and WTI has an API gravity of around 40.

Table 1.4-5 shows heavy crude imports (crude oil under 25 API gravity) in 2012 for Gulf Coast area refiners who are in the anticipated destination market for most of the proposed Project's heavy crude oil shipments. This table indicates that there are about 1.6 mmbpd of heavy crude imports into refiners along the Gulf Coast area through Lake Charles, Louisiana, and that 12 refineries alone processed almost 1.5 mmbpd of heavy crude in the first half of 2012.

Table 1.4-5 Gulf Coast Area Refiners Heavy Crude Processing, January–June 2012[a]

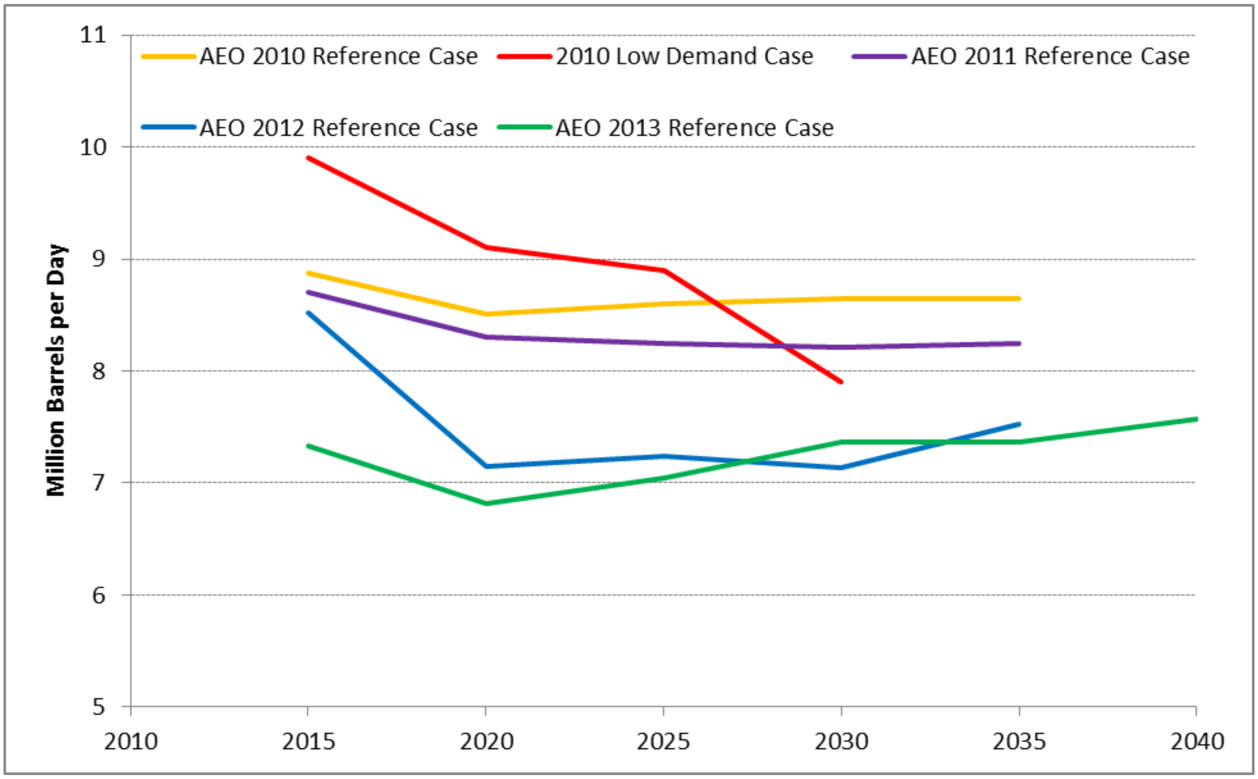
Refiner	Refinery Capacity (bpd)[b]	Heavy Crude Imports	Number of Refineries	Top 2 Import Sources of Heavy Crude
Valero Refining Co Texas LP	803,000	328,077	4	Mexico, Venezuela
CITGO Petroleum Corp	590,800	268,692	2	Venezuela, Mexico
ConocoPhillips Company	486,400	260,038	2	Venezuela, Mexico
Houston Refining LP	273,433	247,467	1	Venezuela, Colombia
Deer Park Refining LTD Partnership	327,000	198,297	1	Mexico, Colombia
ExxonMobil Refining & Supply Co	905,000	184,544	2	Mexico, Brazil
Total Petrochemicals Inc.	130,000	74,269	1	Brazil, Colombia
BP Products North America Inc.	400,780	36,709	1	Kuwait, Mexico
Flint Hills Resources LP	284,172	12,154	1	Brazil, Venezuela
Motiva Enterprises LLC[c]	285,000	2,742	1	Colombia
Total	**4,485,585**	**1,612,989**	**16**	

Source: EIA 2012d, EIA 2012e.

[a] The Gulf Coast area refers to the region from Houston, Texas, to Lake Charles, Louisiana.
[b] These figures are nameplate capacities for refineries. Actual production will vary over the year based on availability of feedstock and maintenance. The average monthly operable utilization rate from January through November 2012 for PADD 3 refineries was 89.3 percent.
[c] The Motiva Port Arthur refinery commissioned a major expansion to 600,000 bpd in early 2012. However, the refinery suffered a fire in the new crude unit and that unit was restarted in early 2013.

As discussed in the introduction to this sub-section above, the projections for production from domestic tight oil supply indicate an increase until 2020 to 2025 and then begin to decline. The 2013 AEO outlook has domestic crude oil production approximately 1.5 mmbpd higher than the 2010 AEO outlook from now until 2020 (Figure 1.4.4-8). However, the outlook suggests that after 2020, U.S. production will begin to decline. By 2025 domestic crude oil production is anticipated to be only approximately 600,000 bpd higher than the 2010 outlook. After 2025 the 2010 AEO and the 2013 AEO are essentially the same. As explained further below, the increase in domestic production of light crude is expected to result in a substantial reduction in imports of light crude oils rather than a reduction in demand for heavy, sour crude oils, including from Canada.

The combination of lower U.S. demand and increased U.S. production as assessed in the 2013 AEO has significantly reduced the outlook for total U.S. crude oil imports compared to the 2010 AEO. Similarly, compared to the EnSys Low Demand Outlook, the 2013 outlook has lower net crude oil imports until 2030, at which time the amounts are nearly equal in the two outlooks. Nevertheless, the United States is expected to remain a significant importer of crude oil throughout the AEO 2013 outlook period (to 2040), importing between approximately 7 and 7.5 mmbpd throughout the period (Figure 1.4.4-9).



Source: EIA 2010; EnSys 2010; EIA 2011; EIA 2012c; EIA 2013.

Figure 1.4.4-9 U.S. Net Crude Imports

The AEO outlooks, as well as the current trends in the market, suggest that increased production of tight oil (light, sweet grade of crude oil), has not impacted the demand for heavy, sour crude oil at the U.S. refineries optimized to process heavy crude oil. The EIA notes, "AEO2013, AEO2012, and AEO2011 all project continued strong demand for heavy sour crudes from Gulf Coast refiners that are optimized to process such oil" (see the 2013 EIA memo in Appendix C, Market Analysis Supplemental Information). A main driver for this is that although refiners' can be expected to make adjustments in their operations to take advantage of the increased supply of light crudes on the markets, shutting down their heavy crude upgrading units would likely be the most inefficient and expensive option.[18] The 2013 EIA memorandum specifically addresses the period leading up to 2025 because that is around the time the U.S. domestic production of tight oil is expected to peak and have its most significant potential impact on the market.[19]

The trend in flattening domestic production of tight oil after 2025 in the AEO 2013 indicates that the long-term domestic production outlook is also unlikely to significantly impact demand for heavy sour crudes at Gulf Coast refiners. The Hart Energy Heavy Oil Outlook projects demand for heavy sour crude continuing in the long-term at U.S. refineries in the Midwest and Gulf Coast (Table 1.4-6).[20]

Table 1.4-6 U.S. Heavy and Canadian Heavy Crude Oil Refined

Heavy Crude Refined (mmbpd)						
	2011	**2015**	**2020**	**2025**	**2030**	**2035**
Total U.S. Heavy Crude Refined	2,611	3,134	3,987	4,030	4,022	4,183
Canadian Heavy Crude Refined in United States	1,242	1,769	3,277	3,535	3,690	3,900

Source: Hart 2012b.

The EIA noted, "While the AEO does not identify specific supply sources for imported crude used by U.S. refiners, Canada is certainly a likely source for heavy grades" (2013 EIA Memo, included in Appendix C, Market Analysis Supplemental Information). As a result of broader heavy crude production and export trends in the world that may result in a declining supply of heavy crude oil on the export market, the Gulf Coast refiners are likely to have significant incentive to meet their demand for heavy sour crude by obtaining WCSB crudes.

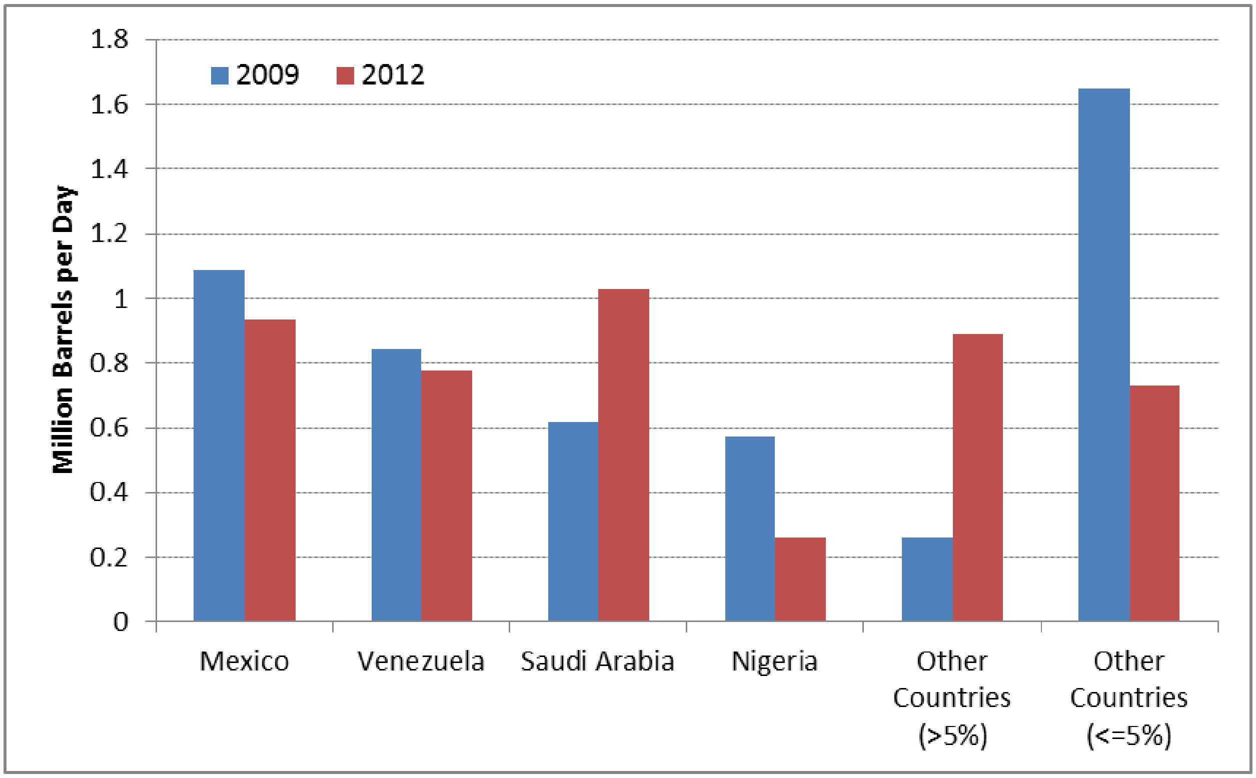
The EnSys 2010 report stated, "[D]evelopments create an outlook where PADD 3 refiners could have difficulty in the future competing for and obtaining sufficient heavy crudes to fill available heavy crude processing and upgrading capacity, and therefore a priori could be expected to have an interest in acquiring heavy WCSB crudes." EnSys arrived at this conclusion in part because of the declining production from the traditional suppliers of heavy sour crude oils to PADD 3, Mexico and Venezuela (Figure 1.4.4-10). Production from both has been in decline in recent years. Mexican production of heavy sour crude is expected to continue to decline. Venezuelan production has more potential to increase in the long-term, but political uncertainty may make it less available to U.S. refiners. EnSys 2010 also noted a trend in countries that produce heavy

[18] With the significant increase in rail facilities being constructed on the East Coast (see Section 1.4.6.2, Increases in Rail Capacity, below), it appears that significant amounts of inland light crude will be sent there as well as to the Gulf Coast. Commentators suggest the trend will be in continued reductions in crude oil imports in both PADDs.

[19] Some commentators have speculated that the increased supply of light tight oil from formations such as the Bakken could further drive down inland crude oil prices in North America and make some of the most expensive oil sands projects uneconomic (Kemp 2012; Vanderklippe 2012). Again, because the light tight oil wells are relatively new, there is limited data on their long-term productivity and as such, the long-term projections underlying those commenters' views should be understood within that context. Also, light tight oil is also a relatively expensive source of crude oil, falling somewhere in the mid-range of oil sands projects (discussed further in Section 1.4.6, Crude Oil Transportation), so the increased production of light tight oil is also sensitive to lower oil prices.

[20] Compared to previous Hart outlooks, the 2012 outlook had lower total heavy crude imports to the United States because the outlook assumed U.S. refineries would respond to the increased supply of domestic light crude by not adding any additional upgrading capacity for heavy crude beyond that already under construction before 2030. In the 2010 EnSys study relied on in the 2011 Final EIS, EnSys assumed there would be no new upgrades at U.S. refineries to process heavy crude beyond projects then-announced and under construction until after 2025.

crude oil toward upgrading or expanding their refining capacity to process more of their heavy crudes domestically, and then to export more of the higher-value light crudes. In other words, appreciable volumes of incremental heavy crude supply (notably from Saudi Arabia, Brazil, and Colombia) would not necessarily reach international crude markets and thus would not be available to PADD 3 refineries. Another study, the Hart Energy's 2012 Heavy Oil Outlook, includes a similar trend in declining supply of heavy crude oil available on the world market for U.S. refineries outside of oil sands heavy crude oil, supporting the EnSys 2010 assessment.[21]



Source: EIA 2009, EIA 2012e.

Note: Other countries >5 percent include Iraq in 2009 and Colombia, Kuwait, and Iraq in 2012.

Figure 1.4.4-10 Comparison of PADD 3 Crude Oil Imports and Sources

[21] The above information is consistent with the recent WEO produced by the IEA, an autonomous agency made up of 28 oil importing countries, including the United States, which studies global energy markets. Comparing the reference case for oil sands production in the IEA's 2012 WEO with previous years indicates that neither the large influx of light tight oil nor the significant decrease in U.S. demand significantly impacts the supply or demand outlook for heavy crude oil derived from the oil sands.

1.4.4.4 Increase in Projected Canadian Crude Oil Production

The production of Western Canadian crude oil is anticipated to increase substantially by 2020 based on the CAPP 2012 outlook. The CAPP 2012 outlook anticipates an increase from about 2.6 mmbpd in 2010 to 4.5 mmbpd in 2020. Canada's National Energy Board (NEB), a Canadian governmental agency, issued a report in 2012 that indicates similar projections (NEB 2012). According to information contained in these reports, growth in production will occur primarily from oil sands development as well as from Canadian tight oil development, including at formations in the Cardium, Viking, Lower Shaunavon, Montney/Doig, Lower Ameranth, Pekisko, Bakken/Three Forks, Exshaw, Duvernay/Muskwa, Slave Point, and Beaverhill Lake. Actual production year-to-date in 2012 is about 2.95 mmbpd, slightly under the CAPP 2012 forecast of 3.0 mmbpd, but higher than the 2010 and 2011 CAPP forecasts for 2012. Section 1.4 of Appendix C, Market Analysis Supplemental Information, shows the performance of CAPP forecasts versus actual production from 2006 to 2011.

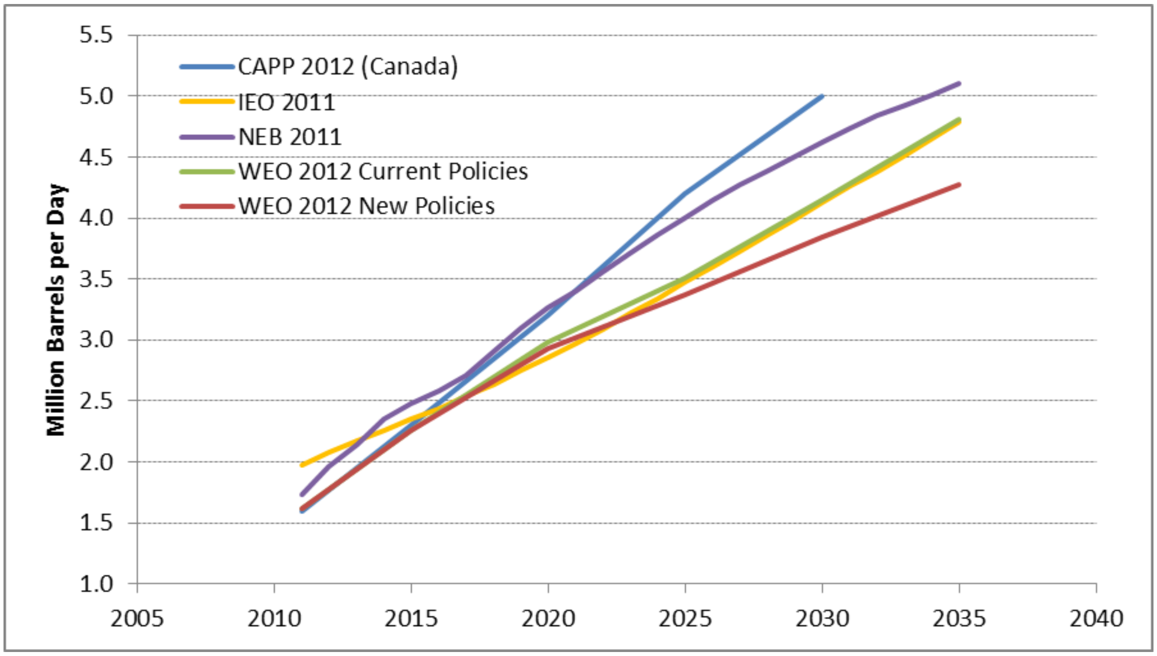
Actual growth rates from 2010 to 2012 are also approximately the rate of growth predicted from 2012 forward. Commitments from shippers on the proposed pipeline projects that connect to the Gulf Coast area (both the proposed Project and the Enbridge projects), together with projected increases in rail transport and known Midwest refinery upgrading projects, support the CAPP forecast for increasing WCSB production over the next 3 to 5 years.[22] The CAPP forecasts are slightly higher for long-term growth than the most recent forecast (from 2011) by the Canadian NEB (6 mmbpd of total Canadian production and 5 mmbpd of production from oil sands by 2035), which examines publicly announced projects but then applies a discounting factor on the likelihood of development based on what stage of production the proposed project was in (NEB 2011, 2012).

