Appendix 3-6

IHS Report, Supply and Market Study for the Energy East Project – September 2015

IHS

Supply and Market Study for Energy East Project

September 2015
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Contents

Introduction

TransCanada is developing a project called Energy East – a 1.1 million barrels per day (MMb/d) pipeline that would deliver crude oil from Western Canada and the Williston Basin to refiners in Montreal, Quebec City, and Saint John, New Brunswick. In addition to the pipeline, the project will deliver to a marine terminal in Saint John, New Brunswick. When completed, the Energy East project will provide Western Canada and Williston Basin crude oil producers with efficient pipeline access to markets which they are currently unable to reach by pipeline, and so will increase the interconnection and breadth of the North American crude oil pipeline network. IHS has been engaged to provide an independent assessment of crude oil supply and markets which could be served by the Energy East Project.

In addition to this introduction, the report has four parts and various Appendices.

- Summary of Conclusions
- Part 1: Western Canadian and Williston Basin crude oil supply
- Part 2: Western Canadian and Williston Basin crude oil: Existing markets and export capacity
- Part 3: Possible markets served by Energy East (Eastern Canada, US East Coast, US Gulf Coast, and other Offshore)

The main text is followed by Appendices A through F which contain supporting information to the main report.

This report was completed in September 2015, and reflects the historical information available at that time, along with IHS' forecasts and others' expectations at that time. Forecasts are inherently uncertain and subject to revision as market circumstances change.

Throughout this report, we refer to various crude oil terms including oil sands products, bitumen blends and Synthetic Crude Oil (SCO), as well as crude qualities (light sweet, light sour, and heavy). For definitions, see Appendix A.

About IHS. IHS is a global information company that provides comprehensive content, insight and expertise to business and government clients around the world. Since 2005, IHS is a publicly traded company on the New York Stock Exchange. Headquartered in Englewood, Colorado, as of September 2013, the company employs over 8,000 people worldwide.

IHS Energy Insight Consulting offers industry and business advisory expertise across the energy value chain: upstream, midstream, downstream, and chemicals. In this report our information is sourced as either IHS or IHS Energy.

About William J. Sanderson. Mr. Sanderson is a Vice President of IHS Global Inc., in the Oil Markets and Downstream organization. Prior to joining IHS, Mr. Sanderson was President and CEO of Purvin & Gertz Inc. (“Purvin & Gertz” or “PGI”). IHS acquired PGI in November 2011. Mr. Sanderson’s business address is 600 Travis Street, Suite 2150, Houston, Texas, 77079, USA. A complete resume is provided in Appendix F.

Summary of Conclusions

North America has experienced rapid growth in crude oil production, and continued growth is expected in spite of the decline in global crude oil prices that occurred in late 2014. Western Canada's oil sands are a major driver of growth, with new infrastructure needed to provide efficient access to markets for Western Canadian producers. Pipeline projects are proposed to expand capacity to move Western Canadian production to the West, to the South, and to the East. The Energy East Project has been designed to provide capacity to move up to 1,100,000 b/d of Western Canadian production to Eastern Canadian refiners as well as to an export facility for onward delivery to the US East Coast, the US Gulf Coast, Europe, India, and other destinations. The pipeline will have the capability to receive up to 280,000 b/d of Williston Basin crude production to move to the same markets. The Energy East project would benefit both producers and refiners:

- **Benefits to Producers** include enhanced access to existing markets, access to new markets, and improved netbacks due to the greater efficiency of pipeline transportation.
- **Benefits to Refiners** include lower cost transportation for Western Canadian crude deliveries to refiners on the east coasts of Canada and the US, enhanced access to Western Canadian crude oil at competitive transportation costs for US Gulf Coast and European refiners, and increased supply diversity for refiners in India.

The value of enhanced market access has been clearly evident in recent years. Oil sands and other Western Canadian crudes have experienced deep discounts relative to competitive crudes due to the high cost of rail transport versus pipeline transport. Price discounts would be expected to persist as long as pipeline capacity remains inadequate. Energy East would play a vital role in providing sufficient pipeline capacity to reduce or eliminate these price discounts. A number of projects are currently proposed and are in various stages of the approval process. Energy East would have the largest Western Canadian takeaway capacity of the currently proposed projects, and provide efficient access to a number of diverse markets, to the benefit of both crude oil producers and crude oil consumers. Its capability to deliver to Eastern Canadian refineries would provide lower cost transportation for Canadian crudes, increased supply diversity, improved supply security, and the capability to reduce offshore imports. For Western Canadian producers, Energy East would increase market access, enhance market diversity, enable market expansion, and contribute to higher netback prices for producers due to the elimination of extraordinary price discounts.

Expected netback prices under pipeline construction scenarios which provide adequate pipeline capacity are approximately US$20[1] per barrel higher than netbacks under the scenario in which none

[1] In this report, crude oil pricing and related quantities are expressed in US dollars. The benefits accruing to the Canadian producing sector are expressed in both US dollars and Canadian dollars.

of the proposed projects move forward, and approximately US$9 per barrel higher than those scenarios which require rail capacity to transport the expected level of production.

The benefits of higher netback prices created by pipeline capacity additions would flow directly to crude oil producers, and indirectly to the overall Canadian economy. If all of the currently proposed pipeline capacity addition projects proceed, for the period 2021-2040 (20 years of Energy East operation), the gross netback improvement that is expected to accrue to the producing sector is estimated at C$663 billion (US$590 billion) (in constant 2014 dollar terms). The portion attributable to the Energy East Project is estimated at C$161 billion to C$217 billion (US$142 billion to US$193 billion). If only Energy East is constructed, its full C$204 billion (US$183 billion) netback benefit would be attributable to Energy East. The lost revenue from Western Canadian crude price discounts not only impacts producers, but also impacts governments. If Western Canadian crudes were not subject to price discounts, royalties and taxes would be higher.

Given the uncertainties surrounding the completion schedules for major pipeline projects, IHS concludes that Energy East is a very important element in the transportation industry’s efforts to provide secure and diverse market access and efficient delivery for producers and consumers of Western Canadian crude oil.