Nevertheless, it is noteworthy that both the CAPP and NEB forecasts are higher than the most recent WEO 2012 forecast, which projects an increase in oil sands production to 4.8 mmbpd by 2035 in the Current Policies Scenario and 4.3 mmbpd in the New Policies Scenario (Figure 1.4.4-11).[23] Regardless, all of these projections represent substantial potential growth in the oil sands.

CAPP forecasts over the past 6 years have varied. The actual growth in CAPP crude oil production was affected in 2008–2009 by the global economic recession and has rebounded as economic conditions have improved. The 2012 CAPP forecast represents a "middle of the road" outlook. The CAPP forecasts generally have overestimated potential production compared to the trend of actual production (Figure 1.4.4-12).

[22] U.S. Midwest refinery upgrading projects include BP in Whiting, Indiana; Marathon Oil in Detroit, Michigan; and BP-Husky in Toledo, Ohio.

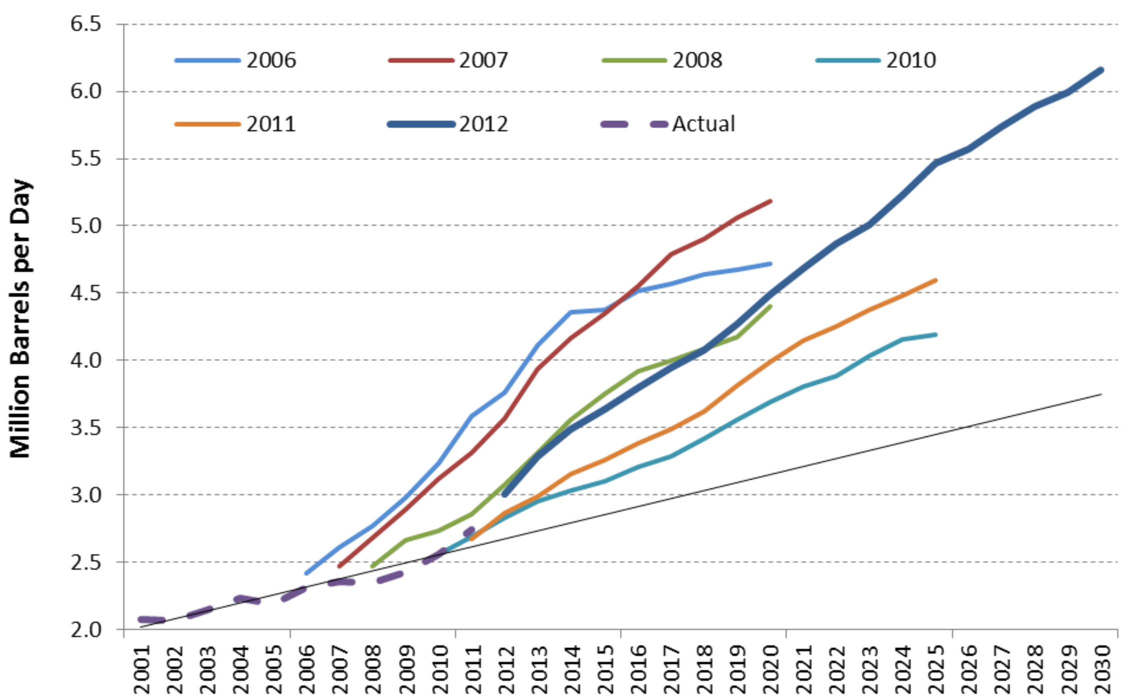
[23] The WEO includes different scenarios regarding policies to address climate change and energy use. The Current Policies Scenario assumes no change from policies currently in effect when the WEO is produced. The New Policies Scenario (which the WEO uses as its reference case) assumes policy commitments regarding climate change mitigation and energy use that countries have made, but not yet implemented, will go forward in a reasonable time. The 450 Scenario assumes policy action consistent with limiting long-term global temperature increase to 2 degrees Celsius.



Source: CAPP 2012, NEB 2011, IEA 2012, EIA 2011b.

Note: NEB 2011 data includes mined and in-situ bitumen production.

Figure 1.4.4-11 Comparison of Canadian Oil Sands Crude Oil Production Forecasts



Source: CAPP 2012; CAPP 2011; CAPP 2010; CAPP 2008; CAPP 2007; CAPP 2006.

Figure 1.4.4-12 Comparison of CAPP Forecasts and Actual Production, 2006 to 2012

The difference in long-term growth projections between the light sweet tight oil versus the WCSB heavy crudes could be expected to impact refiners' decisions regarding their investments. Refiners take long-term growth projections of different types of oils into account when they decide whether to make whatever improvements are necessary to process one grade of crude versus the other. The 2013 AEO early release version projects a relatively rapid increase in U.S. total crude oil production, spurred by shale developments, followed by a peak and decline, such that by the late 2020's the outlook is little changed from that in the 2010 AEO. Thus, this latest EIA projection indicates a relatively short- to medium-term "bulge" in U.S. crude production followed by a return to a downward trend. In contrast, projections from CAPP and others of WCSB production are for a steady, sustained growth over the medium- to long-term, in large part because the bulk of the growth is projected to come from oil sands which do not suffer the same decline profiles as do conventional and especially "tight" crudes.

Since major refinery projects are evaluated based on a presumed 15+/- year life, this distinction between projected supply growth in the United States ("bulge" of light crudes) and in Western Canada (steady growth of heavy crudes) may provide a basis for two types of capital investments: major, long-term expenditure to process heavy WCSB crude supplies, and smaller "revamp" projects with shorter payback periods to process light "tight" crude oils.

1.4.5 Pipeline Capacity out of WCSB

The analysis in the Final EIS, including the 2010 and 2011 EnSys analysis, examined estimates of current pipeline capacity relative to increases in production, and provided an estimated date of when the current capacity would be filled. The EnSys 2010 analysis estimated that existing cross-border pipeline capacity could be filled by shortly after 2020, and the EnSys 2011 update noted that it could likely be filled before 2020 based on increased production projections. Since the 2011 EnSys study, the CAPP production projection has increased from 3.8 mmbpd to 4.7 mmbpd by 2020 (and 6.2 mmbpd by 2030), implying that existing capacity would be taken up sooner. In its assessment of non-pipeline transport options, EnSys assumed those options would need to begin scaling up in 2016. The WEO 2012 noted existing pipeline capacity could be fully utilized by 2016.

There are already transportation constraints substantially impacting the prices of WCSB crude oils. As described in Section 1.4.6.3, Rail Potential to Transport WCSB Crude Oil, the benchmark heavy crude, WCS, has been trading at a $30–40 discount from Brent crude for much of the last year, even climbing to $50–60 recently. It appears these recent steep discounts are related not to reaching the limits of cross-border pipeline capacity, but to more temporary constraints within the United States related to maintenance on the Enbridge pipeline system, as well as the delay in the BP Whiting refinery starting its new heavy crude processing units. Even if these constraints are alleviated in 2013, it is likely that cross-border pipeline capacity (as well as the existing Kinder Morgan Trans Mountain pipeline to Vancouver) will be fully utilized by 2016 or earlier. The 2011 Final EIS examined other proposed WCSB pipeline projects, including the Enbridge Northern Gateway project to Kitimat, British Columbia, and the Kinder Morgan Trans Mountain pipeline expansions to the Canadian West Coast. These projects are being reviewed, but face significant opposition from various groups, and they may continue to be delayed. Enbridge is now stating in investor presentations that the Northern Gateway pipeline (525,000 bpd expandable to 800,000 bpd) may be operational by "2017+". Kinder Morgan continues to state in investor presentations that the expansion of the existing Trans Mountain capacity (from 300,000 bpd today to 890,000 bpd capacity based on shipper commitments of 708,000 bpd) is expected to be in service in 2017 (Persily 2013).

Based on observations of the above trends, several analysts have noted that if additional pipeline capacity is not added by 2016, or earlier, then WCSB production could be shut-in, and production would be constrained by limited pipeline capacity (CIBC 2012, TD Economics 2012, Pembina Institute 2013, and Vanderklippe 2013). These analyses, however, do not have a full assessment of the potential for rail and other non-pipeline transport options to scale up in the event no additional pipeline capacity is added. Several of the reports either implicitly or explicitly assume there would be no substantial increase in transporting crude oil by non-pipeline options without explaining that assumption.[24] Other reports acknowledge that rail transport of crude oil could grow, but do not include a full assessment of the potential of other non-pipeline transportation options or provide detailed information regarding their assessment of rail potential.[25]

Pipelines have long been the preferred method of transportation for crude oil producers and shippers for long-term, relatively stable commitments. In situations where pipeline capacity is constrained, however, producers and shippers will utilize other modes of transportation, including rail, to ship large volumes of crude oil, as long as such modes are economical. As noted in the next section, rail shipments of crude oil throughout North America have increased substantially in the past 2 years because of limited pipeline capacity out of new production areas. The two Class I Canadian railroads are currently estimated to be transporting over 200,000 bpd (up from 20,000 bpd in 2011) (American Association of Railroads [AAR] 2012; CAPP 2012). Review of market information suggests the rail capacity to ship heavy oil sands crudes is expected to expand significantly beyond that by 2014.

This added rail transport capacity helps alleviate the transport constraints identified in the analyses cited above, and additional rail capacity has the potential to accommodate WCSB growth in the event no pipeline capacity is added. That rail (supported by barge and tanker) could accommodate all projected WCSB growth was a key conclusion in the EnSys 2011 report and is explored further in the next section. The assessment of WCSB transportation possibilities in the following section assumes that no new United States-Canada cross-border, or other WCSB export, pipeline capacity is added between now and 2035.

[24] "While shipping by rail is in the pilot stages, in 2011, only 20,000 barrels of crude oil per day left western Canada on rail. This volume may well grow in the future, but relative to large diameter pipelines, rail's contributions to total exports will remain very small" (Pembina 2013). A second report just noted that rail is more expensive than pipelines and that pipelines are a safer mode of transport (TD Economics 2012).

[25] The CIBC report indicated it did not believe rail would continue longer term when new pipeline projects were implemented, "unless pricing North of Cushing (Bakken and Canada) are discounted due to lack of pipeline capacity – which would be a factor if Keystone XL does not get built" (CIBC 2012). One analysis assumed shut-in could be partially offset by increases in rail; however, it found it unlikely that rail could provide total proposed Project capacity replacement by 2015 (RBC Capital Markets 2013). The analysis concluded that by 2020, absent the proposed Project, downward pressure on WCSB crude oil prices could result in a decrease in oil sands production by nearly 300,000 bpd versus their base case. That report did not include information regarding its outlook for the potential of rail shipments of crude oil to increase. The discussion of the potential for rail capacity to increase at rates sufficient to transport projected WSCB production is presented in Section 1.4.6.3, Rail Potential to Transport WCSB Crude Oil.

1.4.6 Crude Oil Transportation

The proposed Project is one element in much larger developments in North American crude oil transportation as companies respond to the new sources of crude oil production in both the United States and Canada and construct the infrastructure to move that crude oil to market. The two biggest developments have been in the additions and changes in pipeline capacity within the United States and the addition of rail capacity throughout North America.

1.4.6.1 Increases in Pipeline Capacity

The No Expansion scenario assessed in EnSys 2010 assumed that pipeline capacity would be frozen at 2010 levels for at least 20 years along three routes: 1) from Canada the WCSB across the border to the United States; 2) from the WCSB to the Canadian West Coast; and 3) from PADD 2 (Midwest) to PADD 3 (Gulf Coast) in the United States. The scenario represented a situation in which neither major new pipeline projects nor modifications and expansions to existing pipelines went ahead. The EnSys 2011 report concluded that such a scenario was unlikely. Even if a small number of major new projects did not go ahead, notably Keystone XL (which had not been approved) and Northern Gateway (which was open to uncertainty), there were many options the midstream industry possessed to modify existing pipelines and/or make use of existing rights-of-way. These options would be explored before turning to non-pipeline modes, which are also potentially significant as discussed below.

The EnSys 2011 report identified a range of then-announced projects plus additional potential projects that would start from existing infrastructure and which could add materially to the capacity to export WCSB crudes and/or movement of U.S. Bakken and Midcontinent crudes to markets. Since August 2011, when the report was published, the number of projects entailing modifications and/or use of existing rights of way has expanded. Table 1.4-7 summarizes current projects, either under construction or where there is commercial commitment, that would directly support the export of WCSB crudes and/or move WCSB and Bakken crudes to destination markets. Again, nearly every project entails either modification to existing facilities or use of existing right-of-way.

While no new additional pipeline capacity has been added from Canada into the United States or to the Canadian West Coast since the Final EIS in 2011, a number of projects are proposed, including this proposed Project. The 300,000 bpd Kinder Morgan Trans Mountain pipeline that runs from Edmonton to the British Columbia coast at Vancouver, with a spur to Washington State refineries, has been over-subscribed for some time. A successful open season led the Kinder Morgan to announce and file for expansion to 750,000 bpd by potentially 2017. After a second open season, Kinder Morgan has increased the expansion to 890,000 bpd. The bulk of the incremental crude moved on the line would potentially be destined for Asia. The review process for this project is continuing, but there is significant opposition based on concerns over environmental impacts associated with the oil sands and with additional tanker movements in the Port Vancouver harbor.

Table 1.4-7 Major New Crude Oil Transportation Expansion Projects, Late 2011 to Current

Pipeline	Crude type	Route	Date In Service	Date Announced/Last Announcement	New Capacity/ Expansion (bpd)	Capacity after Expansion(s) (bpd)
Plains All American Bakken North	Bakken	From Trenton, Montana, to Regina, Saskatchewan	2012	6/8/2012	50,000	50,000
Enbridge Bakken Pipeline	Bakken	From Berthold, North Dakota, to Cromer, Manitoba	2013	8/24/2010	120,000	145,000
Enbridge Sandpiper Pipeline	Bakken	Beaver Lodge, North Dakota, to Superior, Wisconsin	2016	12/7/2012	To Clearbrook: 225,000 Clearbrook to Superior: 375,000	375,000
Enbridge Alberta Clipper/Line 67 Expansion	WCSB	From Hardisty, Alberta to Superior, Wisconsin	2014	12/7/2012	350,000	800,000
Enbridge Southern Access Expansion/ Line 61 Enhancement	WCSB and Bakken	From Superior, Wisconsin to Flanagan, Illinois	2014	5/16/2012	160,000	1,200,000
Enbridge Flanagan South	WCSB and Bakken	Flanagan, Illinois to Cushing, Oklahoma	2014	3/26/2012	585,000	800,000
Enbridge Line 5 Expansion[a]	WCSB and Bakken	Superior, Wisconsin to Sarnia, Ontario	2013	12/7/2012	50,000	540,000
Enbridge Line 6B Replacement and Expansion[a]	WCSB and Bakken	Griffith/Hartsdale, Indiana to Sarnia, Ontario	2013/14	12/7/2012	260,000	500,000
Enbridge Line 9B Reversal and Line 9 Capacity Expansion[a]	WCSB and Bakken	From North Westover, Ontario to Montreal, Quebec	2014	12/7/2012	60,000	300,000
Enbridge/Energy Transfer Partners Natural Gas to Crude Conversion	WCSB, Bakken	Patoka, Illinois to Gulf Coast area	2015	2/15/2013	660,000	660,000
Kinder Morgan Pony Express[b]	Niobrara, Bakken	Guernsey, Wyoming to Cushing, Oklahoma	2014	8/1/2012	220,000	220,000
Enbridge/Enterprise/ Seaway Reversal and Expansion Phase I	Midcontinent, WCSB, Bakken	Cushing, Oklahoma to Gulf Coast area	2012	11/16/2011	150,000	150,000
Enbridge/Enterprise/ Seaway Reversal Phase II	Midcontinent, WCSB, Bakken	Cushing, Oklahoma to Gulf Coast area	2013	11/16/2011	250,000	400,000
Enbridge/Enterprise/ Seaway Reversal Phase III	Midcontinent, WCSB, Bakken	Cushing, Oklahoma to Gulf Coast area	2014	3/26/2012	450,000	850,000
TransCanada Gulf Coast Project	Midcontinent, WCSB, Bakken	Cushing, Oklahoma to Gulf Coast area	2013	2/27/2012	830,000	830,000
Totals					**4,570,000**	**7,820,000**

Sources: Ellerd 2012; Enbridge 2010; Enbridge 2011a; Enbridge 2011b; Enbridge 2012a; Enbridge 2012b; Enbridge 2012c; Enbridge 2012d; Industrial Commission of North Dakota 2012; Smith 2012; TransCanada 2012; Reuters 2013; Pipeline companies' websites and industry press announcements.

[a] Enbridge Line 5, 6B and Line 9/9B are components of their "Eastern Access" project.

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Enbridge has made regulatory filings[26] to expand one of its heavy crude pipelines, Line 67, (also known as Alberta Clipper), from Hardisty Alberta, to Superior, Wisconsin, by 120,000 bpd to 570,000 bpd, with potential to go to 800,000 bpd. The company has also announced that it has shipper support to add a new pipeline from Edmonton to Hardisty with stated initial capacity of 570,000 bpd, expandable to 800,000 bpd, and a potential 2015 in-service date.

In addition, as summarized in Table 1.4-7, there is substantial pipeline capacity coming online to take WCSB crude oils through the U.S. heartland and out to markets in both the Gulf Coast and Eastern Canada. Most of these projects would also support taking either Bakken, Rocky Mountain, or Midcontinent U.S. crudes to these same markets. These projects are, for the most part, in addition to those known during the development of the 2011 Final EIS.

Plains All American and Enbridge have projects that will take Bakken crude either north (back up into Canada) or east, in all cases connecting in to the Enbridge Mainline system that runs cross-border into northern PADD 2. Enbridge, and also Kinder Morgan, are expanding capacity to bring crude oils from northern PADD 2, (Chicago area), and PADD 4 south to Cushing, which continues to be expanded as a crude oil hub. Expansions are also being made to pipelines from West Texas, Oklahoma, and Kansas into Cushing to bring in growing production from those regions.

Enbridge has an array of projects under the heading “Eastern Access” to increase capacity to take WCSB, and also potentially Bakken, crudes to refineries in eastern PADD 2 but primarily in Sarnia, Ontario, and potentially Quebec and Montreal. In association with these projects, which include the re-reversal of Line 9 so it again runs east from Sarnia to Montreal, is the possible reversal of the Portland, Maine, to Montreal pipeline to also run east.

The U.S. crude logistics system has, until recently, included only one pipeline, the 93,000 bpd Pegasus line, that runs from PADD 2 to PADD 3 (the Gulf Coast). This was because, historically, the flow of crude oils was northward from PADD 3 to PADD 2. In 2012, reversal of the existing Seaway pipeline was completed so that it now runs south from Cushing to the Gulf Coast. Initial capacity of 150,000 bpd in the reversed direction was increased to 400,000 bpd in January 2013 by adding pumping capacity. The owners of the pipeline are also twinning it, adding another 450,000 bpd of capacity for a total of 850,000 bpd. Construction on TransCanada’s Gulf Coast Project is proceeding[27], which would add another 830,000 bpd of transport capacity between those locations, again, from Cushing to the Gulf Coast. Just recently, Enbridge and Energy Transfer Partners, LP, announced plans to convert one of three pipelines of the Trunkline system from natural gas transmission to crude oil service, which would allow transport of up to 660,000 bpd from Patoka, Illinois, to the Gulf Coast area. These combined projects add a total of 2.34 million bpd of new pipeline capacity between PADD 2 and PADD 3 that did not exist when the Final EIS was published.

In general, the projects listed in Table 1.4-7 are expected to be in service in 2013 or 2014. They constitute a subset of the total array of pipeline projects under way at present. Substantial additional capacity is also coming on stream to move Eagle Ford crude to the Gulf Coast and, as noted, to take expanding West Texas and Midcontinent crude production to Cushing, and thence

[26] This includes an application for a new Presidential Permit currently under review by the Department.
[27] The TransCanada Gulf Coast Project is the renamed southern segment of the previous Keystone XL pipeline project. While originally a single permit application, the project always comprised two separate potential construction projects, northern and southern.

onward to inland destinations and the Gulf Coast. One analysis of the new pipeline developments made in the summer of 2012 calculated that the new pipeline projects (including new construction, expansions, reversals, and the conversion of natural gas pipelines to crude oil service) amounted to a total of over 9 million bpd of additional pipeline capacity to transport crude oil in and through the United States (Hart 2012).

The Enbridge Line 67 (Alberta Clipper) and Southern/Gulf Coast Access expansions would provide a mechanism to compete with the proposed Project to deliver heavy Canadian crude oil into Cushing. In addition, the Seaway and TransCanada (Gulf Coast) projects, together with other pipeline and rail developments, will help relieve the bottleneck at Cushing, which has kept the price of the U.S. benchmark light, sweet crude oil, West Texas Intermediate (WTI), discounted heavily versus similar light, sweet crude prices on the Gulf Coast and world markets since early 2011.

The Final EIS and EnSys 2011 had noted that projects for interstate petroleum pipelines that do not cross an international border face less regulatory review, especially when they entail modifications to existing lines or rights of way, which was one of the reasons a complete No Expansion shut-in of new capacity was considered unlikely. The development of these projects supports that assessment, and supports the view that, in general, absent larger regulatory changes one can expect infrastructure developments to follow market patterns of supply and demand, which EnSys had described as “business as usual”. These firm projects add up to a major and on-going re-working of the U.S./Canadian crude oil pipeline logistics system as the industry adapts to changing market conditions precipitated by the growth in WCSB and Bakken and Midcontinent production. In addition, other possible projects are constantly being considered. The following are two important current examples that have been discussed as possibilities (no action has been taken on either):

- A possible TransCanada project to convert one or more existing natural gas pipelines that run from Alberta to Ontario and on to Quebec to crude oil service. Potential capacity has been reported as up to 600,000 bpd with capability to carry both light and heavy/oil sands WCSB streams.
- Possible reversal of the 1.2 million bpd Capline system that runs from the LOOP terminal and St. James in Louisiana to the Patoka pipeline and storage hub south of Chicago. Traditionally this line has been used to move imported and Gulf of Mexico crudes into the Midwest. Throughputs have dropped dramatically in recent years as supply of both WCSB and Bakken and Midcontinent crudes into the Midwest has built up.

In short, the logistics system is adapting, but there remain substantial price discounts on WCSB and inland Bakken and Midcontinent crude oils attributable to transport infrastructure constraints.

The next sections address how rail capacity has increased to accommodate the changing production patterns and ends with a discussion regarding how the price discounts noted here are creating overriding incentives to use alternate modes of transport.

1.4.6.2 Increases in Rail Capacity

While no new pipeline capacity has been added since 2011 across the Canada-United States border or to the Canadian West Coast, the development of rail as a viable, large-scale transport option for crude oil does potentially add significant transport capacity along these and other routes.[28] As noted in the Final EIS, the linear infrastructure (railroad tracks) necessary to transport crude oil in large volumes out of the WCSB is already in place. To utilize rail at large scale, producers and/or shippers would need to build loading and unloading facilities and add tank car capacity. Both of those activities are presently underway, and there already has been a sharp increase in rail transport of crude oil. The developments to date, as well as a review of industry information, indicate that, especially as long as pipeline capacity is constrained, significant quantities of crude oil will be transported by rail, including out of the WCSB. Although this section focuses on rail, rail is also being used with barge and tanker to deliver crude oil to refineries.

The leading production area that has developed rail, including the construction of dedicated terminals for loading unit trains[29] to transport crude oil, is in the Bakken in North Dakota and Montana. Pipeline capacity out of the Bakken has not kept pace with the increases in production in the region. Rather than allow the production there to be shut-in, companies have responded with significant additional rail capacity and have been able to do so very rapidly.

When the Final EIS (and the EnSys Reports) were prepared, rail shipments were just beginning to occur in large quantities from the Bakken. When EnSys 2010 was completed in December 2010, only approximately 50,000 bpd of crude oil were being shipped by rail. There was capacity at rail facilities to load approximately115,000 bpd of crude oil. When the Final EIS was released in August 2011, there were approximately 80,000 bpd of crude oil being shipped by rail, and capacity to load approximately 275,000 bpd of crude oil. Since the Final EIS was published, however, the volume of crude oil transported by rail out of the Bakken area has more than quadrupled to approximately 500,000 bpd and could exceed 800,000 bpd by the end of 2013. (These developments are shown in Table 1.4-8 and Figures 1.4.6-1 and 1.4.6-2.) Thus, the midstream and rail companies operating in the Bakken and at receiving terminals on the U.S. Gulf, East, and West Coasts have demonstrated an ability to rapidly develop rail infrastructure and movements on a large scale.

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[28] For example, the Express Pipeline, terminating in Casper, Wyoming, with a capacity of 280,000 bpd, is underutilized because the Platte Pipeline to which it connects has a capacity of approximately 150,000 bpd. There are proposed rail facilities that could provide onward delivery for additional quantities of WCSB heavy crude delivered to Casper.

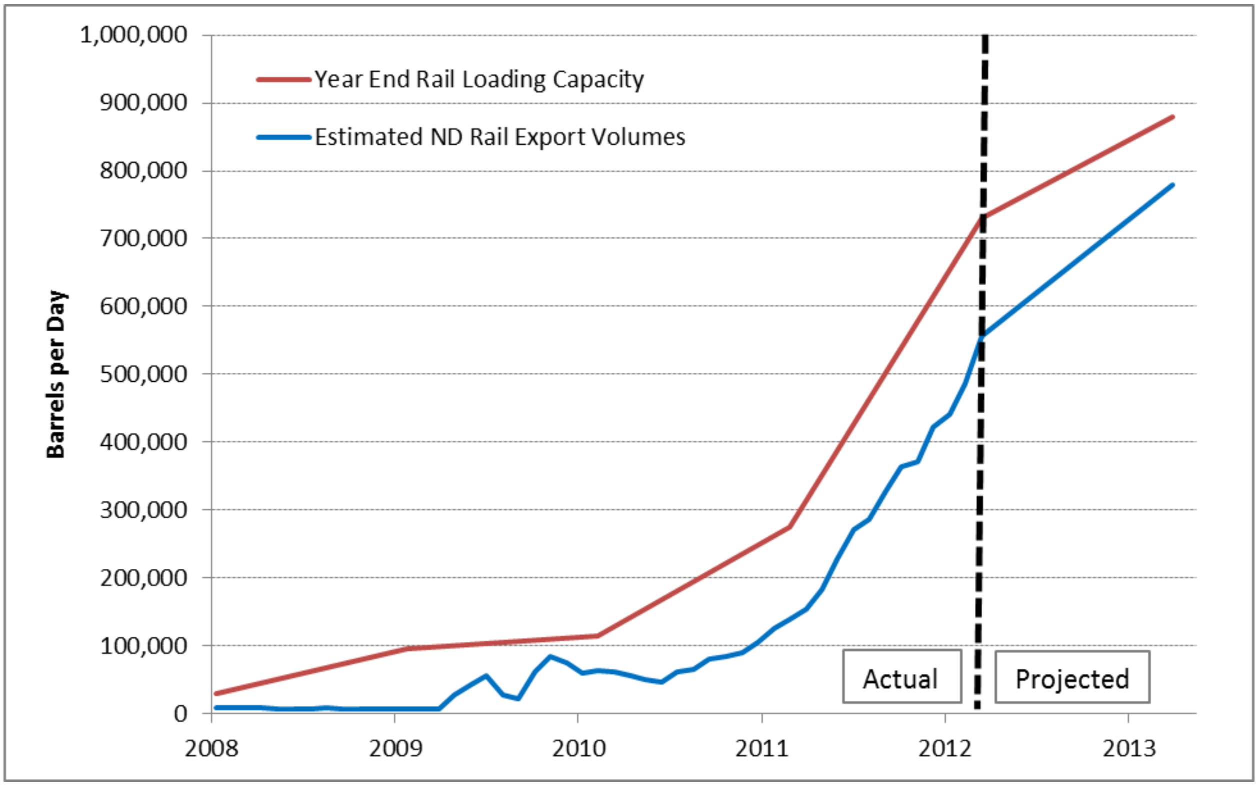
[29] A “unit train” is a train that carries one commodity and transits from origin point to one destination point. A crude-oil unit train is typically 100 cars long. As noted in EnSys 2011, before 2010 virtually no unit trains were being utilized to transport crude oil. Unit trains have been utilized for many years to transport other bulk commodities, such as coal.

Table 1.4-8 Rail Off-Loading Projects Providing Access to Gulf Coast Refineries

Crude-by-Rail Terminal/Operator/Owner(s)	Incremental Capacity (bpd)	Date In-Service
Gulf Coast Area Destination Terminals		
Cima Energy/Houston, TX	65,000[a]	2011[a]
GT Logistics GT Omni Port/Port Arthur, TX	125,000	2012
Nustar-EOG Initial Startup/St. James, LA	12,000	2011
Nustar-EOG Phase 2 Start/St. James, LA	58,000	2012
Nustar-EOG Phase 2 Realization Phase/St. James, LA	30,000	2012
Nustar-EOG Phase 3/St. James, LA	40,000	2012
U.S. Dev. Group Phase 1/St. James, LA	65,000	2011
U.S. Dev. Group Phase 2/St. James, LA	65,000	2012
Triafigura Texas Dock and Rail/Corpus Christi, TX	65,000[a]	2013
Crosstex Energy, Phase 1, Riverside, LA	14,500	2012
Crosstex Energy, Phase 2, Riverside, LA	30,000[a]	2015[a]
Watco Greens Port Industrial Park/Houston, TX	65,000[a]	2011
Sunoco, Nederland, TX	15,000	2012
Canadian National/Arc, Mobile, AL	25,000	2013
Genesis Energy, Natchez, MS	12,000	2013
Estimated Total	**686,500[a]**	
Cushing, Oklahoma Terminals		
EOG Stroud OK to Cushing, OK	60,000	2011
Watco—Kinder Morgan Energy Partners/Phase 1/Stroud, OK, to and from Cushing	140,000	2012
Watco—Kinder Morgan Energy Partners/Phase 2/Stroud, OK, to and from Cushing, OK	140,000	2015[a]
Total	**340,000**	
PADD II Rail to Barge/Marine Transloading		
Seacor Energy—Gateway Terminals/Sauget, IL	130,000	2011
Marquis Energy/Hayti, MO	42,800	2012
Marquis Energy/Hennepin, IL	35,700	2012
Total	208,500	
Grand Total	**1,235,000**	

Source: Hart Energy 2012; company public disclosures, media reports.

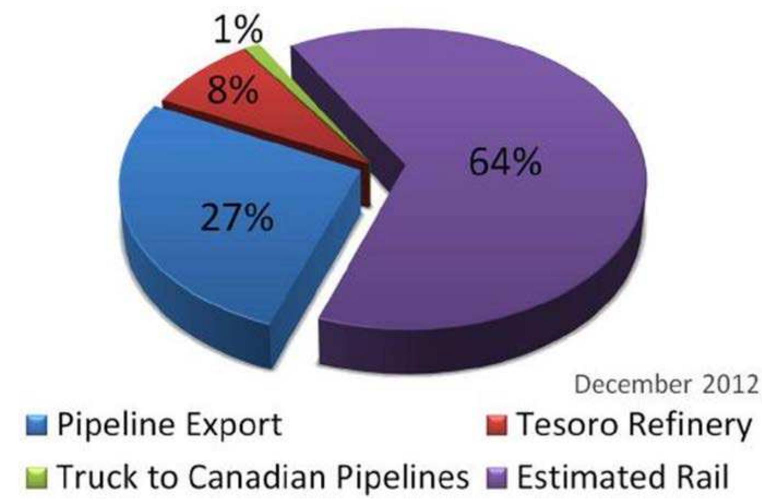
[a] Estimated.



Source: North Dakota Pipeline Authority 2013; company reports.

Note: The 2013 estimate of volume of crude oil shipped from the Bakken is based on rail company statements.

Figure 1.4.6-1 Estimated Rail Export Volumes and Projected Rail System Capacity, North Dakota



Source: North Dakota Pipeline Authority 2013b

Figure 1.4.6-2 Williston Basin Crude Oil Transportation, December 2012

Rail is now utilized to transport more than 50 percent of the crude oil out of the Bakken (compared to 32 percent by pipelines). This trend is expected to continue, even though "takeaway" pipeline capacity from the Bakken area is expanding. In contrast to rail takeaway capacity, which is moving Bakken crudes predominantly to coastal markets, the pipeline takeaway projects generally only move Bakken crude into the Enbridge Mainline system in the upper Midwest and therefore encounter the current pipeline bottlenecks in PADD 2. BNSF Railway (BNSF), the largest rail operator in the Bakken that transports approximately 80 percent of the crude by rail from the area, recently announced that in 2012 it made upgrades on its tracks such that it can now accommodate up to 1 mmbpd of crude oil out of the Bakken (up from 750,000 bpd) and that it expects its crude oil shipments from the area to grow to 700,000 bpd in 2013 (BNSF 2012; Bloomberg 2013).[30]

The Bakken area has seen the greatest construction of unit-train rail facilities to transport crude oil, but it is not the only area. Such facilities have been or are being constructed in virtually every new production area of the United States to transport crude oil where there is not sufficient pipeline capacity to accommodate the new production, including the Eagle Ford shale in Texas, the Permian basin in Texas, the Woodford/Anadarko area in Oklahoma, the Utica shale in Ohio, and the Niobrara shale in Colorado and Wyoming. Estimates are that there could be from 2.5 to 2.7 mmbpd of rail crude oil loading facility capacity by 2016 throughout these areas (Hart 2012). This represents total potential capacity to load crude oil by train in the United States by 2016, but is not a projection that 2.5 to 2.7 mmbpd will actually be transported by rail. The extent to which these facilities are utilized will depend upon many factors, including the availability of cheaper pipeline transport options from the respective production areas, the world price of oil (notably if

[30] In recent years BNSF has invested in upgrading its track capacity to handle increased crude oil transport. Although BNSF, and other railroads, have made substantial capital investments in their system capacity in areas of the Western United States over the last 30 years to accommodate increased coal transportation (discussed below), those rail lines carrying that coal traffic are different than BNSF's northernmost rail line on which the majority of the Bakken crude oil is being transported.

any drop occurred that were sharp and long enough to curb production), and the discounts between the price of oil paid in the production areas and the price of oil paid at the refinery markets (particularly on the coasts).

Rail off-loading facilities to receive unit-trains of crude oil are also being developed across the country, including at Cushing, Oklahoma, along the inland waterways, on the Gulf Coast, and on the East and West Coasts. Estimates are that there could be from 2.0 to 2.6 mmbpd of rail off-loading capacity at refineries throughout the United States by 2016 (Hart 2012). Of that amount, 1.3 million bpd is at facilities that are either on the Gulf Coast, or would provide easy onward delivery to the Gulf Coast via pipeline (from Cushing) or barge (Table 1.4-8), and many of those facilities identified have space for further capacity if economics warrant adding it.[31] In addition, rail off-loading capacity to serve U.S. East Coast refineries is developing rapidly. Current capacity of around 300,000 bpd is expected to grow to over 800,000 bpd by the end of 2013. This does not include around 70,000 bpd of rail off-loading capacity at the Irving refinery in St. John, New Brunswick.[32] Off-loading capacity on the West Coast is currently approximately 135,000 bpd and is projected to increase to approximately 400,000 bpd.

Although crude oil transport by rail predates that via pipeline, one of the primary reasons that pipelines have been preferentially used over many years is because the cost of rail transport of crude oil has generally been significantly higher than pipeline. The relatively higher costs of rail transport have not appeared to be a significant economic disincentive to producers in the Bakken. Recent press reports indicate that shippers out of the Bakken are utilizing rail transport even when pipeline capacity is available because it provides them access to markets not served by pipeline and where they can obtain better prices for the crude.

Part of the reason rail has become a more competitive alternative in the Bakken is that essentially all the rail capacity out of the region uses so-called “unit train” technology which entails loading and moving large dedicated crude oil trains. This has improved rail economics versus the traditional “manifest” trains. Rather than leave crude oil shut-in, the Bakken producers are finding it profitable to make use of rail, which was estimated in December 2012 to be transporting approximately 500,000 bpd out of the region. The EIA has also noted that transportation constraints have not appeared to result in production being shut-in in the United States:

> The phrase "transportation constraints" refers to a broad range of logistic issues, with inadequate pipeline capacity being the most common issue. EIA is not aware of any crude oil production capacity being shut in because of a lack of capacity to move the oil. (EIA 2012f)

[31] Much of the public reporting surrounding the construction of these terminals has focused on their ability to accept light crude. If rail cars hauled dilbit at pipeline specifications, they could unload at any of the terminals indicated (EnSys 2011). Hauling raw bitumen or railbit requires special handling equipment. The terminals in Mobile, Alabama, and Natchez, Mississippi, are being designed specifically to handle heavy crude, in the form of railbit or raw bitumen transported in insulated rail cars with steam coils, which would then be loaded on to barges for onward delivery to refineries throughout the Gulf Coast. Outside of the Gulf Coast, PBF Energy has also specified it is leasing railcars that can transport undiluted bitumen to its Delaware City, Delaware, refinery, and that it expects to ship 40,000 bpd of bitumen, or more, in 2013.