Summary of Revisions Contained in this Report

While this report should be considered a complete and independent document, it should also be considered to be an update of the IHS report originally completed in September 2014 covering the same subjects. The structure, information coverage, analytical approaches, and conclusions of this report are very similar to those contained in the prior report. A brief summary of the key changes follows:

- **Changes to Energy East Project**
  - Since September 2014, TransCanada has changed the configuration of the Energy East project somewhat. Most importantly, the proposed marine terminal at Cacouna, Quebec is removed from the scope of this application. That change has been reflected in the description of the project contained in this report as needed. However, the review of delivery logistics in this report remains focused on loadings from the proposed Saint John terminal, as it was in the prior report, and so the change has no impact on the analysis and conclusions in the report.
- **Changes to Market Environment**
  - Since the prior report was issued, the price of crude oil in the North American and global markets has declined significantly. At the time of this writing, crude oil prices have fallen by 50% or more from the high points experienced in 2014. IHS now expects crude oil prices to remain at these lower levels for the next two years, but to return to higher levels by 2020 as production growth slows and demand accelerates. Over the 2020 to 2040 period, the projected crude prices used in this report are approximately 10% below the forecasts contained in the prior report.
  - The sharp reduction in crude oil prices has resulted in a significant drop in the near-term outlook for crude oil production growth in both the US and Canada. However, the lower prices are also resulting in reduced exploration and development costs, somewhat offsetting the impact on production economics. As a result, IHS now expects production growth to recover in 2017 and beyond. IHS' projections for Canadian crude oil production during 2020-2030 average roughly 500,000 b/d lower than those contained in the prior report. The revised CAPP outlook referenced in this report has been reduced by an average of 900,000 b/d during 2020-2030 versus the prior CAPP outlook. The updated production outlooks were used in this report.
  - The relationship of the Canadian dollar to the US dollar has also changed significantly since the prior report was completed. From a relationship near parity, the Canadian dollar has fallen to less than 80% of the value of the US dollar at this time. Rather than an exchange rate at parity, IHS now expects the long-term value of the Canadian dollar to average roughly 90% of the US dollar. IHS' projections are used in this report.

  - While none of the major pipeline expansion projects considered in the prior report have been cancelled, the expected in-service dates have been delayed, and other system changes have been implemented. In this report, IHS has reevaluated the existing and proposed pipeline capacity available to transport Western Canadian crude oil to market, and used the revised expectations to analyze the expected balance between capacity and production.
- **Updates to Methodologies and Included Information**
  - Market information has been updated throughout this report, including tabular data, graphics, and information contained in the text. For example; refinery capacities are presented for 2015 rather than 2014, and crude oil supply estimates are provided for 2014 rather than earlier years.
  - The calculation of the revenue benefits to the producing sector has been updated to incorporate the updated production outlook, the updated price outlook, the updated pipeline capacity outlook, and the updated schedule for Energy East completion. The revenue benefits are now provided in both Canadian and US dollars, based on the IHS outlook for exchange rates. Regardless, the estimates of the aggregate benefits as well as the benefits attributable to Energy East are similar in magnitude to the estimates contained in the prior report.
- **Changes to Conclusions**
  - In spite of the many numerical changes to the analysis contained in this report, the basic conclusion remains the same – that Energy East is a very important element in the transportation industry's efforts to provide secure and diverse market access and efficient delivery for producers and consumers of Western Canadian crude oil.

Part 1) Western Canadian and Williston Basin crude oil supply

North America is experiencing a significant revival of oil production driven by light sweet tight oil and heavy oil sands developments. Since 2010, the two sources combined grew 4.3 MMb/d (2010 to 2014).[2] The pace of growth has been slowed by the recent decline in global crude oil prices, as companies have reduced capital spending and development activity. However, activity is expected to increase as the industry adjusts to the lower price levels. From now to the end of this decade (2020), tight oil and oil sands product output are expected to grow by another 3.7 MMb/d.[3] The Energy East project capitalizes on both of these trends, transporting oil sands products (along with other Western Canadian oil supply) and tight oil from the Williston Basin to new destinations in North America and overseas. The starting point for the Energy East project will be in Western Canada, specifically at the terminal in Hardisty, Alberta. Crude oil will also enter the pipeline at a terminal in Saskatchewan.

This section of the report describes the outlook for Western Canadian and Williston Basin crude oil supply.

Western Canada Oil Supply Outlook

To help quantify the supply growth from Western Canada over the next 20 years, we have presented two supply outlooks: IHS and Canadian Association of Petroleum Producers (CAPP) (See Figure 1).[4]

IHS Supply Outlook (Q2 2015). We expect Western Canadian supply to grow from 3.7 MMb/d in 2014 to 5.9 MMb/d in 2030. Future supply growth is primarily from oil sands, with most growth provided by heavy crude oils called bitumen blends. Due to weak upgrading economics, we expect little or no supply growth from Synthetic Crude Oil (SCO) (see Appendix B for more information). When tight oil growth is considered along with expected declines in conventional production, overall light crude supply is expected to remain roughly flat between 2014 and 2030. Tight oil is expected to grow, albeit not as much as in the United States. However, tight oil development in Canada is still in its early stages, and it is possible that production from tight oil could surpass our outlook.

CAPP Production Outlook (2015). CAPP's 2015 supply outlook, released in June 2015, expects Western Canadian supply to reach 6.1 MMb/d by 2030 (roughly 0.2 MMb/d higher than IHS). Similar to IHS, CAPP's outlook is dominated by bitumen blends and SCO shows little growth. Total conventional

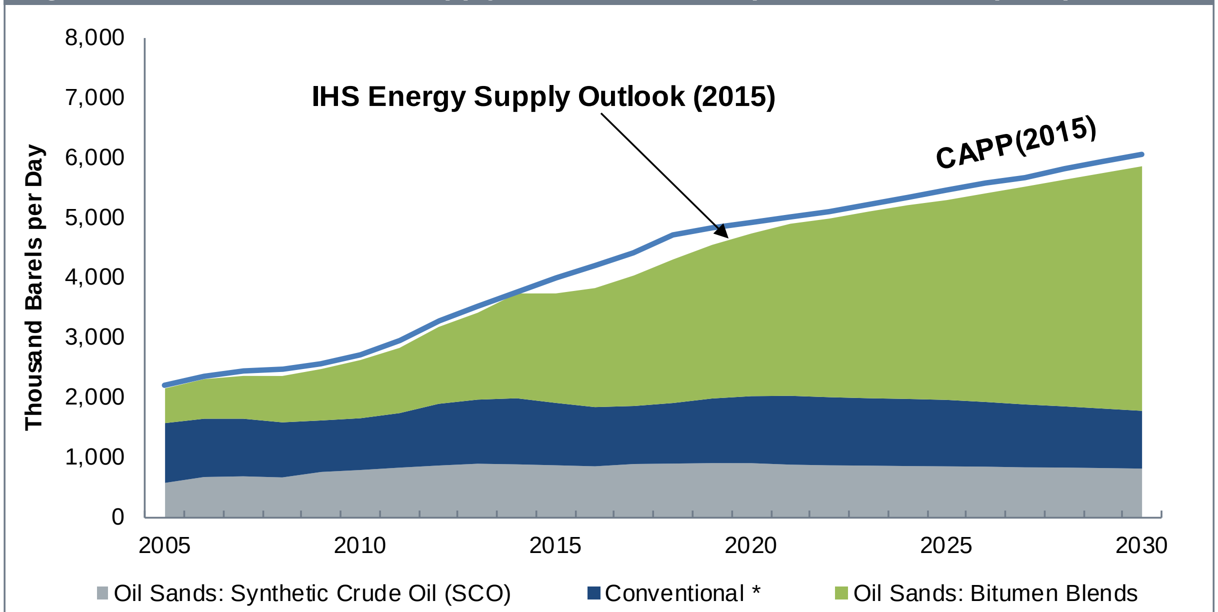
[2] North American tight oil growth was 3.4 MMb/d (2010-2014); oil sands SCO and diluted bitumen was 872,000 b/d (2010-2014).