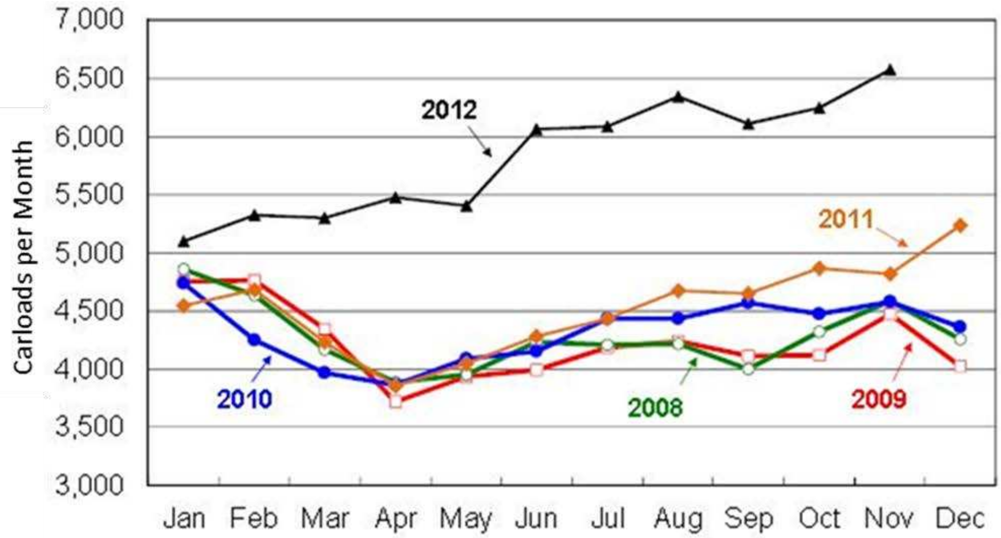
[32] A recent report indicates the Irving Refinery is moving more than 90,000 bpd, receiving Alberta crude directly by rail, and Bakken crude by rail to a port in Albany, New York, and shipped via tanker to the Saint John refinery (Penty 2012).

The Final EIS had examined the rail developments in the Bakken as an example of how rail transport could be increased to transport large quantities of crude oil when there are pipeline constraints. The continued development of rail capacity in the Bakken, and throughout the new production areas in the United States, reinforces that view.

A similar trend in increased rail transport is beginning to occur in Canada in the WCSB area. The lack of any new pipeline capacity westward to the British Columbia coast or eastward within Canada to the Sarnia area is combining with bottlenecks in the Enbridge Mainline system in the Chicago area to constrain WCSB crude exports and create today's severe price discounts versus international marker crudes. In addition, other factors such as the delay in the start-up of the upgrade project at the BP Whiting refinery to process additional heavy crude add to the constraints. A series of linked projects is under way by Enbridge to alleviate the bottlenecks out of northern PADD 2 to the Cushing area and Gulf Coast and to eastern Canada (Section 2.2, Description of Reasonable Alternatives). These are expected to be mainly complete by 2014. However, continued growth in both WCSB production and that of Bakken and Midcontinent crude oils competing for space on the same pipeline system is likely to lead to continued constraints on WCSB export capacity based on current firm pipeline projects—and before accounting for rail options.

There are two major rail operators in Canada, Canadian National and Canadian Pacific. Both have been promoting crude-by-rail as an option for transporting crude oil out of the WCSB to destinations throughout the United States and Canada. In mid-2012 each carrier projected that it would transport approximately 100,000 bpd in 2013, or approximately 200,000 bpd total (Tomesco 2012). Data from the AAR suggests that Canadian National and Canadian Pacific may already be transporting be transporting approximately 200,000 bpd of crude oil (Figure 1.4.6-3).[33] It estimated that 120,000 bpd of this is from the WCSB, and 80,000 bpd is from the Bakken (Peters & Co. Limited 2013).

[33] This estimate was arrived at by comparing two calculations. The AAR weekly rail traffic summary indicates that in December 2012, and January 2013, Canadian National and Canadian Pacific were originating an average of just over 7,000 rail cars per week in the Petroleum Products category. First, a calculation was made based on a December 2012 AAR report that indicated 38 percent of the "Petroleum Products" category for carload originations in the United States and Canada was crude by rail. Assuming a conservative 600 barrels per carload, this would be 225,000 bpd. Second, the increase in the Petroleum Products category for Canadian carload originations from December 2010 to December 2012 was assumed to be 90 percent crude by rail (based on industry statements), which (with the same 600 barrels per carload) would be an increase of 190,000 bpd. Further, based on information from Canadian Pacific in their fourth quarter 2012 earnings call with investors, it is estimated that in January 2013 Canadian Pacific was transporting between 110,000 and 130,000 bpd of crude oil. Also on that call, Canadian Pacific officials noted they expect to double or triple the amount of crude they transport.

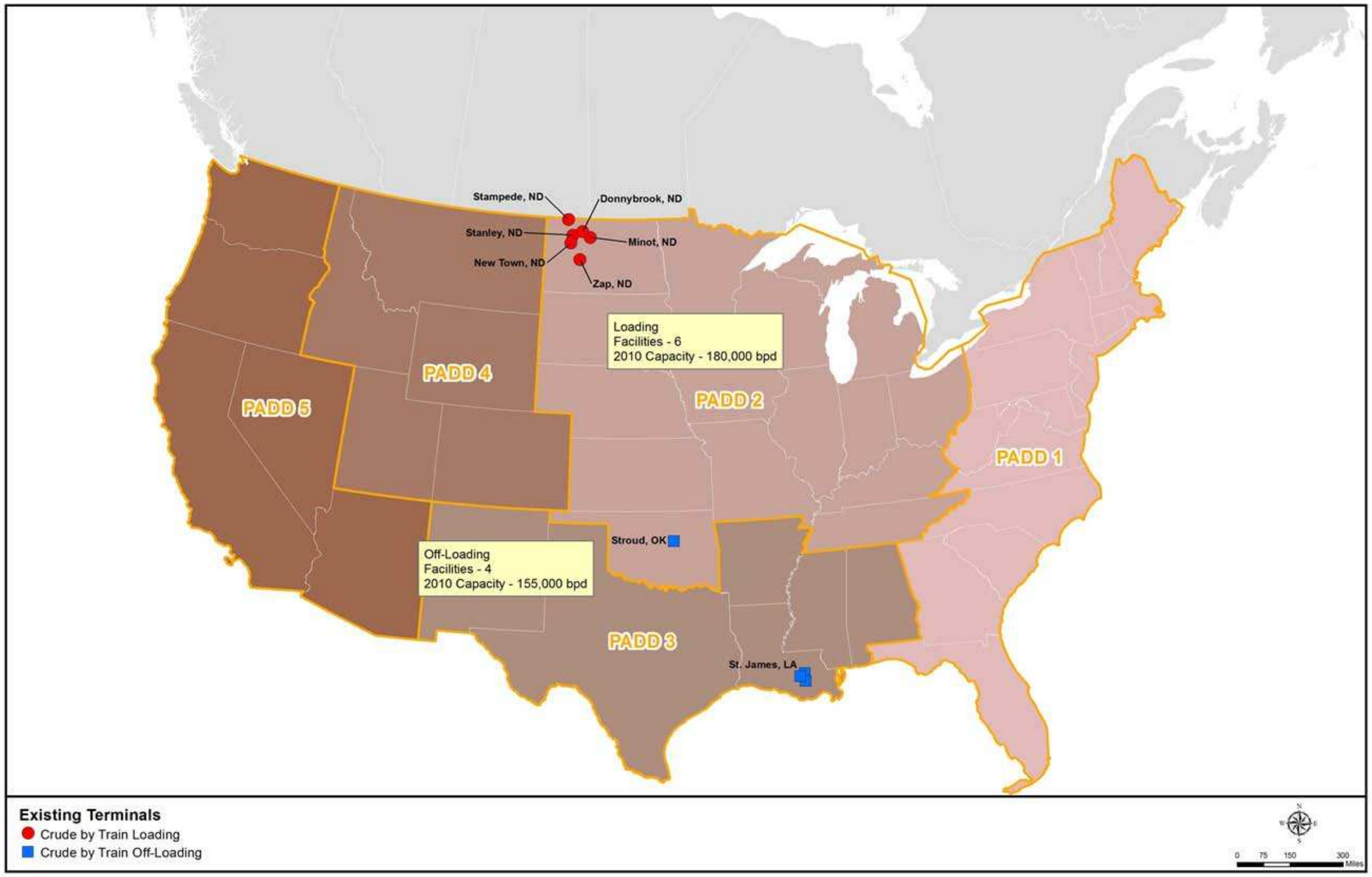


Source: AAR 2012

Figure 1.4.6-3 Actual Canadian National and Canadian Pacific Petroleum Products Transported, Carloads per Month

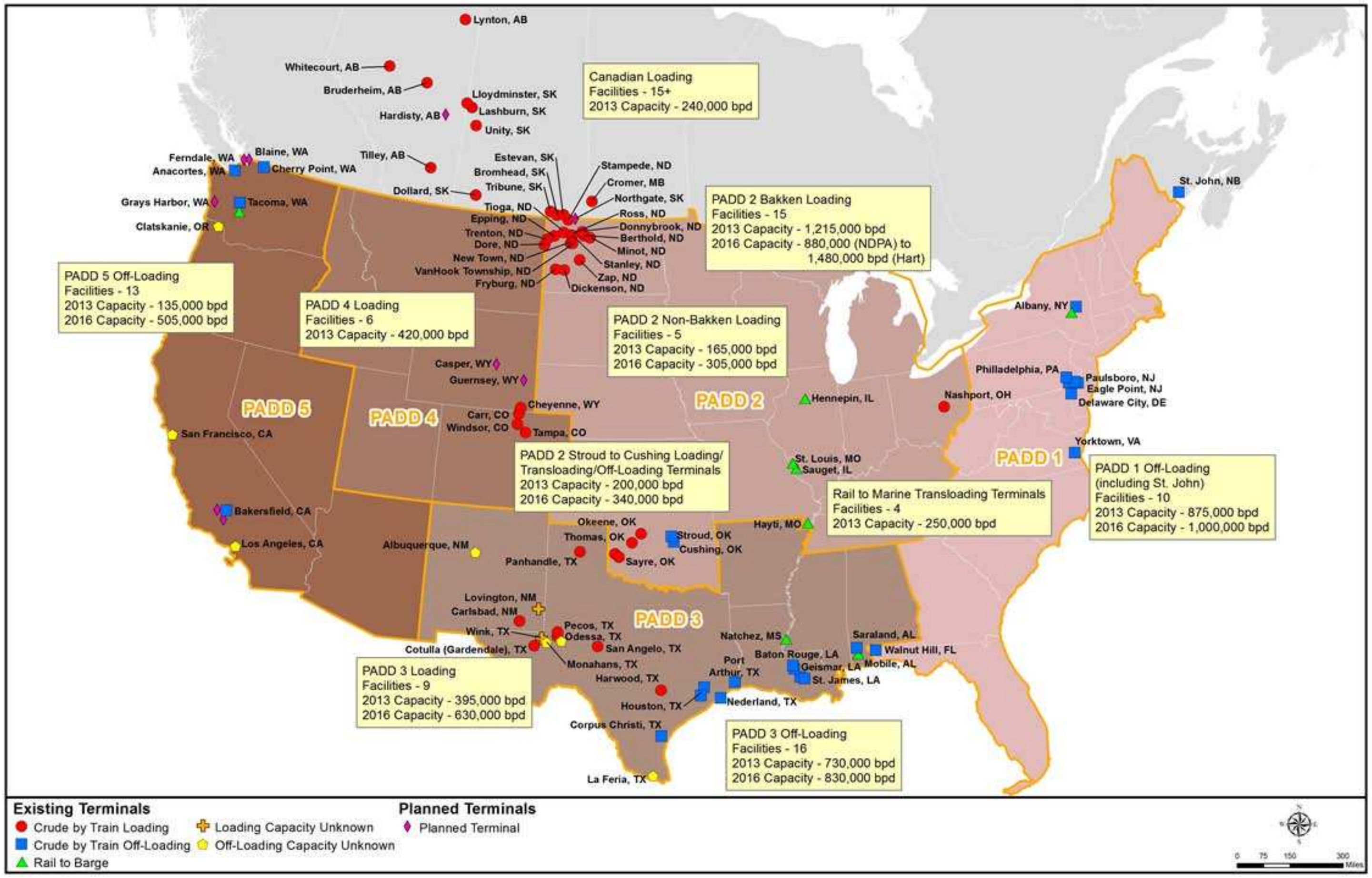
As noted in Section 1.4.5 (Pipeline Capacity out of WCSB) if the existing pipelines were the only transport option for crude oil out of the WCSB, the total transport capacity would be full by 2016 or sooner. This estimate ignores the increasing capacity of rail transport capacity in the WCSB. A more accurate calculation of current transport capacity out of the WCSB would be the current pipeline capacity, plus existing rail capacity. Any assumption that rail will stay frozen at that level would be inconsistent with the developments described above. The potential for rail to further increase its capacity to transport WCSB production is assessed in the next section.

The development of unit train loading, off-loading, and transloading facilities for crude oil since 2010 is illustrated in Figures 1.4.6-4 and 1.4.6-5. As noted, transporting crude oil by unit train requires the construction of specialized facilities that can handle the loading or unloading of a full 100-car train. Before 2010 virtually no unit trains were being used to transport crude oil. The crude oil that was transported by train was done as manifest shipments, and would have likely been as a smaller number of cars in a train with a variety of goods and commodities. As a result, although crude oil was being shipped by train (and refineries and terminals had facilities to handle crude oil and refined products by rail), there were very few facilities that were capable of handling unit trains. This is reflected by the estimate of loading and unloading facilities in 2010 that were capable of handling crude-oil unit trains (Figure 1.4.6-4). At that point the only unit train loading facilities were located in the Bakken area. Unloading facilities were located Stroud, Oklahoma, and St. James, Louisiana.



Source: Hart 2012; Walton 2010; Fielden 2013; NuStar Energy L.P. 2010; North Dakota Petroleum Council 2010; company and media reports.

Figure 1.4.6-4 Crude by Train Loading and Off-Loading Facilities in 2010, Estimated Capacities



Source: Hart 2012; company and media reports.

Note: The number of Canadian loading facilities reflects those identified on the map. Canadian National reportedly will have 14 loading facilities in WCSB by the end of 2013. Specific locations and capacities for those Canadian National facilities are not known. According to company reports, many of those facilities are likely smaller than full-unit train facilities. The locations in San Francisco and Los Angeles are listed based on Phillips 66 statements that it is utilizing rail to deliver WCSB heavy crude oil to its California refineries.

Figure 1.4.6-5 Crude by Train Loading, Off-Loading, and Transloading Facilities by PADD, and Estimated Capacities

Figure 1.4.6-4 shows the estimated unit train loading, off-loading, and transloading facilities throughout North America for crude oil and their estimated capacities in 2013 and 2016. The map includes rail to barge or tanker transloading facilities. Nearly all of these facilities have been constructed since 2010. As noted above, in the Bakken, most of the additional facilities and expansions had not been announced by the end of 2010. There is less publicly available information about the facilities in the WCSB, including about their capacities.

Many of these facilities, particularly those for off-loading or transloading to barge, were modifications or expansions of existing terminals. The number of facilities and capacities listed in the figure are primarily for facilities reported to be capable of handling unit trains. The facilities identified on the map of "unknown capacity" may not be capable of handling full unit trains. Section 1.8 of Appendix C, Market Analysis Supplemental Information, provides additional information related to these facilities and their estimated capacities and start-up dates.

1.4.6.3 Rail Potential to Transport WCSB Crude Oil

These developments point to the possibility of rail supporting WCSB crude movements in large volume. This section assesses this potential for rail to transport the increases in WCSB production in the 2012 CAPP outlook through 2035, even if no further pipeline capacity is added out of the WCSB. In other words, it assesses the potential of rail to transport the crude oil that would be transported through the proposed Project if the proposed Project were not implemented, and, more broadly, whether rail could accommodate all additional WCSB production if no new pipeline capacity were to be added between now and 2035. In this sense it considers a scenario broader than just a typical "No Action" alternative, as it assumes all proposals for pipeline expansions (beyond those already under construction) do not occur. It does so considering both issues of logistics, need for loading and unloading facilities, track upgrading adding tank cars to the rail fleet, etc. and issues of cost.

Logistics

The 2011 Final EIS analysis and the 2011 EnSys study reviewed the potential for rail as a primary alternative transport mode to support growing Western Canadian production in the event there was no expansion of pipeline capacity. The assessment made under that No Expansion scenario was that export pipeline capacity could limit WCSB export flows beginning around 2016 and that thereafter rail capacity to move Western Canadian crudes to markets would need to be expanded by around 100,000 bpd each year in order to prevent any shut-in of production. This assessment was based on the CAPP 2011 Growth Outlook for Western Canadian crude supply and did allow for other developments, notably the North West Redwater Partnership's upgrader, which it was assumed would add 150,000 bpd of direct bitumen upgrading to finished products by 2020. Nevertheless, the Final EIS assumed rail would have the main burden of supporting Western Canadian supply growth under a No Expansion scenario.

Since 2011, the CAPP has raised its estimates of Western Canadian production and supply to market. Based on the CAPP 2012 outlook for Canadian production, if no new pipeline capacity is added, other transport modes, notably rail, would need to be capable of transporting that annual expansion of approximately 175,000 bpd each year in order to keep up with (and prevent shut-in of) the increases in Western Canadian crude supplies.[34]

A key question is whether rail capacity could grow at such a rate. In order to do so from a logistics perspective, there would need to be development of loading and unloading facilities, of existing track capacity to accommodate additional traffic, and in rail tank car availability. These capacity additions would need to be capable of being sustained year after year to match WCSB crude supply increases. As detailed below, the current growth of rail in Canada (and also the United States) suggests that rail loading capacity could increase as necessary, and is already increasing, to keep pace with the latest CAPP projections. Other factors discussed below point to the potential for rail capacity growth to be sustainable and scalable to large volume over time, thus matching WCSB production growth and avoiding shut-in of WCSB production regardless of pipeline capacity.

As noted above, Canadian National and Canadian Pacific may already be carrying approximately 200,000 bpd. In 2012, Canadian National had approximately 14 crude oil loading facilities completed or under construction, up from just two in 2010. Other midstream operators are constructing crude-by-rail terminals that can accommodate unit trains, and at least eight publically reported WCSB producers are currently shipping or have announced shipping heavy crude by rail in 2013 (Table 1.4-9).

Table 1.4-9 Publically Reported Producers Currently Shipping or Announced Shipping WCSB Crude by Rail 2013, bpd

	2012 (bpd)	2013 (bpd)
Cenovous	5,000	10,000
Suncor	5,000	20,000–25,000
MEG Energy	0	32,000–40,000
Baytex	10,000	15,000
Connacher	10,000	10,000
Crescent Point	16,000	50,000
Southern Pacific	0	12,000
Grizzly	0	5,000
Devon	NA[a]	5,000–10,000

Source: Company releases, media reports.

[a] NA = not applicable.

[34] This estimate is based on rail capacity being 200,000 bpd in 2013 and increasing from that amount. Total WCSB export pipeline capacities are based on the CAPP 2012 outlook.

Also as noted above, rail on- and off-loading facilities have been constructed at a similar pace over the past 2 years throughout the United States, with an estimated 1 million bpd of off-loading capacity in place by the end of 2012 that provides access to Gulf Coast refineries.[35] The operators of many of those existing facilities have indicated in various public disclosures that their facilities can be expanded if market conditions warrant. Whereas constructing a new rail facility takes 12–18 months, expansions at an existing facility can be completed more quickly—in 6–12 months.

The EnSys 2011 study found that the rail systems of the United States and Canada were not at that time running at capacity, that there is significant scope to expand capacity on existing tracks through such measures as advanced signaling, and that adequate cross-border Canada/U.S. capacity exists to accommodate growth in rail traffic that would be associated with movements at the level of 100,000 bpd cross-border increase per year or appreciably higher. In addition, rail lines exist to ports on the British Columbia coasts (notably Prince Rupert, Kitimat, and Vancouver), which could be used for export of Western Canadian crudes.[36]

A single rail line, with a single track and the most sophisticated signaling system can accommodate up to 30 trains per day. Putting a double track along that line, which can be done without need for regulatory approval from the Surface Transportation Board, expands the potential capacity to 75 trains per day (Cambridge Systematics 2007). By comparison, U.S. Department of Transportation data presented in the EnSys 2011 report showed that, in 2010, there were 11 active rail border crossings with Canada from Washington to Minnesota. Those border crossings were running at levels of 2–20 (total) trains per day.[37]

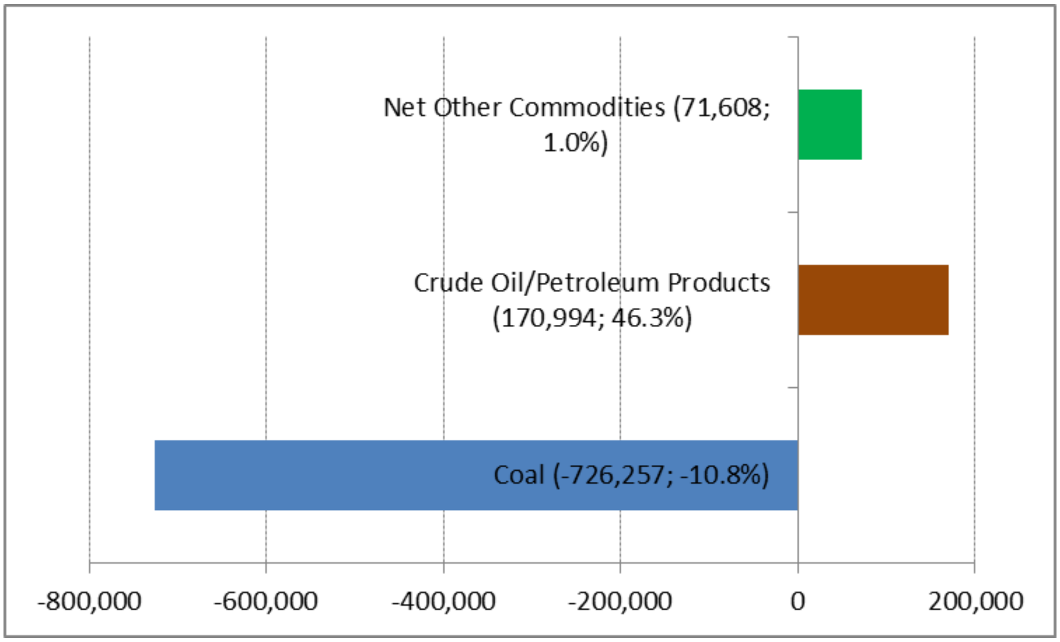
The Cambridge Systematics study assessed possible investment needs in rail infrastructure to accommodate economic growth and increased rail traffic through 2035. The report concluded that with adequate capital investment, the rail system could accommodate increased rail traffic without encountering capacity issues. A subsequent report prepared for the Surface Transportation Board concluded that the economic growth outlook relied on by the Cambridge Study may have overstated the potential additional rail traffic (Christensen 2009). For example, the forecast relied on by the Cambridge Systematics study had projected coal rail tonnage in the western United States to increase by more than 200 percent by 2030. More recent AEO forecasts have coal production in the western United States growing by less than 20 percent over that same time period (Christensen 2009; EIA 2012). For grains, the Cambridge Study relied upon a projected growth in transport of approximately 80 percent by 2035, whereas subsequent U.S. Department of Agriculture production forecasts showed less than a 40 percent increase over that period (Christensen 2009). The Christensen report concluded that the rail system would require lower levels of capital investment to accommodate projected growth in rail traffic than had been indicated by the Cambridge Study.

[35] The Gulf Coast would be the primary market for heavy WCSB crudes, but smaller volumes are already moving to U.S. and Canadian East Coast refineries. The U.S. West Coast could also be a potentially large market for heavy WCSB crudes but California Law AB32, which instituted a low-carbon fuel standard, may well act to limit the volumes of oil sands streams that could be processed in the state.

[36] Nexen Inc. is exploring moving oil by rail to Prince Rupert, British Columbia, to export crude onto tankers for delivery to Asia markets (Vanderklippe 2013b).

[37] The same data source showed that petroleum was being moved from Canada into the United States at nine of the 11 rail crossings from Washington to Michigan in 2010.

Recent trends in the movements of commodities by railroads are consistent with the more conservative growth forecasts for rail traffic noted in the Christensen report. Movements of the railroads' primary freight product, coal, have been dropping as plentiful and low-priced natural gas has been increasingly adopted in the power generation sector (Figure 1.4.6-6).



Source: EIA 2013c.

Figure 1.4.6-6 Changes in U.S. Railcar Loads by Commodity, 2011 to 2012

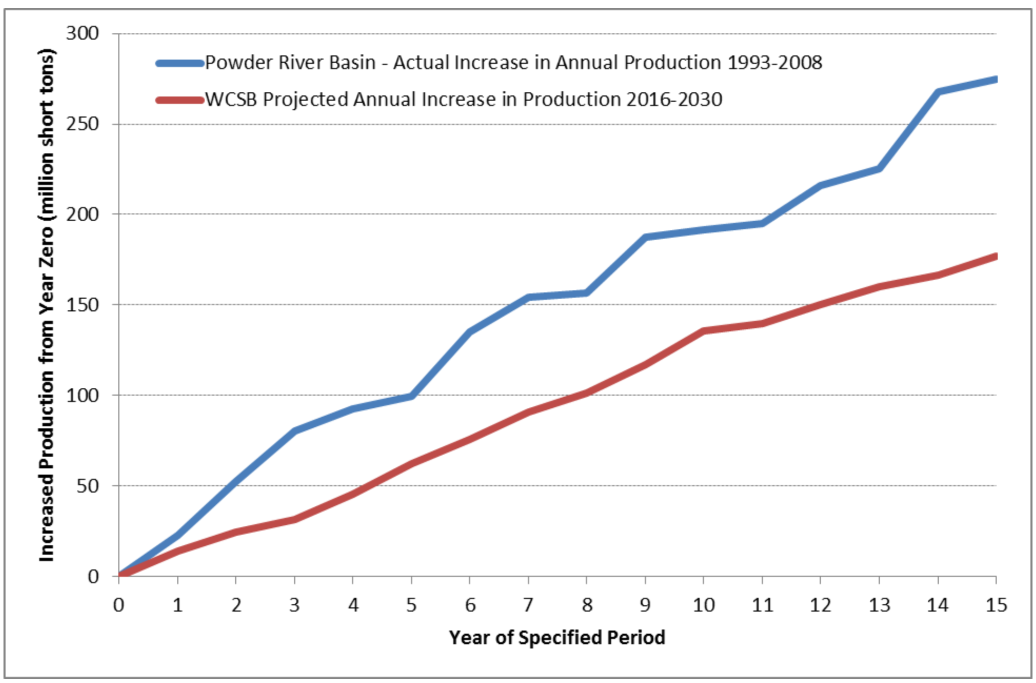
As illustrated in Figure 1.4.6-1, Bakken rail takeaway capacity has risen from 30,000 bpd at the beginning of 2009 to 730,000 in 2012 and is projected to reach 880,000 bpd during 2013. This equates to an average annual rate of approximately 255,000 bpd in the years that the majority of the expansion has been occurring (2011, 2012, and 2013).[38] The claims made by Canadian National and Canadian Pacific as noted above support this view. If such a rate of expansion began in 2013 in Canada, total rail loading capacity out of the WCSB could be over 800,000 bpd by the end of 2015.

The volume of crude oil transported out of the Bakken by rail has grown at a rate similar to that of the development of loading capacity, allowing for loading terminals running below full utilization. As noted above, BNSF has indicated it expects to transport 700,000 bpd by the end of 2013, which would indicate total transport out of the area of 750,000 bpd or more. If that level is achieved, it would be an annual rate of increase of transport in 2011, 2012, and 2013 of approximately 230,000 bpd. This rate of increase of crude oil transported (along with the rate of

[38] The first large crude-by-rail loading facility in the Bakken area was constructed in 2009. The average annual rate of expansion was 170,000 bpd over the five years 2009–2013. Only 85,000 bpd of capacity was added in 2009 and 2010. As noted in the previous section, of the 765,000 bpd of capacity added in 2011, 2012, and 2013, over 500,000 bpd of capacity came from projects that were not yet announced by the end of 2010.

increase in total capacity) indicates that expansion in Canada at an annual rate of around 200,000 bpd of crude oil actually transported should be achievable.

There is no indication that the rail logistics system would not be able to continue to scale up at this rate, or more, over many years if the economics justified it. For example, the rail system was able to expand at an even greater rate, in terms of increased tons hauled per year, to accommodate coal production in the Powder River basin in Wyoming and Montana.[39] The Powder River basin produces approximately 40 percent of the nation's coal, over 400 million tons per year, almost all of which is transported by rail. The first truly large-scale surface mines in the area began operating in the 1970s. By 1980, approximately 99 tons per year of coal were transported out of the Powder River Basin. By 2008, this had increased to approximately 500 million tons, or an average increase of 14 million tons per year every year for 28 years. On a tonnage basis, this is equivalent to an increase of approximately 240,000 bpd per year, or 6.7 million bpd over 28 years. Figure 1.4.6-7 below compares the annual increase in rail transport of crude oil (expressed in short tons) that would be necessary to accommodate projected WCSB production from 2016 to 2030 to the annual increase in tons of coal hauled from the Powder River Basin from 1993-2008, when the most significant expansion in production occurred. This offers further evidence that the rail system (in terms of track improvements and loading facilities) would be capable of making any necessary capacity increases to accommodate all of the WCSB production, provided the economics justified it.



Source: CAPP 2012; Hellerworx, Inc. 2013.

Figure 1.4.6-7 Annual Increases in Rail Transport to Accommodate WSCB Production Compared to Coal

[39] The increase in capacity was not without challenges or setbacks, but nonetheless, even with these challenges the described capacity increases were achieved (USDOE 2007).

In short, there appears to be adequate track and route capacity to multiple destinations and the beginnings of "unit train" terminal developments which would enable movement of Western Canadian crude oil at scale.[40] There also appears to be a proven ability of the rail logistics system (in terms of improving track capacities and constructing loading and unloading terminals) to increase capacity at the rates that would be required to accommodate all of CAPP's projected increase in WCSB production, if the economics warranted such increases. The remaining potential logistics constraint on the expansion of crude oil movement by rail is the ability of the rail car industry to manufacture the necessary additional tank cars. There have been numerous press reports regarding this potential constraint.

According to recent industry reports, current U.S. rail tank car production is close to 5,000 units per quarter, or around 18,000 per year. Orders are shown as around 8,800 per quarter recently with a 2012 industry back-log of around 46,700 cars. This back-log is expected to be cleared during 2014.[41] Depending on shipping origins/destinations, and the grade of crude transported, supplying the 46,700 tank cars during the next 18 to 24 months would add approximately 1.75 million bpd of capability to ship U.S./Canadian crudes by rail. In short, the current back-log is not expected to last long term and the industry appears to be capable of adding enough cars annually to satisfy both U.S. and Canadian growth requirements.

Based on press reports, at least 60 percent of the tank cars now being manufactured are of the insulated type (Torq Transloading 2012). This high percentage is a strong indicator that most of the tank cars on order are either to carry heavy oil sands crude, or to give carriers the flexibility to do so. Crude oil grades that can be transported by pipeline (light crude oils through to heavy crude oils such as dilbit), can generally be transported in standard tank cars (although moving dilbit in cold weather can require insulated cars). The most economical way to transport oil sands crude by rail is not as dilbit (which comprises around 70-75 percent bitumen with 30-25 percent diluent) but rather as either railbit (around 15-20 percent diluent) or as undiluted bitumen (zero diluent). Transporting the bitumen in those forms can save a producer the expense of acquiring diluent, shipping the diluent (mixed with the bitumen to make the dilbit) and also, increasingly, returning the diluent to the oil sands production sites in Alberta for reuse. Railbit and raw bitumen would be transported in rail cars that are insulated and contain steam coils for re-heating the bitumen as necessary at destination. Based on a roughly 60 percent share of the current back-log in tank car orders, there should be enough new insulated rail tank cars available by late 2014 to transport approximately 800,000 bpd of heavy crude oil per day. [42]

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[40] The EnSys 2011 study identified that there is adequate cross-border rail capacity at several crossings from Washington to Michigan to allow for a substantial increase in rail traffic even before any track capacity expansions at those locations are needed. In turn, these crossings act as gateways into the extensive U.S. rail network that leads to essentially any destination, including the West, Gulf, and East Coasts. In addition, Canada itself has a highly developed rail network running both west and east from Alberta and Saskatchewan.

[41] A previous high back-log for rail tank cars occurred in early 2007 following the surge in ethanol use in gasoline under the RFS-2 standard. The back-log peaked at over 35,000 cars but was cleared in around 24 months.

[42] Using the Gulf Coast as a typical destination, with a transit time of around 9 days, each daily loading would require a total of around 20 unit train sets (one loading, nine in transit laden, one off-loading, nine returning empty [or carrying diluent]). Since each unit train comprises around 100 cars, the capacity to move incrementally approximately 200,000 bpd of Western Canadian crude each year would require adding approximately 6,000 rail tank cars per year (each year an additional 3 daily loading × 20 train sets × 100 cars per train). More crude oil could be transported each day if the destination were the Canadian or U.S. West Coast as those journeys are shorter.

The CAPP projections for crude supplied to market are based on produced bitumen being moved either after upgrading to synthetic crude oil (SCO), or as synbit or dilbit blends, with the latter being predominant. Despite the fact that there is a reduction in carrying capacity per car when moving undiluted bitumen,[43] the ability for rail to reduce or eliminate diluent has the potential to decrease the total heavy crude volumes that must be shipped out from Western Canada and (increasingly) returned as diluent. For example, 800,000 bpd of raw bitumen or railbit would be equivalent to just over 1 million bpd of dilbit in terms of the volume of bitumen shipped. In other words, there are enough insulated rail cars that will be delivered by the end of 2014 that could transport a greater volume of oil sands bitumen than the proposed Project.[44]

Insulated and coiled tank cars may have been ordered in support of specific plans to transport heavy crudes, or they may have been ordered to provide the flexibility to transport such crudes in the future but without specific current plans to do so. Also, shippers of WCSB heavy crudes would be in competition with other crude oil shippers relying on rail transport. Even taking those factors into account, it does not appear that the ability to manufacture rail tank cars in sufficient numbers is likely to present logistical constraints beyond the next few years. Because it is expected the rail car manufacturers will be able to clear a large backlog over the next two years, they should be able to keep up with on-going growth requirements at the pace to match WCSB production growth.

The above analysis indicates that in order to prevent shut-in of WCSB heavy crude production, rail capacity, supported by barge and tanker, would only need to continue to increase consistent with the trends already observed. However, if the rate of production is substantially higher than indicated in the CAPP 2012 forecast (and the other forecasts shown in Figure 1.4.4-11), and if there are delays in the delivery of new rail cars and terminals (contrary to the current trends) it is possible that some short-term shut-in of WCSB heavy crude could occur.

For example, if existing rail loading/unloading capacity were not available at the time of a permit denial, and grew at a rate of 200,000 bpd each year beginning in 2014, it would take until the third quarter of 2017 for rail capacity from the WCSB to surpass the capacity provided by the proposed Project. If existing rail loading/unloading capacity were not a limiting factor, another limiting factor could be the ability to manufacture suitable rail cars. If the 28,000 new insulated and coiled rail cars to be delivered by the end of 2014 were not used to transport WCSB crude that would have been transported on the proposed Project, new cars would need to be ordered. If new cars were ordered at the time of a permit denial, at current production rates, it would take until the fourth quarter of 2016 for rail capacity to exceed the capacity of the proposed Project.

[43] Because tank car load limitations are by weight rather than volume, less volume of the more dense raw bitumen can be carried compared to dilbit in any one rail car, and less dilbit can be carried than a light crude. Thus, a rail car carrying high-density undiluted bitumen will only be able to carry around 550 barrels versus 650–700 (or more) for a light crude.

[44] Steam heating would be required at any terminals that receive undiluted or partially diluted bitumen in insulated rail cars. No information to date has indicated that either building terminals or equipping off-loading terminals with steaming capabilities would comprise a major constraint to increased rail shipping of Western Canadian heavy crudes and bitumen.

If one or both of the limiting factors described above were to occur, then WCSB production could be curtailed during that time frame by an average annual rate of 80,000 to 120,000 bpd over three years (2015, 2016, and 2017).[45] After 2017, sufficient rail infrastructure would be in place to accommodate the full capacity of the proposed Project. While such constraints could occur, considering the analysis offered at length within this section, no information has been found that would indicate rail growth in the WCSB could not grow at a similar rate to recent rail growth trends.

Costs of Non-Pipeline Transport

The Final EIS examined the costs of non-pipeline transport options, and noted that, although they were higher than pipeline, they were not likely to be a disincentive to using those transportation options if pipeline capacity was not available. "While the per barrel tariff costs of moving conventional light crude oil by rail or barge are generally higher than those for shipping via pipeline, cost differentials narrow or can even reverse when shipping oil sands. Consequently we do not see cost deterring rail, barge and tanker expansion in any form of "No Expansion" situation . . . Even if transport costs for rail, barge and tanker were appreciably higher, there would still be an overriding incentive to use those modes to avoid production shut-in" (EnSys 2011). Recent developments described above strongly support those observations.

This Supplemental EIS includes an updated estimate of rail costs versus those in the Final EIS from 2011, as described in more detail in Section 2.2, Description of Reasonable Alternatives. There is much more information available about these costs, and the current information indicates the costs are higher than were estimated in 2011.