[3] IHS' outlook for oil sands SCO and diluted bitumen production is to grow from 2.6 MMb/d (2014) to 3.5 MMb/d (2020). Tight oil is expected to grow another 2.7 MMb/d (2014 to 2020).

[4] All values in this section are "as-marketed" supply. For oil sands bitumen and other heavy conventional crudes, this means the diluents required to ship the crudes are included in the reported values. For more information on bitumen blends, please see Appendix A.

light crude supply (including light, medium and tight oil crudes) is expected to decline by 0.1 MMb/d between 2014 and 2030. The most significant difference between the two production outlooks occurs in the 2015 to 2020 time period. The IHS outlook expects weaker prices to result in little production growth in 2015-2016, with growth recovering from 2017 to 2020. The CAPP outlook anticipates production growth to continue unabated in the near term before the rate of growth slows from 2019 onward.

Figure 1: Western Canadian Supply Outlook: IHS compared with CAPP (2015)



Source: IHS Energy (2015) CAPP (2015) *Conventional production includes tight oil © 2015 IHS

Williston Basin Oil Supply Outlook

The Williston Basin is an oil producing region that covers parts of Saskatchewan, Manitoba, Montana, North Dakota and South Dakota. Supply growth in the Williston Basin is dominated by tight oil. Tight oil is produced from a variety of formations with low permeability and porosity—including shales, tight sands, and tight carbonates. Tight oil reservoirs were once deemed too expensive to produce economically, but are now being produced through the use of horizontal drilling and advanced completion techniques. Between 2010 and 2014, production from North American tight oil grew 3.2 MMb/d, with production from the Williston Basin accounting for about a quarter of this growth.

From 2014 to the end of this decade (2020), we expect total North American tight oil will grow by another 2.7 MMb/d. For the Williston Basin region specifically, IHS expects crude oil supply will ultimately peak at over 2.2 MMb/d around 2030.

Part 2) Western Canadian and Williston Basin crude oil: Existing markets and export capacity

This part of the report covers the existing markets for both Western Canada and the Williston Basin crude oils. The drivers for new markets are explained, as well as the export capacity (both current and future) from each region.

Throughout Part 2 and Part 3 of this report, we refer to the markets for Western Canadian and Williston Basin crude oils. The geographic border for each region is described below (also see Figure 2 for a map that includes the regional boundaries):

- **Western Canada** – British Columbia, Alberta, Saskatchewan and Manitoba.
- **Ontario**
- **Eastern Canada** –Quebec and all Canadian Atlantic provinces (New Brunswick, Nova Scotia, Prince Edward Island, and Newfoundland and Labrador).
- **US East Coast** – US states along the entire Eastern seaboard—from Maine to Florida (PADD I)
- **US Gulf Coast** – New Mexico, Texas, Louisiana, Mississippi, Alabama, and Arkansas (PADD III)
- **US West Coast** – US states on the entire west coast as well as Arizona and Nevada (PADD V)
- **US Rockies** – Five US states around the Rocky Mountain range—Montana, Idaho, Wyoming, Utah and Colorado (PADD IV)
- **US Midwest** – Covers a large area of the inland region of the US. The northern limit of the region spans from North Dakota across all states that border the Great Lakes. The region's southern border includes Oklahoma, Missouri, and Tennessee. (PADD II)

Western Canada: Existing Markets and Export Capacity

Some New Demand in Local Market

Western Canadian refineries rely almost exclusively on crudes produced within the region. There are eight refineries in Western Canada with a total crude distillation capacity of 679,000 b/d. In 2014, total crude runs in Western Canada averaged 556,000 b/d, which included a small volume of light crude imported from the US. About one-third of the demand was heavy crudes (conventional and oil sands) with the remainder light crudes (see Appendix C for more details). The North West Redwater Partnership is building a new refinery in Sturgeon County, Alberta. The facility intends to produce diesel along with diluents for blending with oil sands bitumen. The start-up of Phase 1 is anticipated in September 2017. On commissioning, it would increase Western Canada bitumen consumption by 50,000 b/d.

Existing Crude Oil Outlets: Nearing Saturation

Western Canada currently has limited outlets for outward deliveries of crude oil. Today, other than satisfying demand in Western Canada (including British Columbia), the region's crude oil is mostly consumed in the markets that are connected by pipeline—Ontario, US Midwest, US Rockies, and US

Pacific Northwest. Due to limited infrastructure for transporting crude oils elsewhere, relatively small volumes of Western Canadian crude oil have historically been consumed in other regions such as the US Gulf Coast, US East Coast, and offshore. The portion of crude consumed in each region is as follows (also see Table 1):

- **Canada (25%).** In 2014, IHS estimates that 57% of the 945,000 b/d of Western Canadian crude that was consumed in Canada stayed in Western Canada. Most of the rest was consumed in Ontario, with only small volumes reaching Eastern Canada due to infrastructure limitations.
- **United States (73%).** In 2014, an estimated 79% of the crude sent to the US from Western Canada was consumed in the US Midwest and Rockies regions. The Gulf Coast, East Coast, and West Coast consumed smaller amounts due to limited infrastructure.
- **Offshore (2%).** In 2014, only about 2% of Western Canadian crude was estimated to have been exported to non-US locations due to limited infrastructure.