Estimating the comparative rail costs for transporting the bitumen produced from the oil sands is not as straightforward as it is for conventional crude oils because, as mentioned above, producers can transport the bitumen to market in different forms, either as synthetic crude oil (if it is upgraded), dilbit (diluted bitumen to pipeline specifications, 25–30 percent diluent), railbit (bitumen with 15–20 percent diluent), or raw bitumen (no diluent). Synthetic crude and dilbit can be transported by rail using standard tank cars and using the same off-loading facilities as light crude oils (although the high proportion of insulated rail cars with steam coils in current orders indicates a possible trend by shippers to have these cars available to move dilbit as a safeguard against possible solidification of the crude in adverse weather conditions or in the event of delays). Unlike light crude, synthetic crude and (generally) dilbit, which can use standard cars and off-loading terminals, railbit and raw bitumen need insulated and coiled rail cars, and can only use receiving terminals that have been modified to provide steam to pass through the rail car coils (these modified terminals can also be used to offload the lighter crude grades). As noted above, producers are already transporting bitumen by rail as dilbit, railbit, and raw bitumen.

The updated cost for rail transport of dilbit from the WCSB to the Gulf Coast is estimated, in Section 2.2, Description of Reasonable Alternatives, to be approximately $15.50 per barrel based on unit train economics. CAPP provides an estimated pipeline tariff for the same transport of approximately $8–$9.50 per barrel (see Appendix C, Market Analysis Supplemental

[45] This assumes all rail transport is of dilbit or light crude. If raw bitumen or railbit is transported by rail, the total volume that must be moved by rail is less than that by pipeline. If it were assumed that rather than transporting pipeline quality dilbit (which is 30 percent diluent), the rail shipping of bitumen averaged only 10 percent diluent, then the difference in annual barrels per day shipped (expressed in terms of pipeline dilbit) averaged over 2015, 2016, and 2017 could be from 40,000 to 60,000 bpd.

Information; CAPP 2012).[46] A straight comparison of those respective costs indicates an increased cost of rail transport of \$6–\$7.50 per barrel. However, these two estimated costs are not on the same basis and likely overstate the cost differential because they compare a long-term committed pipeline tariff (i.e. for contracts of 10–20 years) to short-term and/or uncommitted rail prices.[47] An uncommitted pipeline tariff would be approximately \$14.00 per barrel (Appendix C, Market Analysis Supplemental Information). This would reduce the estimated difference in transport costs to \$1.50 per barrel. This like-with-like comparison is potentially more representative of what the pipeline-rail differential could be for both longer term committed/base load movements and shorter term/uncommitted tariff differences, which would reflect "marginal" costs/movements.

The above estimates also do not take account of the savings that a producer can achieve because shipping bitumen by rail can be done with less diluent than shipping it by pipeline. As previously mentioned, using less (or no) diluent enables a producer to save the costs of acquiring diluents, paying the tariff to transport the diluents (as part of dilbit), and, indirectly, having the diluent returned to source (Alberta) for reuse. If diluent is backhauled on the rail cars on the return trip, net transport costs are directly cut.[48] In EnSys 2011, it was estimated that the cost, on a net barrel of bitumen basis, for shipping raw bitumen by rail could be approximately the same as the cost by pipeline. With the updated higher rail transport costs cited above, the estimated net cost of shipping per barrel of bitumen still comes within \$2–3 of the pipeline tariff (less, if the comparison is to the uncommitted pipeline tariffs). The orders for more than 28,000 new insulated rail tank cars provide evidence that industry considers shipping railbit or bitumen to be an economic option, and that it can be employed in large quantities.

It is assumed that the logistics constraints noted in Section 2.2, Description of Reasonable Alternatives, would prevent additional oil sands production from being shipped entirely as raw bitumen or railbit (since moving raw bitumen or railbit requires special loading/off-loading terminals and insulated cars whereas dilbit generally does not). Thus, if rail had to supply all of the additional transport capacity for WCSB production, the incremental barrels would have to move to market as dilbit or synthetic crude oil. It is also assumed that even if adequate pipeline capacity were available, the incremental barrel of production would not be able to take advantage of long-term transport contracts. Thus, not all barrels transported by either pipeline or rail could be expected to obtain the best price for each respective mode of transport.

[46] The \$8 rate is listed in CAPP 2012 as a tariff rate from Hardisty to the Gulf Coast on the Enbridge system. The \$9.50 rate is estimated based on tariff rates for the existing Keystone pipeline to Cushing, Oklahoma, plus the tariff rate on the Seaway pipeline from Cushing to the Gulf Coast. Where relevant, an estimated tariff rate of \$9 is used for the proposed Project, on the assumption that some cost savings would be achieved over the \$9.50 estimate by shipping with one pipeline operator.

[47] The freight rates most commonly quoted for rail shipments are for a spot basis. Indeed, one of the frequently highlighted differences between rail and pipeline for crude oil shipment is that rail, unlike pipeline, does not require shippers to enter into long term contracts. (For crude oil pipeline shippers, these can range from 5 to as long as 20 years.) However, term contracts for moving crude via rail are beginning to appear; for example, one such contract entails a 5 year commitment to ship bitumen (as railbit) by rail from Fort McMurray to Natchez, Mississippi, and thence by barge to Louisiana refineries. Freight rates on term rail contracts are reported to be lower than spot rates, as is the case with pipelines.

[48] Also, producers may get a better price from the refineries by avoiding a price discount incurred for dilbit because it has heavy and light crude fractions with little in the mid-gravity range (Hart Heavy Oil Outlook 2012).

For the purposes of the analysis below it is assumed that the incremental increase in cost of rail compared to pipeline transport is $5 per barrel, which is the middle of the range for the potential difference in cost of $2–$7.50.[49]

The current recession coupled with a fundamental reduction in domestic coal use have negatively affected the revenues and traffic volumes of most North American railroads. Increased demand for rail transportation of crude oil has not only been an important growth area, but the crude oil business has the key characteristics that railroads are targeting. These include: unit train movements from a single origin to a single destination; no need for intermediate handling or investment in yard and terminal facilities; third party or shipper investment in railcars, loading, and unloading facilities; large volumes moving over the long term; and ample margins . As a result, the carriers have and will continue to invest in the infrastructure required to handle increased crude oil volumes.

Current rail prices for crude oil reflect limited competition among the carriers; but prices are high enough to generate attractive margins that justify long term capital investment. Over the long term, rail pricing will likely fluctuate to reflect changes in both the price of oil and the margins available in the petroleum business. When oil prices increase, the carriers will attempt to capture a portion of the increase in the net rents available through rail rate increases. But these increases will be tempered by their competing goal of continuing to encourage volume growth.

In sum, the rail carriers would be expected to invest the capital required to support increased crude oil shipments, and set prices at levels that will encourage volumes sufficient to provide sustained returns on these long term investments.

Oil Sands Breakeven Costs

To assess the potential impact of increased transport costs on crude oil production in the oil sands, the Department reviewed information regarding breakeven costs for different types of oil sands project. The "breakeven cost" is often expressed as the lowest price of a selected marker crude that is necessary to enable a potential production project to cover all its costs and earn a commercial rate of return on capital employed—typically 10–15 percent (NEB 2011). A long-term increase in transport cost to take crude oil to market from potential extraction projects acts as an increase in the breakeven costs for those projects.

In the oil sands, breakeven costs vary according to the type of extraction project, as well as the business plan of the producer in terms of whether to upgrade the bitumen to synthetic crude oil. The Canadian NEB in 2011 provided estimated breakeven costs for new oil sands projects. Those prices expressed in terms of WTI price in 2011 dollars were: $51–61 per barrel for new in-situ crude; $66–76 per barrel for mining (without upgrader); and $86–96 per barrel for mining (with upgrading) (NEB 2011).[50] If an estimated incremental cost for rail compared to pipeline of

[49] Despite estimates for larger differences in price, $5 was selected for this analysis in part because if no pipelines are available then larger producers would utilize rail delivery options and it would be expected that they would get better prices than the most expensive rail estimates, and because of the opportunity for at least some portion of producers to take advantage shipping railbit or raw bitumen.

[50] Break-even costs for oil sands projects are expressed in terms of WTI, but the crude oil produced from all of the projects, save for the mining with upgraders, is a heavy crude oil that is sold at a discount from WTI. The benchmark for the Canadian heavy crude is WCS. Estimates for the breakeven oil cost for the crude oil in the Bakken range from approximately $55 to $70 per barrel for WTI (Gebrekidan 2012).

$5 per barrel is applied to the above cost estimates, then the total range of oil sands projects breakeven costs becomes WTI $56–$101 per barrel as summarized in Table 1.4-10.[51]

Table 1.4-10 Economic Threshold for New Oil Sands Projects

	WTI Price Dollars per Barrel[a]	
	NEB 2011	**NEB + Rail Cost**
New In Situ	$51– $61	$56–$66
New Mining and Extraction Only (No Upgrading)	$66–$76	$71–$81
New Mining, Extraction, and Upgrading	$86–$96	$91–$101

Source: NEB 2011.

[a] In 2011 dollars.

The AEO 2013 outlook projects both Brent and WTI crude oil prices (in constant 2011 dollars) above the band of breakeven costs for in situ and for mining without upgrading for all years through 2040. For new mining-plus-upgrading projects, these crude oil prices are within the band of breakeven costs ($91–$101) through approximately 2018, then move well above the breakeven costs (Figure 1.4.6-8).[52] At approximately $120 to $145, the WEO Current Policies Scenario oil price is above the breakeven costs for all projects from 2015 through 2035. NEB 2011 noted that the oil price in its reference case (U.S. $90/barrel (bbl) in 2011, rising to $115 in 2035) is "sufficient to promote active growth in oil sands capacity." While lower than the other projected prices, the NEB price is high enough to support in situ and mining (no upgrading) projects and is above the mining with upgrading breakeven costs by 2019.

The graph does indicate that, particularly in the shorter term, the most expensive oil sands projects—new mining project with upgraders—are economically challenged. This is consistent with the NEB 2011 report.[53] Decisions on whether to proceed with those types of projects could be impacted by an increase in transportation costs.

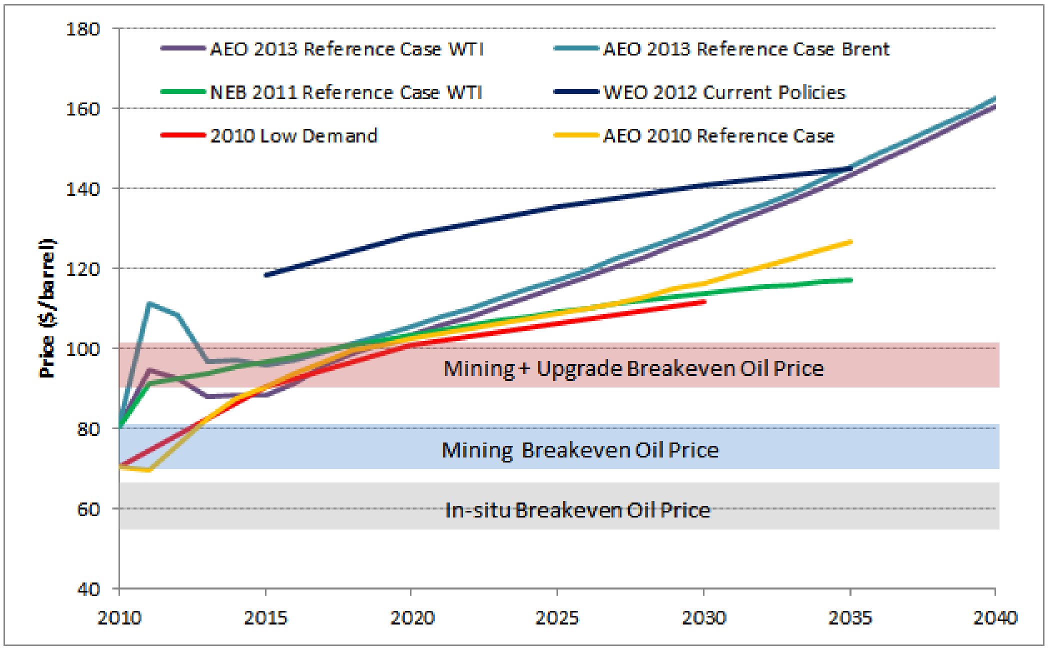
It does not appear, however, that there are any new mining plus upgrading projects included in the CAPP 2012 projections, although there are expansions of existing mining plus upgrading projects, and new or expanded stand-alone upgraders.[54] Thus, most of the increased production in the CAPP projection is expected to come from the types of oil sands projects with adjusted NEB estimated breakeven costs of $76 or below. The implication is that a $5 (or more) per barrel increase in breakeven cost through a shift to rail transport would have little impact on WCSB oil sands projects on the basis of EIA and IEA crude price projections.

[51] These cost estimates do not include a projection in how costs of production projects may change over time. Factors that would decrease costs compared to the NEB estimates are improving technology (which NEB noted could reduce costs by 1.5 percent per year) and an outlook for natural gas prices lower than the NEB used. Conversely, shortages in labor and supplies in the oil sands region driven by significant expansion in extraction projects could increase production costs.

[52] The AEO 2013 includes an outlook for Brent and WTI prices, but does not include outlooks for low and high oil price scenarios because it is the early release version. Alternate cases and scenarios from the various outlooks are discussed in this section.

[53] The NEB Report noted that because in the period between 2008–2010 the differential between light and heavy crudes had been relatively narrow, and was expected to remain narrow for the near to medium term, this, along with the high capital costs of constructing upgraders, is not supportive of constructing new upgrading facilities NEB (2011).

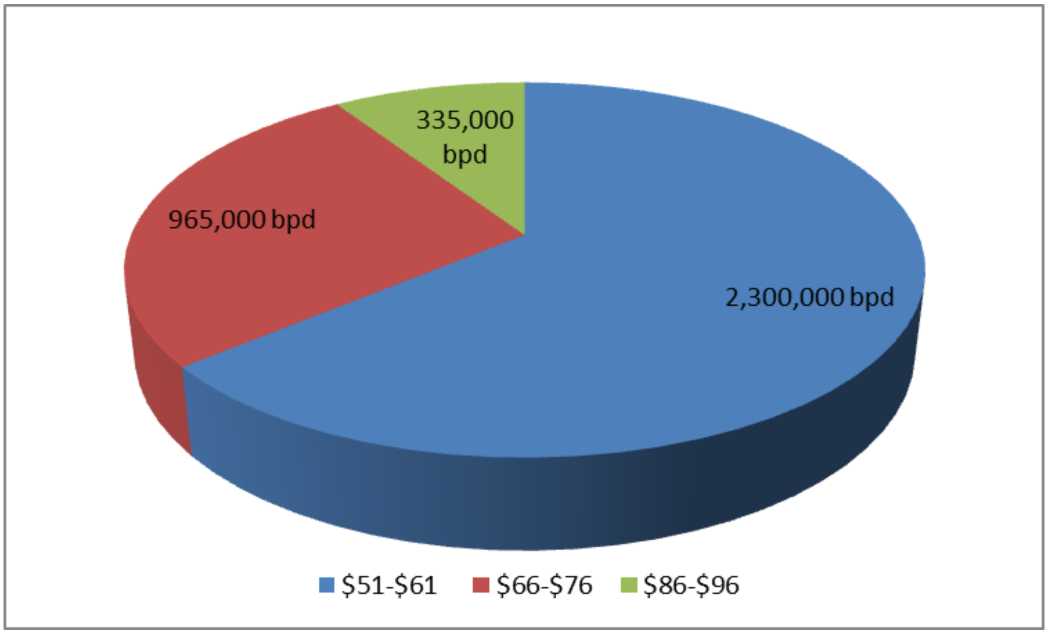
[54] The 2012CAPP Growth Outlook has SCO supply to market rising from 804,000 bpd in 2012 to 983,000 bpd in 2015 but thereafter remaining in the 1.0–1.15 million bpd range through 2030.



Source: EIA 2013, EIA 2010, EnSys 2010, NEB 2011, IEA 2012c.

Figure 1.4.6-8 Comparison of Crude Oil Prices (2011 dollars) To Oil Sands Breakeven Costs Including Cost of Rail Transport

The CAPP 2012 outlook estimates that by 2030 oil sands raw bitumen production will increase to 5.3 million bpd, up from 1.7 million in 2011. Of that increase, 2.3 million bpd comes from in-situ projects (64 percent) and 1.3 million bpd comes from mining projects (36 percent). That outlook does not break out the estimates between mining projects with and without upgraders. The 2012 Hart Heavy Oil Outlook, which had a slightly higher estimate of oil sands production (and an outlook period to 2035), does not include any new mining projects with upgraders in its estimate, but does have approximately 335,000 bpd coming from expansions to existing mining projects with upgraders. This is consistent with the CAPP projection of SCO supply rising from just over 800,000 bpd in 2012 to the 1–1.15 mmbpd range from 2016 on. On the basis that the expansions of the mining with upgrading projects in the Heavy Oil Outlook are included in the CAPP figures for mining, then the outlook for the increases in production in each range of breakeven costs is approximately: 2.3 million bpd by 2030 in the $51–$61 breakeven range; approximately 965,000 bpd in the $66–$76 range; and approximately 335,000 bpd in the $86–$96 range (Figure 1.4.6-9).



Sources: CAPP 2012, Hart 2012b

Figure 1.4.6-9 Estimated Additional Production in Oil Sands Raw Bitumen (bpd by 2030) by Project Break-Even Cost

Compared to industry analysis in 2012, this may slightly underestimate the potential volume of oil sands production that could be brought to market from projects with breakeven costs under $70 per barrel. As noted above, in the CAPP forecast there would be approximately 1 million bpd of additional raw bitumen production by 2020 (and 2.3 million bpd by 2030) with breakeven costs below $70. However, the referenced industry analysis examined all announced oil sands projects (which would result in production of an additional 3.4 million bpd by 2020 if they all went forward) and estimated that by 2020 there are 2.4 million bpd of those projects with breakeven costs below $70 per barrel (CIBC 2012). Therefore, if all announced projects in the industry analysis went forward, then the production level would already by 2020 slightly exceed the 2030 level forecasted by CAPP. That industry analysis also estimated that there is 1 million bpd of potential additional production by 2020 with breakeven costs in the $70–100 per barrel range.

There has been a general trend in the outlook for oil sands production away from upgrading bitumen in recent years.[55] The 2008 and 2012 CAPP forecasts each had similar total volume of oil sands crude oil coming to market by 2020, approximately 3.8 million bpd. There was a significant difference in the projected percentage of that crude oil that would go to market as upgraded synthetic crude oil, 47 percent in the 2008 forecast, dropping to 28 percent in the

[55] There has also been a trend away from mining projects and towards in-situ projects. The 2006 forecast had in-situ production decreasing from a projected 53 percent of oil sands production in 2010 to 43 percent by 2020. In contrast, the 2012 forecast showed actual in-situ production in 2010 being 50 percent, increasing to 58 percent by 2020 and 62 percent by 2030.

2012 forecast.[56] Any continuation of this trend would mean that even the limited number of planned upgrading projects integrated with mining may not go ahead, thereby eliminating or delaying construction of just the "high breakeven cost" upgrading portion of the project but without any reduction in overall oil sands output. The associated oil sands production would be sent to market as bitumen, potentially diluted depending on the transport mode.

Although it appears that most oil sands projects in the CAPP forecast (and the CIBC report) likely have breakeven costs low enough that the incremental increase in transportation costs would not drive project costs above the breakeven costs at expected oil prices, that does not mean that oil sands production would be completely insensitive to changes in costs (or the outlook in oil prices). To assess the potential impacts of a change in costs of production (or change in price of oil) on the rate of production, the next section examines the most recent International Energy Outlook (IEO)[57] from the EIA, as well as the previously mentioned analyses of oil sands project breakeven costs, as well as other sources.

The IEO includes three price cases for the outlook for oil prices, a high price case, the reference case, and a low price case. Total oil sands production is one of the outputs in each price case. Correlating the change in oil sands production amounts with the change in price in those cases gives some sense of the potential sensitivity of future production to incremental changes in oil price. A change in oil price can be considered equivalent to a change in costs in that both impact netbacks (profits) to the producer. In this sense, a decrease in oil price of $1 has an equivalent impact on a producer of an increase in production cost of $1. Both result in $1 less in netback and would be expected to have a similar impact on production.

In the IEO 2011 (the most recent version published), the reference case oil price was approximately $108 in 2020, growing to $125 by 2035. The low oil price case had oil prices dropping to approximately $50 throughout the projection period to 2035. The difference in oil sands production between those two cases was approximately 500,000 bpd in 2020, increasing to 1.3 million bpd in 2030, and to 1.7 million bpd in 2035. Assuming a linear relationship between oil price and amount of production,[58] then for every $5 change in oil price, the change in production would be approximately 40,000 bpd in 2020, 90,000 bpd in 2030, and 120,000 bpd in 2035.

It is unlikely that the relationship between these two variables is linear throughout the full $50 to $125 price range. One would expect a larger impact on production amounts when oil prices are below $100, and thus within the range of breakeven costs of the oil sands projects. To assess the potential difference in impacts in different price ranges, two studies were analyzed in addition to the IEO: the CAPP projections (combined with NEB cost estimates) and the CIBC report. According to the analysis above, it is assumed that a $30 reduction in oil price (a decrease from $100 to $70) would result in all projects with breakeven cost above $70 being delayed/canceled. It is assumed that within the $70 to $100 price range, there is a linear relationship between change in oil price and change in production amount.

[56] In 2006 the forecast was that approximately 55 percent of the oil sands crude oil coming to market in 2020 would do so in the form of upgraded synthetic crude oil (either transported as synthetic crude oil itself, or used to dilute bitumen to form a synbit).
[57] The EIA's AEO reports do not include oil sands production as one of their outputs, but the EIA's IEO do.
[58] A linear relationship means that every dollar in oil price change will result in the same amount of change in production.

Table 1.4-11 presents estimates of potential impacts on oil sands production per $5 change in netback to oil sands producers (e.g. either a $5 change in oil price or a $5 change in production/delivery costs) according to the three different reports mentioned above. The range of potential changes in production is from 40,000 to 210,000 bpd depending on the study, the time horizon, and the range of world oil price. The table also presents those changes in volume as a percentage change in total oil sands production in each respective outlook.

Table 1.4-11 Estimated Potential Change in Oil Sands Production per $5 Increase in Cost per barrel of Oil in Different Outlooks[a,b]

	2020		2030	
	Production Change (bpd)	% of Total Production	Production Change (bpd)	% of Total Production
IEO 2011 (Oil Price $50–$125)	40,000	1.3%	90,000	2.1%
NEB/CAPP (Oil Price $70–$100)	105,000	3.1%	210,000	4.0%
CIBC (Oil Price $70–$100)	170,000	3.3%	NA[d]	NA

Source: NEB 2011, CAPP 2012, CIBC 2012, Hart 2012b.

[a] The IEO assumes a linear relationship between price and production amount where oil prices are between $50 and $125 per barrel, the NEB and CIBC numbers assume a linear relationship between those variables when crude prices are between $70 and $100.
[b] In 2011 dollars.
[c] The IEO outlook extends to 2035. In 2035, the production change would be 120,000 bpd, which would be 2.4% of the total IEO forecasted production for the oil sands.
[d] NA = not applicable.

This range of potential changes in production is consistent with the modeling undertaken by Brookhaven National Laboratory to produce the 2010 Low Demand Outlook for the EnSys 2010 study. There, the Low Demand Outlook in 2030 (when compared to AEO 2010) resulted in a decrease of $5 in world oil price with a corresponding decrease of 170,000 bpd in oil sands production.

As discussed above, the incremental cost of transporting a barrel of crude oil to the Gulf Coast by rail versus pipeline is between approximately $2 and $7.50. It is most likely that if all incremental production in the oil sands had to be carried by rail, that production would be shipped in a variety of forms (raw bitumen, railbit, dilbit, and SCO) and under a variety of terms (long-term committed, to uncommitted) that would result in different incremental costs. If it were assumed that the incremental cost of transport for all additional barrels were only $2 more than pipeline, then the change in production could be less than half that indicated in Table 1.4-11 (36,000–84,000 bpd in 2030). On the other hand, if it were assumed that the incremental cost of all additional barrels were $7.50 more than pipeline, the change in production could be approximately 50 percent higher (from 135,000 to 315,000 bpd in 2030).

These potential changes in production volume would not necessarily result just from a decision on any single infrastructure project, including the proposed Project. Rather, the above analysis of the potential changes is an indication of the scope of impact on rate of production if all pipeline projects did not go forward, and the industry had to absorb the additional costs of non-pipeline transport options across all incremental production. If only a small marginal volume of oil sands production had to be shipped at higher cost, it would only be that small marginal volume that would suffer the reduced netback and whose production could be affected. All other projects that were moving their production via lower cost pipeline would achieve the higher netback and their production would not be impacted. In that sense, a decision on the proposed Project alone likely would not impact the market enough over the medium to long-term to result in changes in production at the scale indicated in Table 1.4-11. If the estimates of percentage changes in production per dollar change in oil price/netback indicated in Table 1.4-11 were applied to the volume of crude oil that could be shipped by the proposed Project rather than the total volume of forecasted increased production (i.e., if the 830,000 bpd capacity of the proposed Project had to be shipped by rail and other means with an average increase in transport cost of $5 per barrel), then the implied potential change in production could be from 20,000 to 30,000 bpd in 2030 (from 0.4 to 0.6 percent of total WCSB production).[59]

As discussed in Section 2.2, Description of Reasonable Alternatives, and as was set out in EnSys 2011, a range of listed pipeline projects exists and others are likely to be forthcoming over time. If even one of the pipeline projects went forward, but all other projects did not proceed, the logistical challenge of having rail transport all growth in production would be reduced.[60] Nonetheless, the environmental analysis in this Supplemental EIS takes account of the possible impact on the rate of production in the oil sands, where relevant.

Incentives to Use Rail and Other Non-Pipeline Transport

When there are constraints on pipeline capacity to transport crude oil from the production area to market (or from a particular crude oil hub to market), one of the impacts is a local supply glut, which puts downward pressure on the price of crude oil in that area. Such a situation is currently occurring with respect not only to crude oils produced in the WCSB, but to much of the inland crude oil production in North America. As noted above, much of the recent rapid increase in production is in areas such as the Bakken, Eagle Ford, Niobrara, Permian, and others that either do not yet have adequate pipeline capacity, or where the crudes from those areas are being delivered into the Cushing, Oklahoma, hub that has not had adequate outbound pipeline capacity, especially southward.[61]

Until late 2010, WTI and Brent crude oil prices moved in parallel with only small differentials between them. Beginning in early 2011, that situation changed. Growth in domestic U.S. and Western Canadian production put pressure on a crude logistics system that was designed to take crude oils to the central United States rather than out to the coasts. This in turn has led to discounted prices for WTI and all inland U.S. and Canadian crudes (nearly all of which are priced off WTI). The discounting has persisted into 2013 and is expected to continue unless and

[59] As noted elsewhere in the Supplemental EIS, the near-term initial throughput of the proposed Project is projected to be 830,000 barrels of crude per day with 100,000 bpd supplied by Bakken crude production and the remaining 730,000 bpd supplied by the WCSB oil sands. However, this estimate assumes that the full 830,000 bpd pipeline capacity is used to transport only WCSB crude, resulting in a slightly greater reduction in WCSB production.

[60] Furthermore, this assessment of the potential production impacts that could arise from the differential between rail and pipeline transport costs was based on present day uncommitted tariffs for each mode. As rail became more established, it could become more efficient. Such a trend, together with increased incidence of longer term contracts, would tend to push rail tariffs down. Conversely, it is possible that, over time, pipeline operators may be successful in moving tariffs up, given the presence of higher cost rail tariffs. The recent approval by the Federal Energy Regulatory Commission for a shift from cost-based rates to much higher market-based rates on the Pegasus pipeline from Patoka, Illinois, to the Gulf Coast arguably reflects pipeline versus pipeline competition but is, nonetheless, a possible indicator that such a trend could occur in the event of extensive pipeline versus rail competition. In short, the effect of these trends could be to narrow the gap over time between the costs of rail and pipeline transport.

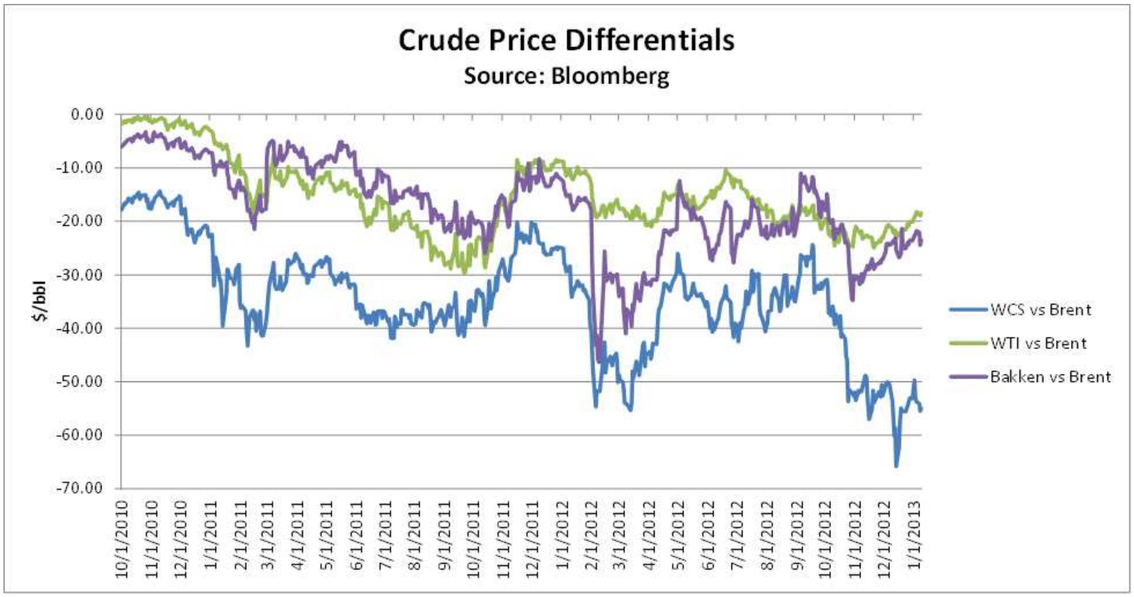
[61] Even with the additional pipeline capacity slated to come on line, AEO 2013 (EIA 2013b) continues to have inland crude oil at a discount compared to coastal crude (Figure 1.4.3-6).

until adequate capacity becomes available to enable crudes to move to U.S. and Canadian coastal markets. The continued growth in crude supply in both the United States and Canada has led to a race to move crude by whatever means available to coastal markets. As a result, the logistics system is adapting, with changes in pipeline, rail, and to some degree marine infrastructure.

Recent trends for transportation of Bakken crude are illustrative. Bakken discounts versus Brent initially followed those for WTI. In early 2012, Bakken discounts steepened severely but have since recovered. Arguably, this recovery has occurred because of the strong growth in rail movements out of the Bakken, especially during the second half of 2012. By the end of 2012, rail takeaway capacity from the North Dakota part of the Bakken was in excess of 700,000 bpd. Rail movements out of North Dakota were reported as reaching almost 500,000 bpd, indicating an average load terminal utilization of around 65 percent. While rail takeaway capacity is projected by the North Dakota Pipeline Authority to grow to over 900,000 bpd by the end of 2013, the North Dakota Pipeline Authority also sees pipeline takeaway capacity plus crude oil consumption at a refinery in North Dakota growing to over 750,000 bpd by end 2013 and to over 1.2 million bpd by 2015, excluding Keystone XL.

There are, however, notable differences between the two sets of capacity. The bulk of the pipeline expansions are designed to move Bakken crude either north or east into the Enbridge Mainline system (or possibly the existing Keystone Mainline). Thus, these expansions do not directly move the Bakken crude out of the Midwest (PADD 2). Rather, they are reliant on expansions to additional lines, generally either south to the Gulf Coast or east to eastern PADD 2 and eastern Canada to move the Bakken crude to additional markets. In contrast, the rail takeaway systems have been set up primarily to move Bakken crude directly to coastal markets. Only one new unit train terminal has been built inland with access to Cushing: the terminal at Stroud, Oklahoma. Conversely, unit train off-loading capacity on the Gulf Coast is estimated to be more than 600,000 bpd by early 2013. This encompasses capacity for both light and heavy crudes. Gulf Coast off-loading capacity is projected to be exceeded, however, by the U.S. East Coast off-loading capacity. Off-loading capacity on the U.S. East Coast was minimal in early 2012, but is projected to reach over 800,000 bpd by the end of 2013. Moreover, an additional 70,000 bpd of off-loading capacity is available in New Brunswick, Canada. Finally, rail off-loading capacity in Washington and California is expected to reach 135,000 bpd during 2013.

What this capacity means for the Bakken is significant. The bulk of the movements to the East and West Coasts are for light, i.e., predominantly Bakken crude, which will be priced against Brent and other international market crudes. These developments should help limit Bakken discounts to potentially the \$10–\$20 per barrel range, possibly less, as represented by the difference in freight costs between moving a Brent or West African type crude from the North Sea/West Africa to, for example, Philadelphia, versus moving Bakken crude from North Dakota (or more technically from Clearbrook, Minnesota, which is the location for setting Bakken crude pricing) to that same destination (Figure 1.4.6-10). Thus, rail out of the Bakken is having the effect of enabling Bakken crudes to avoid the Cushing pipeline bottleneck and realize pricing based off international marker crudes.



Source: Bloomberg 2013b.

Figure 1.4.6-10 Crude Oil Price Differentials Compared to Brent

In contrast to the recent trend for Bakken crude, discounts for the marker heavy grade WCS have been growing in recent months. Prior to the advent of current logistics constrains, WCS discounts versus Brent were generally of the order of $15–$20/barrel, (primarily reflecting differences in refining values of the two crudes[62]). These discounts deepened to the $30–$40 per barrel range in 2011 and through much of 2012. Recently, the discount widened further to the $50–$60 per barrel range. There is sufficient pipeline capacity today to take Western Canadian crudes cross-border into the central United States, but the severe pricing discounts indicate these crudes are not able to move further and access coastal markets, notably in the Gulf Coast where their value would match that of heavy Venezuelan crudes and Mexican crudes such as Mayan.

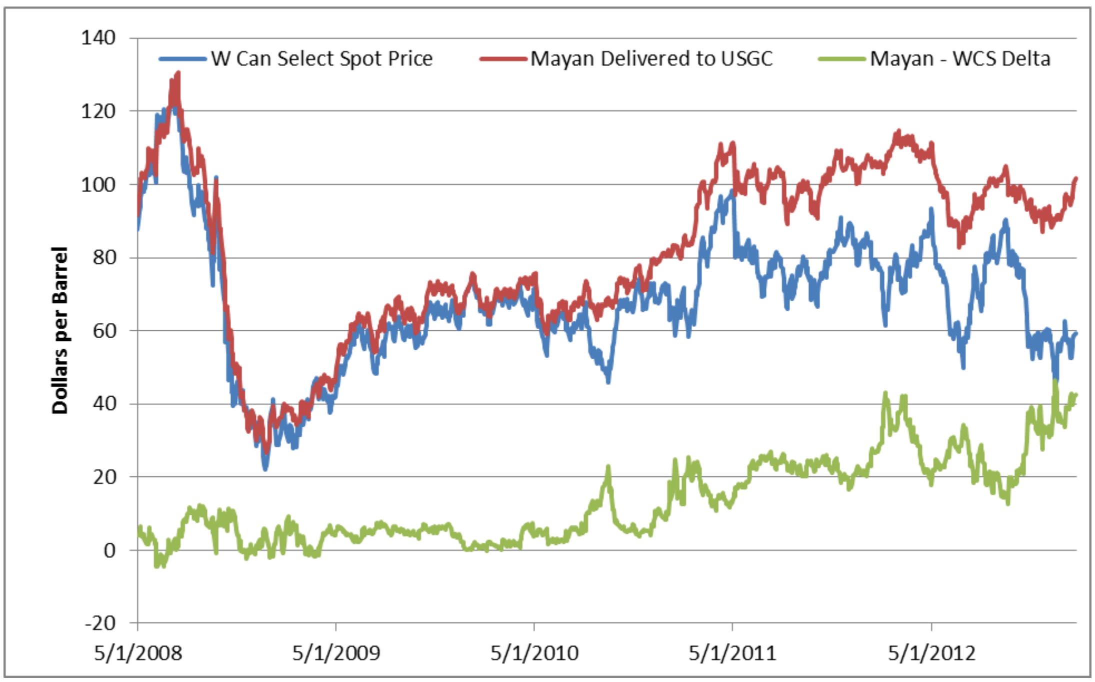
Proposed pipeline projects such as the Enbridge Flanagan South expansion from Chicago to Cushing, as well as the two-stage expansion of the reversed Seaway line from Cushing to the Gulf Coast, would add more capacity to move Western Canadian production to the Gulf Coast. However, the Western Canadian crudes traveling on pipeline will have to compete for space with growing production from the Bakken and Midcontinent, much of which is feeding into the Cushing hub. This competition is made more acute based on the projections outlined above that foresee Western Canadian production growing at an average of approximately 210,000 bpd per year through 2020.

These steep crude discounts are a disincentive to producers to proceed with new extraction projects. In particular, they put pressure on the more economically marginal extraction projects.

[62] Producing sufficient quantities of high-value products such as gasoline and low sulfur diesel from a heavy sour crude requires the installation of additional processing units at a refinery. As explained in section 1.4.4, Market Developments Since the 2011 Final EIS, the installation of these units requires significant capital investment and higher operating expenses. The heavy crudes are discounted from lighter crudes to reflect this increased refining expense.