Table 1: Disposition of Western Canadian Crude Supply by Market (2014)

	Crude Consumption (Thousand B/D)	Percent
Western Canada (including British Columbia)	543	15%
Ontario and Eastern Canada	402	11%
Offshore	80	2%
US Midwest	1,878	50%
US Rockies	253	7%
US Gulf Coast	255	7%
US West Coast	211	6%
US East Coast	107	3%
Total Western Canadian Supply	3,730	100%

Source: IHS estimates using NEB, EIA, and Statistics Canada data

Pipelines under Development in Three Directions

In a response to the need for more pipeline capacity and market diversity, over 3 MMb/d of new pipeline capacity is under development. If all the projects described below are constructed, new pipelines could move growing oil supply from Western Canada in three directions (See Figure 2 for pipeline routes and market definitions):

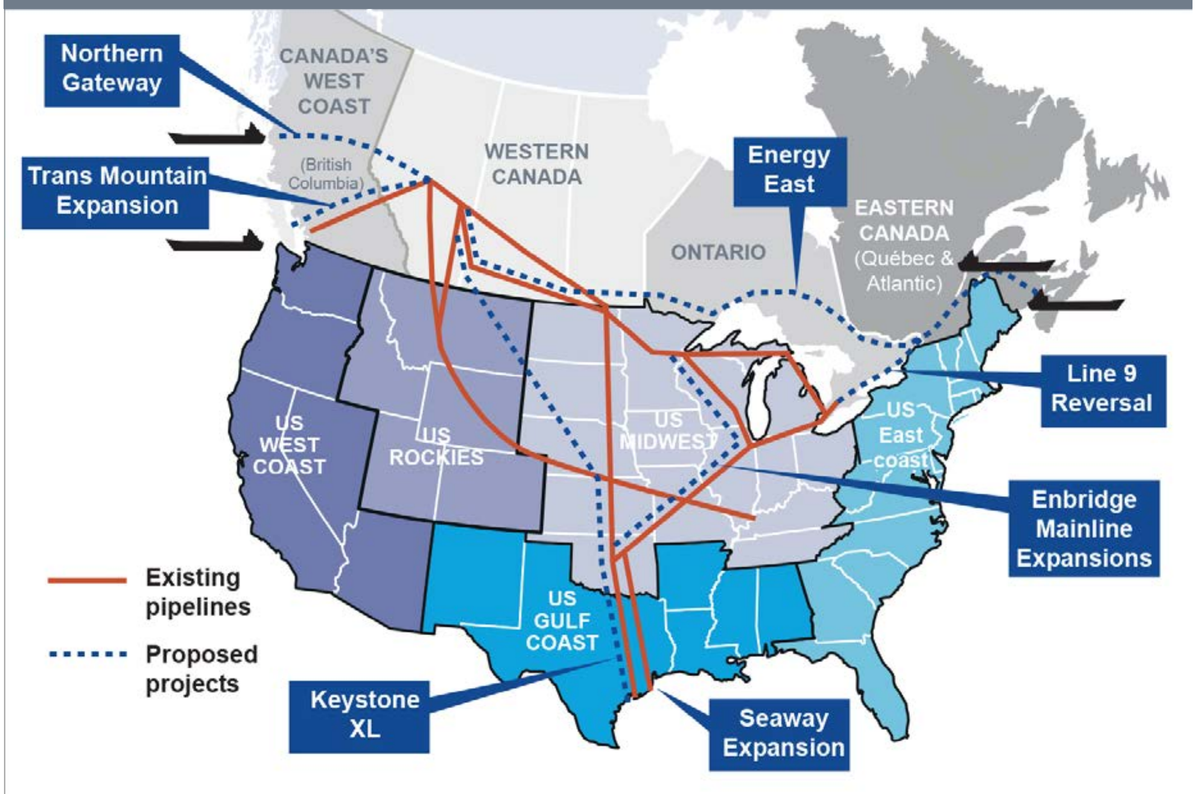
- **West (Northern Gateway and Trans Mountain Expansion).** Both projects plan to move crude oil from Alberta to Canada's west coast by pipeline. At the Canadian West Coast, crude oil will have access to the US West Coast and Asian refining markets.
- **East (Energy East and Line 9 Reversal).** Both projects plan to deliver crude from Western Canada and the Williston Basin to Eastern Canada. In itself, the Line 9 reversal does not add new export capacity from Western Canada, but it extends the reach by enabling up to 300,000 b/d of crude from the Enbridge Mainline to flow to Ontario and Montreal. Compared to the Line 9 reversal, the capacity of Energy East is almost four times larger. Energy East could deliver crude

oil to Montreal, Quebec City, and Saint John. At Saint John, the crude oil can also be loaded into tankers that could deliver crude oil to the US East Coast, US Gulf Coast, and overseas markets.

- **South (Enbridge Mainline/Seaway expansions and Keystone XL).** Both projects plan to deliver crude from Western Canada and the Williston Basin to the US Gulf Coast. Through the expanded Enbridge system, crude would be delivered to Cushing, Oklahoma before moving on the Seaway pipeline to the US Gulf Coast. Keystone XL plans to deliver the crude directly to the US Gulf Coast.

The construction of new pipeline capacity not only provides increased access to customers that can currently process oil sands products and Williston Basin crude oil, but also may provide supply for future refinery expansion projects. For example, by the end of the next decade, IHS expects the collective refining capacity of China and India to grow by more than 50%. The projected growth in these countries could be satisfied, in part, with Western Canadian production. The potential diversity of supply routes that the multiple projects offer also serves to enhance the security of future supply for refiners evaluating investments.

Figure 2: Western Canada: Proposed export pipelines and markets



Source: IHS Energy

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Supply from Western Canada is projected to increase by almost 60% by the end of the next decade, creating the need for market expansion. In addition, the recent rapid growth of US tight oil production has accelerated the urgency for Western Canadian crude oils to create pipeline connections to new markets — for both heavy and light crude oils:

- **Heavy Crudes**: Western Canadian bitumen blend supply is expected to grow by roughly 150,000 b/d each year, on average, through 2030. Sophisticated refineries with coking units are required to process growing volumes of bitumen blends, as coking units allow refineries to convert the heaviest part of the crude to transportation fuels. With coking refineries in the traditional markets approaching their limits for processing Canadian heavy crudes, two methods are left for growing demand:
    - **Adding coking capacity to refineries in the traditional markets.** Over the past few years, three Midwest refiners – WRB Refining Wood River, Marathon Detroit, and BP Whiting – built coking units to increase their capacity to process Canadian heavy crude. However, these investment decisions were made before the potential scale of tight oil production was well understood. Now, growing production from tight oil is reducing the incentive for further investment in heavy oil conversion projects in the Midwest. Moreover, even if some coking capacity were added in the existing markets, those markets could not keep pace with the rapid rate of bitumen blend supply growth. For example, in the US Midwest today, only about 1 MMb/d of refining capacity currently lacks coking capacity.[5] Even if cokers were added to all of this Midwest refining capacity, and the capacity of existing cokers were expanded by 25%, this would only accommodate projected oil sands production growth through 2020.
    - **Building infrastructure to access new heavy crude markets**. With limited options for adding coking capacity to refineries in the traditional markets, connections between Western Canada and new refining markets are needed.
- **Light Sweet Crudes**: Due to growing US domestic tight oil production, the market for Western Canadian light sweet crude in the United States is shrinking. In fact, we expect that growth in US tight oil will eventually be large enough to replace most of the Canadian light sweet crude oil imports to the US Rockies and US Midwest. This, combined with the recent conversions of light sweet crude refineries in the Midwest to take heavy crude (mentioned above), is further decreasing demand.