Recent commentary has suggested that if the current prices persist some conventional heavy production may be idled, but also noted that larger operating in-situ projects in the oil sands likely could sustain even lower prices (below $30 per barrel) before considering idling (Reuters 2013b). Also, Suncor, one of the largest oil sands producers, has noted that it was taking a write down on an upgrader project, and was delaying a decision on proceeding with two new mining projects (as well as an upgrading project) because of concerns about rising costs for the projects and oil prices. Canadian Natural Resources cut its capital spending in 2012, primarily related to expansions at one of its mining projects. On the other hand, even at the current depressed oil prices in the WCSB, both of those companies are planning 10 percent increases in their capital spending in 2013 (RBC Economics 2013).

At the same time these steep discounts in the prices of oil sands crudes (and other inland crudes) also create a significant incentive for refiners to obtain those crudes.[63] The discounts mean that, even taking into account the additional cost of non-pipeline transportation options such as rail, a refiner can obtain the inland crudes at a discount to the global prices they pay for water born crudes. Figure 1.4.6-11 shows the WCS discount to Gulf Coast heavy crude prices (Mexican Mayan) leaves significant room for accommodating increased transport costs and still making a profit by transporting the crude oil to the Gulf.



Source: Bloomberg 2013b

Figure 1.4.6-11 Western Canadian Select Spot and Mayan U.S. Gulf Coast Prices

[63] "The price of Canadian oil exports is low relative to international benchmarks because of infrastructure limitations that prevent oil from getting to market. The larger the price difference grows, the more incentive there is to add infrastructure to get product into regions that earn a higher return (i.e. the more incentive there is to develop further infrastructure" (RBC Economics 2013).

If the producer ships the crude oil to the Gulf Coast (or East or West Coast), that producer can achieve better netbacks than it would by selling the crude into the discounted WCS market in Alberta. If a refiner pays to ship the crude to the Gulf Coast, the cost difference between the delivered WCS and equivalent waterborne international crude represents a substantial cost savings. Or a midstream company may take possession of the crude and pay the shipping costs, keeping the difference in price as profit. This phenomenon is what is driving East Coast refiners and producers in the Bakken to execute medium-term (5-year) contracts to deliver crude by rail, despite an estimated rail cost of $10.50 to $13.75 per barrel. At the current WCS discounts (compared to a comparable heavy crude oil on the U.S. Gulf Coast), a producer/shipper/refiner could absorb the additional rail cost (paying a short-term rate compared to a long-term pipeline rate) and still net over $26 per barrel. These exceptional economic incentives are what is driving the move to transport increasing volumes of crude oil by rail to the coasts when pipeline capacity is not available (see Table 1.4-12 below).

Table 1.4-12 Delivered Costs of WCSB Heavy Crude Compared to Maya Crude

	Crude Cost/bbl	Transport Cost/bbl	Total Texas Gulf Coast Landed Cost/bbl	WCS U.S. Gulf Coast vs. Maya Landed/bbl
Pipeline—WCS U.S. Gulf Coast	58.75	$9.75[a]	68.50	-32.25
Rail—WCS U.S. Gulf Coast	58.75	$15.50[b]	74.25	-26.25
Mexican Maya to U.S. Gulf Coast	NA	NA	100.50	NA

[a]Long-term committed tariff
[b]Short-term rail rate includes fees for loading and unloading tank car and railcar lease.

Over time, as additional transport capacity is brought on line, the price discounts for inland crudes compared to coastal crudes would be expected to narrow. If there are no transport constraints, these would tend to narrow to the point where they reflect the transportation costs for moving the inland crude to the coastal market, plus any quality differences versus the corresponding open market crude used for pricing. As noted above, it is expected that the inland crude discounts could persist for several years as the logistics system continues to adjust and catch up to the new production patterns throughout North America.

1.4.7 Additional Issues in Market Outlook

As with all projections of these types, there is uncertainty as to what will in fact happen. Among the uncertainties identified in the various forecasts examined in preparing this assessment are the following:

Economic growth. The forecasts make certain assumptions about general economic growth, in particular regions and throughout the world. In general, the relatively high forecasted world oil prices are driven by increased demand attendant to economic growth in developing countries led by those in Asia. A long period of global recession could result in lower demand growth and lower oil prices as could a significant increase in potential supply.

Price of crude oil. There is significant volatility in day to day crude oil prices and uncertainty over their long-term direction. Projects to extract oil sands crude are long-term investments and producers generally focus on long-term projections of oil price when making business decisions rather than short-term fluctuations in oil price. The reports examined generally provide different scenarios to account for higher or lower crude oil prices and how those fluctuations might impact the projections.

Technological advances. Technological advances can impact both the supply and demand sides of the petroleum market. On the supply side, technological advances have made it possible for substantial increases in light tight oil production in the United States. As a result of these technological increases, the United States is projected to increase crude oil production by more than 3 mmbpd. Similarly, because the development of light tight oil wells is new, there is uncertainty surrounding their depletion rate, which is a key input in the projections of crude oil production volumes. Similarly, oil sands technology developments are occurring that could over time improve their economics, resource consumption, and greenhouse gas profile. On the demand side, technological advancements in areas such as battery storage or biofuels development could reduce the demand for petroleum based transportation fuels.

Costs of production. Costs of production can be related to each of the above uncertainty factors. Production cost is a potentially significant factor for development of the oil sands as the more expensive oil sands projects are among the most expensive extraction projects globally. Shifts in costs, possibly driven by an increased rate of inflation in the WCSB area as more producers compete for labor and supplies, could impact the economic viability of future projects. On the other hand, improvements in extraction technology, such as the addition of solvents to the in-situ extraction projects, could drive cost savings.

To assess how some of those uncertainties might impact the projected growth in production for both oil sands and light tight oil, the Department examined the different scenarios in recent IEA WEO reports (IEA 2010, 2011, and 2012), the AEO (EIA 2010, 2011, and 2012c), the NEB (2011), and industry commentary and analysis. The different scenarios examined in those reports (whether the scenario is one with a low or high oil price, and whether it assumes more aggressive climate change policies) can have a substantial impact on the projected rates of extraction from the oil sands over the next two decades. However, in all of the scenarios examined, production from the oil sands is expected to increase substantially over current levels.

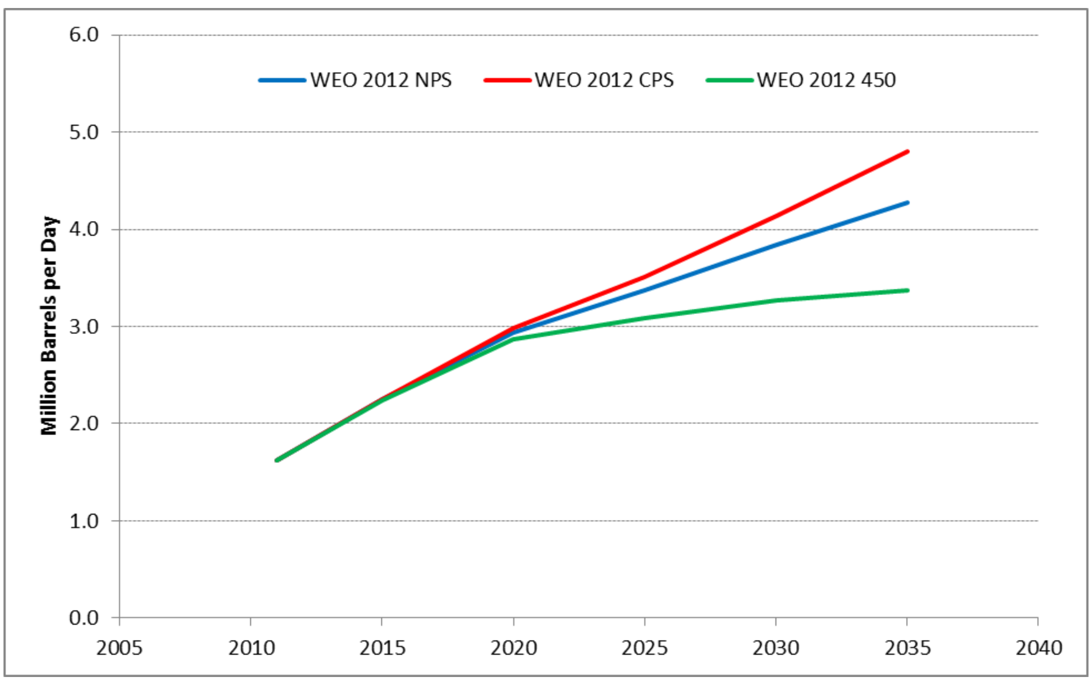
The AEO includes low and high oil price scenarios in addition to a reference case in its projections. In the AEO 2010 and 2011[64], the low oil price case resulted in a slower rate of growth for oil sands production compared to the reference case or the high oil price case . In the 2011 AEO, that production was forecasted to grow from 2010 to 2035 from its initial level of 1.9 mmbpd to 3.23 mmbpd in the low oil price case, to 5.3 mmbpd in the reference case, and to 7.1 mmbpd in the high oil price case.[65] In the AEO 2012 low oil price case, however, the EIA adjusted its assumption about the relationship between a lower oil price and the cost of production for oil sands crude. In the 2010 and 2011 outlooks, the assumption had been that oil sands costs of production were not sensitive to lower crude oil prices in the low oil price case.

[64] Both the AEO 2010 and 2011 low oil price cases included long-term oil prices around $50-$60 per barrel rather than $100+ per barrel in the reference case.

[65] Comparing the AEO 2011 "Unconventional Production North America: Other" to the IEO 2011, which reports oil sands volumes, indicates the AEO category may be 90 percent or more oil sands.

In the 2012 AEO low price case, the EIA assumed that lower oil prices could result in lower costs for steel, cement, and other equipment necessary to produce unconventional resources, including oil sands. This resulted in the low oil price case for 2012 having a higher growth rate in North American unconventional production through 2035 compared to the reference case.

The IEA WEO reports evaluated global policies related to energy use and climate change. Three main scenarios were examined. The Current Policies Scenario assumes no change from policies currently in effect when the WEO is produced. The New Policies Scenario (which the WEO uses as its reference case) assumes policy commitments regarding climate change mitigation and energy use that countries have made, but not yet implemented, will go forward in a reasonable time. The 450 Scenario assumes policy action consistent with limiting long-term global temperature increase to 2 degrees Celsius. As with the AEO's different oil price cases, the different policy scenarios do show different trajectories for oil sands development, but all of the scenarios have significant increases in oil sands production from now to 2035. For example, in the 450 scenario the production from the oil sands is projected to increase from 1.6 million bpd in 2011 to 3.3 mmbpd by 2035.[66] This is a significantly lower growth rate than the Current Policies scenario (which has oil sands production at 4.8 million bpd by 2035), or the New Policies scenario, (4.3 million bpd by 2035), but is a growth rate that would still require additional transport capacity between now and 2020 (IEA 2012) (Figure 1.4.7-1).



Source: IEA 2012.

Figure 1.4.7-1 Comparison of WEO 2012 Projection Scenarios

[66] The 450 scenario assumes aggressive development and deployment of mitigation measures, such as carbon capture and storage, to mitigate greenhouse gas emissions. The WEO indicates that to be consistent with a 450 scenario, even the reduced production amount indicated above (as compared to the Current Policies Scenario) would need to be complemented with deployment of mitigation measures such as carbon capture and storage.

An additional potential impact not examined in detail above, but addressed in the EnSys 2010 and 2011 reports, is the potential for pipeline developments to impact the disposition of WCSB crude oils. As noted in the EnSys reports, as well as in the updated cost estimates in Section 2.2, Description of Reasonable Alternatives, of this Supplement EIS, the transport cost from the WCSB to Asia via the West Coast of North America is significantly less than the costs from the WCSB to the U.S. Gulf Coast. The EnSys 2010 results indicated that because of this cost advantage and the growing demand for petroleum in Asia, if transport capacity was available to the Canadian West Coast, producers would export crude oil to Asia instead of exporting to the U.S. Gulf Coast. This finding has since been reinforced by the high degree of over-subscription that has been occurring on the Trans Mountain Pipeline Expansion Project from Alberta to Vancouver. Its operator, Kinder Morgan Canada, has progressively revised upward its planned expanded capacity for the line. The company's latest announcement, in January 2013, lists a planned expansion from the current 300,000 bpd to 890,000 bpd based on committed shipper volumes of 700,000 bpd (Trans Mountain 2013). This is an increase over the expansion to 750,000 bpd Kinder Morgan proposed in April 2012 and reflects additional shipper support based on a successful supplemental open season. It is a strong indicator of interest in taking WCSB crude oils west. In addition, Enbridge continues to pursue its Northern Gateway project which would comprise a wholly new line to Kitimat on the British Columbia coast with initial capacity of 525,000 bpd, expandable to 800,000 bpd.

As noted above, both of these proposed pipeline projects to Canada's West Coast face significant resistance and uncertainty, but there are strong cost advantages when compared with moving WCSB crude to the Gulf Coast even if rail were used to access the Canadian West Coast (this is further discussed Section 2.2, Description of Reasonable Alternatives). In fact, using rail and tanker to ship crude oil from the WCSB via the West Coast to China is comparable to the pipeline rate to reach the U.S. Gulf Coast. An increase in the transport costs to the Gulf Coast (utilizing alternative transport options such as rail) would have a tendency to increase the economic incentive to utilize any West Coast export options, if they are available.

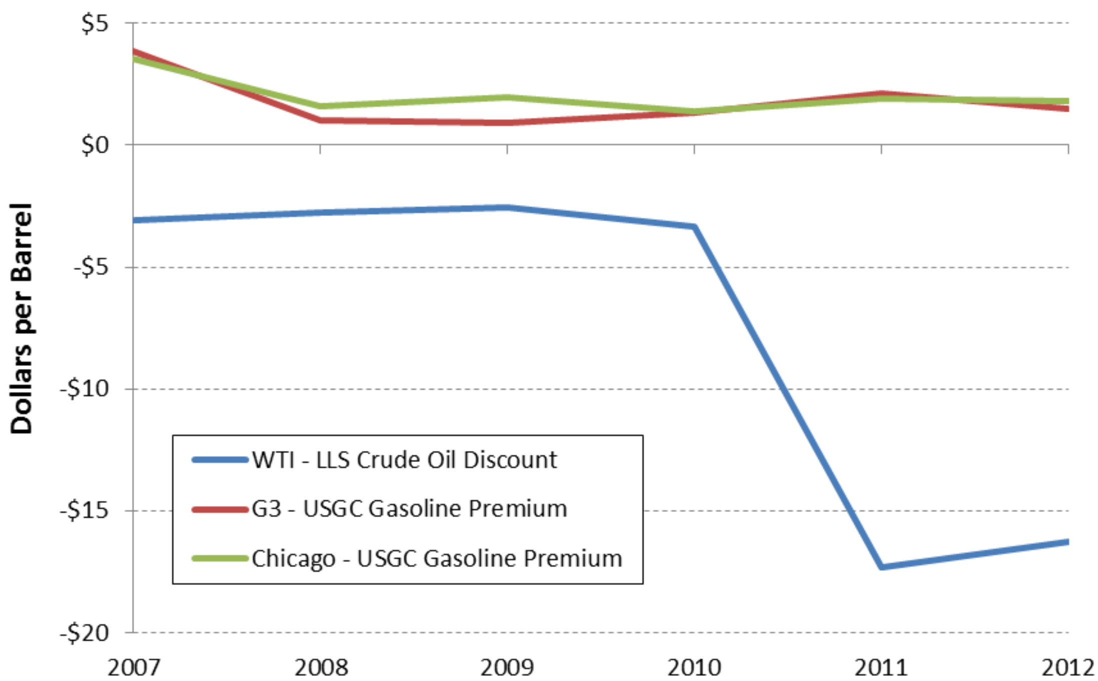
Also not examined above, are more speculative political impacts that might occur as a result of a decision on the permit application for the proposed Project. In 2012, the Canadian government enacted new laws changing the way some major infrastructure projects, such as pipelines, are reviewed. Among the changes made were limits on the amount of time for such reviews. A declared intent was to promote alternative routes for the export of WCSB crude oils, especially ones that would reduce reliance on the United States as, essentially, the sole market option.

1.4.8 Additional Market Issues From Scoping Comments—Crude Price Differences and Gasoline Prices

Comments were received during the scoping process for this Supplemental EIS and throughout the review process leading up to the Final EIS about whether the steep discounts in the Midcontinent and upper Midwest/Chicago crude prices were resulting in lower gasoline prices for Midwest consumers, and, conversely, whether approving a project that would relieve the crude bottleneck at Cushing would raise gasoline prices in the Midwest. As the Seaway pipeline(s) and the Gulf Coast Project will provide more pipeline transport capacity from Cushing, Oklahoma, to the Gulf Coast, this issue is not solely related to the proposed Project. Because of the significant public interest in the question, and because it provides additional helpful background on the North American crude oil market, this issue is discussed briefly below and further information and analysis of this issue is provided in Appendix C, Market Analysis Supplemental Information.

Since early 2011 there has been a glut of crude oil at the Cushing, Oklahoma, oil hub where WTI crude oil is priced. This glut has been caused by a variety of factors including growth in domestic light crude production, displacement of light crude by several refiners bringing on-line heavy crude upgrading projects in the Midwest to process heavy WCSB crude oils, and constraints in the transportation capacity out of Cushing because of the change in production areas and associated crude flows. With no viable options to move light crude to coastal refineries, notably on the Gulf Coast, the crude at Cushing and further north to the Bakken region became heavily discounted by producers relative to traditional markers such as Light Louisiana Sweet (LLS) or Brent. This led to the prevailing highly unusual market situation where a Gulf Coast 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). This situation gives refiners in the Midcontinent region that purchase crude oil based on the WTI price a significant crude oil cost advantage over Gulf Coast (or East or West Coast) refiners that rely on purchases of foreign crude oils since those are priced off Brent or other international markers.

The steep discounts in crude prices in the Midcontinent and upper Midwest/Chicago regions compared to Gulf Coast crude prices have not, however, resulted in lower wholesale gasoline prices in those regions compared to the Gulf Coast. According to market data, (Figure 1.4.8-1), despite the discounts in WTI and hence regional crude prices, wholesale product prices in the Chicago and Group 3 markets—for the most part—have not followed crude price discounts. Figure 1.4.8-1 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 1.4.8-1), the wholesale price of gasoline in the Midwest (Chicago and Group 3 region) has remained generally higher than that on the Gulf Coast (shown by the green and red lines in Figure 1.4.8-1). This is because there is an active flow of gasoline, and other clean products, from the Gulf Coast into the Midwest, mainly via the Explorer pipeline. As a consequence, Midwest product prices are derived from Gulf Coast prices, both of which are in turn driven by international (rather than U.S. inland) crude oil prices. Enabling (additional volumes of) WCSB crudes to flow to the Gulf Coast would not change this dynamic. What would change it is product demand or refinery processing changes that result in product flowing out from the Midwest to the Gulf Coast rather than the opposite.



Source: Bloomberg 2012.

Notes: 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).

Figure 1.4.8-1 Average Crude Oil and Gasoline Price Spreads, $/bbl

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