Since the existing outlets for Western Canadian crude oil—Ontario, US Midwest, and US Rockies—are not served by the Energy East project and have limited prospects for further increasing their demand, they are not discussed further in this report.

Western Canada Pricing Issues

Due to limited transportation infrastructure and long distances to market, Western Canadian crudes have frequently traded at price discounts compared to crude oils in other regions. Discounts occur when supply exceeds refining demand, causing surplus supply to travel longer distances and use

[5] Using IHS estimates combined with Oil & Gas Journal data (2015), the Midwest has only 1 MMb/d of refining capacity that does not already incorporate coking capacity.

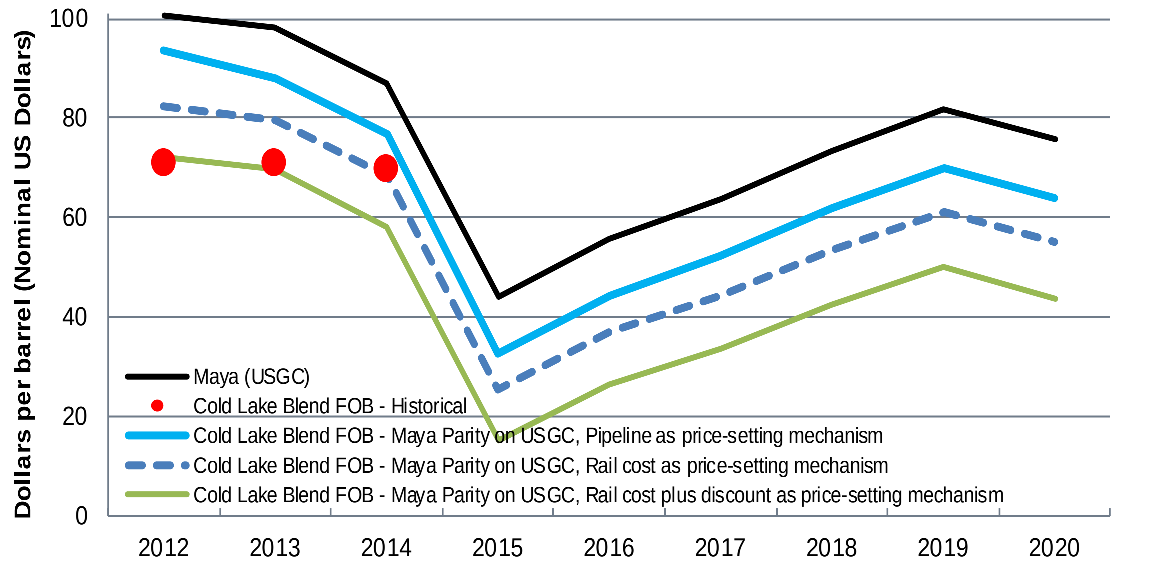
higher-cost modes of transportation (such as rail) to find markets; resulting in price discounts for all production.

Until this year, growth from oil sands and tight oil had surpassed demand in the traditional markets creating an oversupply and ensuing price discounts (see Figure 3). For example, in 2013, when prices are adjusted for transportation costs between Western Canada and the US Gulf Coast and quality differences are accounted for, Mexican Maya on the US Gulf Coast sold for approximately US$17.50 per barrel more than similar crudes in Western Canada. Price discounts were not limited to heavy crudes: all Western Canadian crude oils were discounted. In 2013, if Western Canadian supply had market access through more efficient transportation methods, we estimate that crude oil revenues would have been between US$14 and US$19 billion more (see Appendix C). For 2014, the total impact is estimated at US$3 to US$9 billion (see Appendix C).

The sharp reduction in global crude oil prices in late 2014 compressed crude oil location, quality, and market differentials. The price decline also reduced the pace of production growth and eased the surplus of crude production relative to pipeline capacity, aided by recent pipeline capacity expansions. As a result, Western Canadian crude prices are expected to demonstrate minimal discounting in 2015 after accounting for quality and location differences. However, as Western Canadian production grows, as expected in the IHS and CAPP production outlooks, the volume of new supplies would result in a return to price discounting unless pipeline capacity expands in parallel. If the currently expected pipeline projects are completed on their currently-anticipated schedules, then the extraordinary price discounts would be resolved. Otherwise, if insufficient pipeline capacity is built and the capacity to move Western Canadian crude to market remains inadequate, then the extraordinary discounts would remain in place. Rail take away capacity appears to be sufficient in 2015 and may remain so, even if insufficient pipeline capacity is built. However, this condition would still result in Western Canadian crude being significantly discounted due to the higher costs of rail transportation versus pipeline transportation.

Western Canadian production is expected to increase steadily, and pipeline capacity requirements will increase in parallel. To maintain adequate capacity and prevent the extraordinary discounts from returning, future pipeline capacity expansion projects – such as the Energy East project – will have to continue to be placed into service over the coming years. Figure 3 shows the price forecast under the three scenarios – adequate pipeline capacity, inadequate pipeline capacity with sufficient rail capacity, and inadequate pipeline capacity with insufficient rail capacity, in which extraordinary discounts at the levels experienced in recent years are maintained.

Figure 3: Price Discounts for Western Canadian Heavy Crude: Minimized if pipeline capacity remains adequate



Source: IHS (outlook); Platts, ©2014 by The McGraw-Hill Companies, Inc. (historical).
Disclaimer: Historical oil price data are extracted or derived by IHS CERA from Platts. All rights reserved. All liability for errors and omissions is hereby excluded by Platts and its sources. No representations or warranties are made by Platts or its sources concerning the data or any conclusions to be drawn from it.
Note: Cold Lake Blend prices adjusted for quality differentials relative to Maya

The lost revenue from Western Canadian crude price discounts not only impacts producers, but it also impacts governments. If Western Canadian crudes were not subject to price discounts, royalties and taxes would be greater.

The pricing issues have provided a financial incentive for Western Canadian crude oils to reach new markets – particularly markets that reflect global crude prices instead of discounted prices. They also highlight the risks that stem from a lack of market diversity and the need for optionality.

The Growth of Rail

The inadequacy of export pipeline capacity has forced Western Canadian producers to use rail to transport their production to market. We estimate that Western Canadian rail volumes have increased from near zero at the start of 2012 to an average of 180,000b/d in 2014, with some months exceeding 200,000 b/d[6]. We expect that rail volumes will continue unless enough new pipeline capacity is built so that capacity exceeds supply. At that point, the majority of rail shipments would no longer be necessary. However, we expect that some rail movements would continue, since rail can ship crude oil to refiners that cannot access some crude oil supplies by pipeline. The rail infrastructure in place at that time is expected to be under-utilized going forward, but that does not necessarily imply that the parties that invested in rail have failed to achieve their targeted return on investment, since rail projects typically have shorter investment horizons than pipeline projects.

The emergence of rail transportation in Western Canada has served an important supply function. Without it, we expect that production growth could eventually become constrained. However, the use of rail results in an economic penalty for producers. The cost to transport crude oil is significantly higher by rail than if pipelines were used. Because of these higher transportation costs, when Western Canadian producers require rail transportation, the region's crude oil netback prices are lower than would be the case if sufficient pipeline capacity existed.

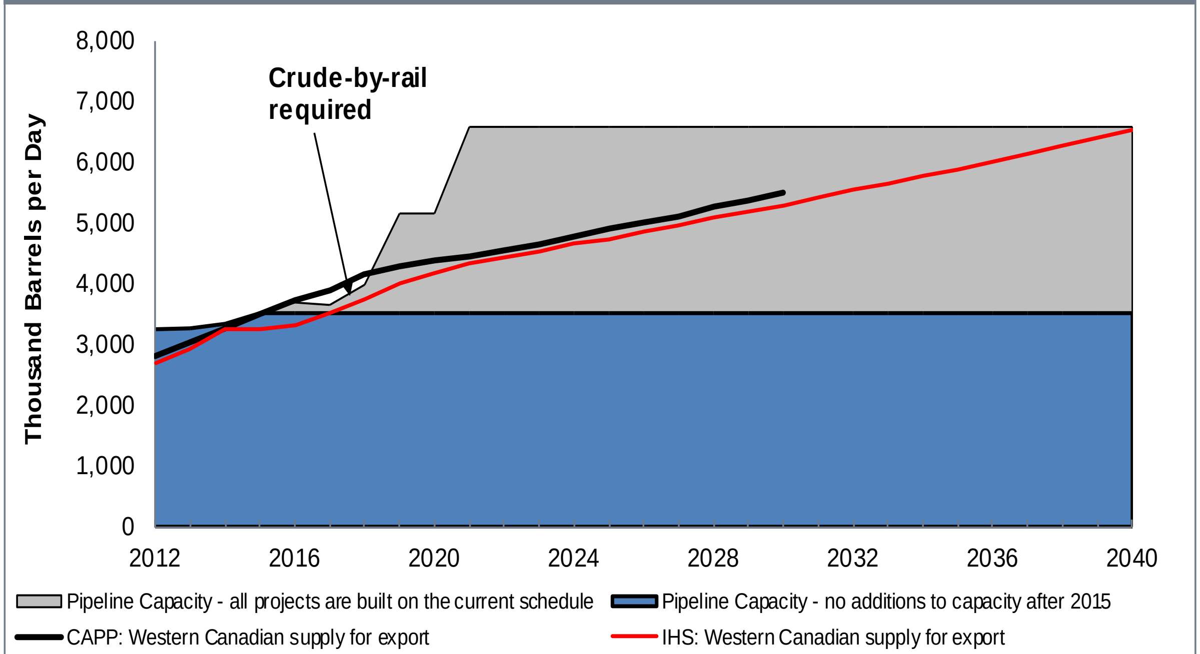
Future Pipeline Scenarios

In a scenario in which all pipeline projects are built according to their current schedules, the proposed pipeline projects would provide enough capacity to keep pace with supply until after 2030 under the both the IHS and the higher CAPP supply outlooks. In contrast, in a scenario in which no new pipelines are constructed from Western Canada, the gap between pipeline capacity and supply would grow steadily (see Figure 4 and Appendix C for more details).

The need for new pipeline capacity is very sensitive to the supply and pipeline availability assumptions. Due to the uncertainty in forecasting supply growth and pipeline project schedules, it is inherently difficult to perfectly time pipeline construction with supply growth. In addition, since pipeline capacity tends to be constructed in large increments while crude production grows at steadier rates, periods of apparent excess capacity are almost certain to occur if periods of insufficient capacity are to be avoided.

[6] Source: Crude Oil Logistics Committee

Figure 4: Western Canadian Supply for Export vs. Pipeline Capacity



Source: IHS Notes: Western Canadian total supply is reduced by the refining demand in Western Canada. Keystone XL, Enbridge mainline and Energy East total capacity have been adjusted to account for Williston basin crude receipts. See Appendix C, Table 5 for assumptions.

The difficulties inherent in accurately projecting pipeline capacity growth are exemplified by the Keystone XL project, which was originally scheduled for completion in 2012. In the analysis presented in this report, the Keystone XL project is projected to enter service in 2019, but final regulatory approvals for the US section were still outstanding at the time of this writing.

To illustrate the vulnerability of the Western Canadian capacity balance to the successful completion of the various projects currently proposed, two additional scenarios have been developed, as presented in Figure 5 and Figure 6. In this analysis, the currently planned capacity increases for the Enbridge (ENB) system are assumed to move forward, as they are relatively well advanced and are considered to be of higher probability. In addition to that capacity, the following combinations of projects are assumed to take place:

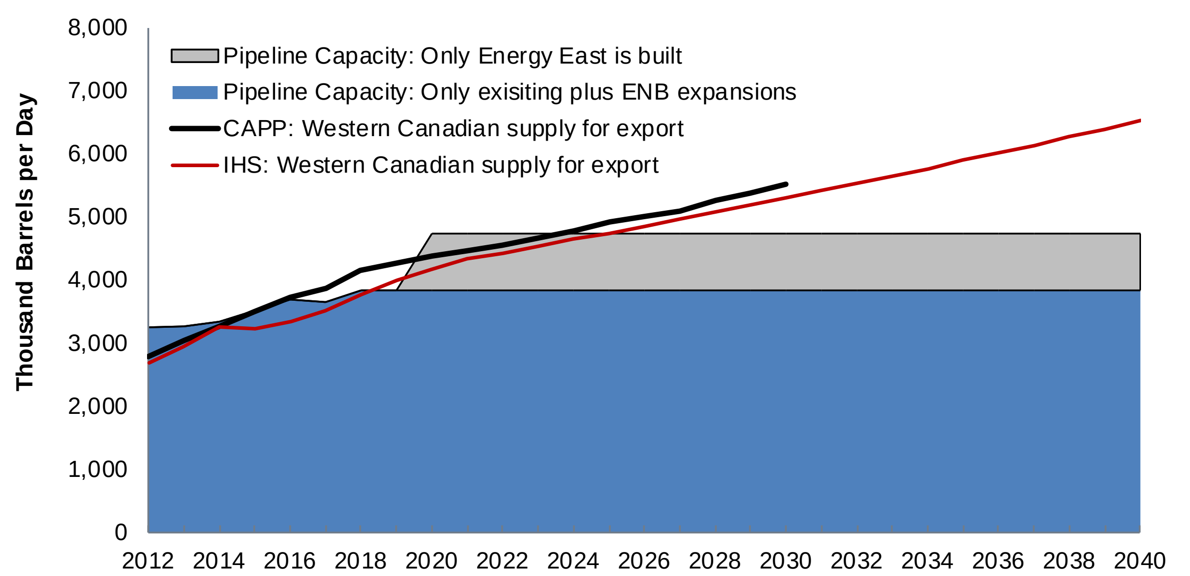
1. Only Energy East moves forward
2. Keystone XL (KXL), the Trans Mountain Expansion (TMX), and Northern Gateway (NGW) move forward

The balance between projected production and pipeline takeaway capacity is presented for each of these scenarios.

Pipeline Scenario 1: Only Energy East

In this scenario, pipeline takeaway capacity is inadequate after 2025 under the IHS outlook. Under the CAPP outlook, pipeline capacity would be inadequate after 2023.

Figure 5: Only Energy East

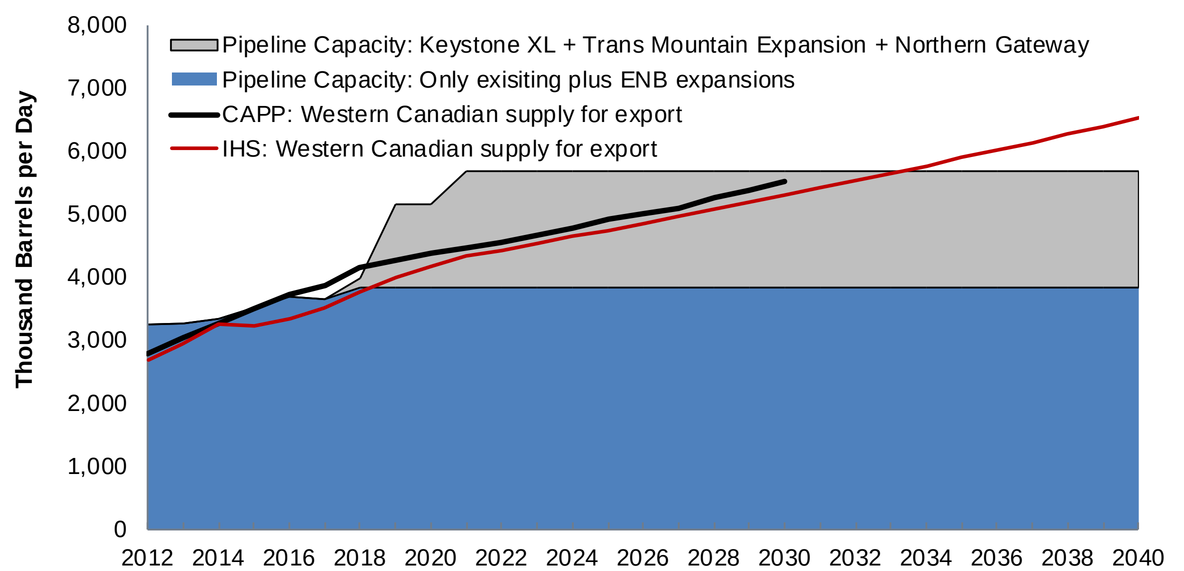


Source:IHS Notes: Western Canadian total supply is reduced by the refining demand in Western Canada. Keystone XL, Enbridge mainline and Energy East total capacity have been adjusted to account for Williston basin crude receipts. See Appendix C, Table 5 for assumptions.

Pipeline Scenario 2: Keystone XL, Trans Mountain Expansion, and Northern Gateway

In this scenario, pipeline takeaway capacity is adequate through 2030 under both the IHS and CAPP outlooks, but is inadequate after 2033 under the IHS outlook.

Figure 6: Keystone XL, TransMountain Expansion, and Northern Gateway

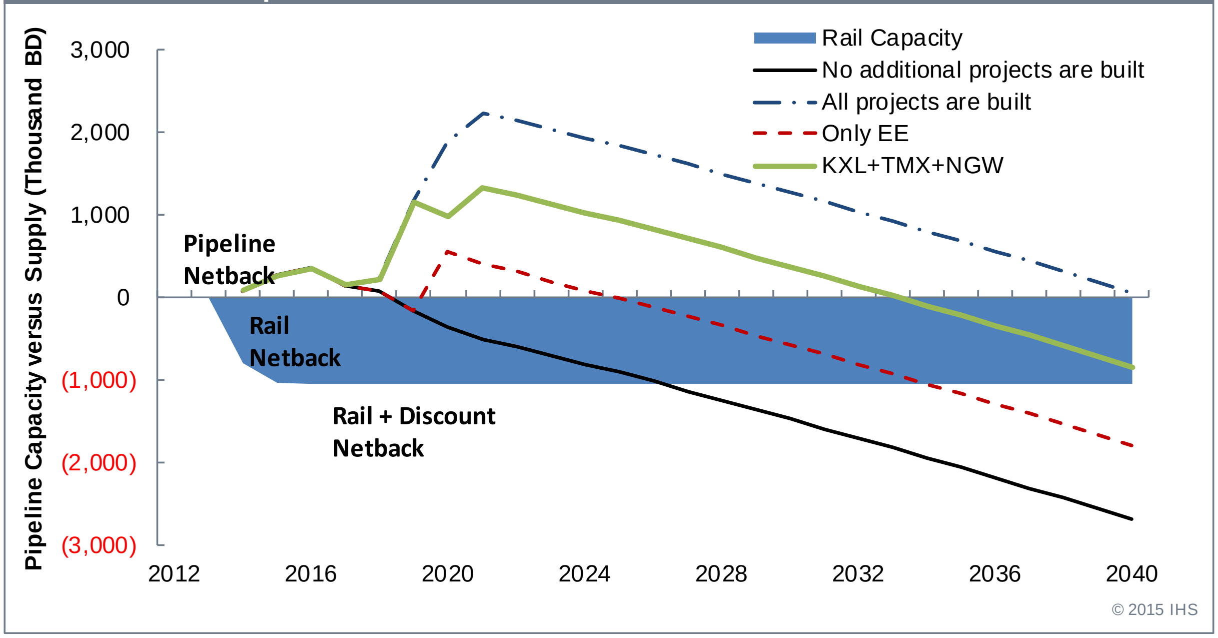


Source:IHS Notes: Western Canadian total supply is reduced by the refining demand in Western Canada. Keystone XL, Enbridge mainline and Energy East total capacity have been adjusted to account for Williston basin crude receipts. See Appendix C, Table 5 for assumptions.

Netback Pricing Implications

Netback prices for Cold Lake Blend have been analyzed for the two pipeline construction scenarios along with the scenario in which all projects move forward, as well as the scenario in which no projects move forward (other than the Enbridge expansions). Based on the IHS production outlook, the surplus/deficit of pipeline capacity relative to Western Canadian crude oil supply has been computed, and compared with Western Canadian rail loading capacity for heavy crude oil. As with pipeline capacity, rail loading capacity has been projected based on currently announced projects. Figure 7 summarizes the result of this analysis. For each scenario, the position of the surplus/deficit relative to rail capacity indicates the expected price-setting mechanism. If the deficit exceeds rail capacity, then extraordinary discounts would be anticipated, in addition to rail transport serving as the price-setting mechanism. If a pipeline capacity deficit exists, but the deficit is less than the available rail capacity, then rail costs would be expected to act as the price-setting mechanism. If pipeline capacity is adequate to transport all supply, then pipeline costs would be expected to act as the price-setting mechanism.

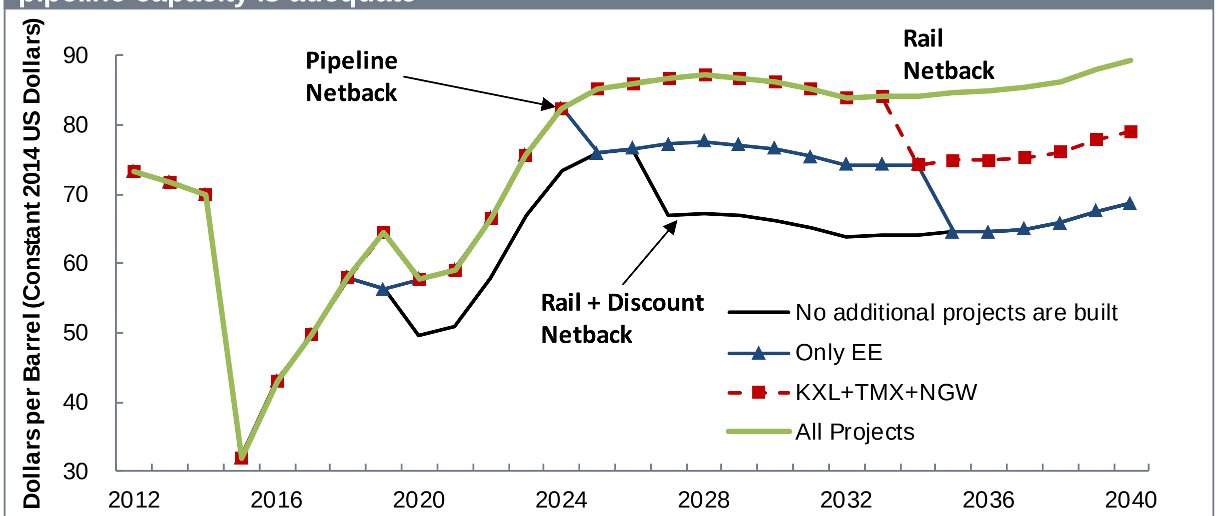
Figure 7: Pipeline capacity balances are expected to determine the mechanism setting crude oil netback prices



As Figure 7 illustrates, pipeline capacity is expected to be adequate until 2033 in Scenario 2, and through 2040 if all four proposed projects are completed as assumed. If only Energy East is built, then pipeline capacity would be adequate from 2020 through 2025. Rail transport would be required after 2025. If no projects are completed other than the Enbridge capacity increases, then both pipeline and rail capacity would be insufficient from 2027 onward.

Based on this analysis, Western Canadian netback prices for Cold Lake Blend are presented in Figure 8. Expected netback prices under the scenarios which provide adequate pipeline capacity are approximately US$20 per barrel higher than netbacks under the scenario in which none of the projects move forward, and approximately US$9 per barrel higher than those scenarios which require rail capacity to transport the expected level of production.

Figure 8: Netback Prices for Western Canadian Heavy Crude: Prices are highest if pipeline capacity is adequate



Source: IHS (outlook); Platts, ©2014 by The McGraw-Hill Companies, Inc. (historical).
Disclaimer: Historical oil price data are extracted or derived by IHS CERA from Platts. All rights reserved. All liability for errors and omissions is hereby excluded by Platts and its sources. No representations or warranties are made by Platts or its sources concerning the data or any conclusions to be drawn from it.

Gross Benefits to the Producing Sector

The benefits of higher netback prices created by pipeline capacity additions would flow directly to crude oil producers, and indirectly to the overall Canadian economy. The aggregate gross benefits to the producing sector have been estimated by assuming that the netback price increases computed for Cold Lake Blend would be applicable to all Western Canadian heavy crude production, since we expect all heavy crude prices to be determined by the same set of logistic and competitive market factors. The benefits are computed relative to the scenario in which no pipeline projects other than the planned Enbridge expansions occur, and are based on the netback differences as illustrated in Figure 8. All benefit estimates are provided in billions of constant 2014 Canadian dollars.

Over the time period from 2021 through 2040 (20 years of Energy East operation), the aggregate benefits to the producing sector are estimated at C$663 billion if all projects move forward as assumed, and C$502 billion if Keystone XL, the Trans Mountain Expansion, and Northern Gateway are built. If only Energy East is built, then the aggregate benefits would be C$204 billion. The gross benefits to the producing sector are lower in the scenario in which only the Energy East pipeline is completed because the Energy East system alone would be insufficient to alleviate the capacity constraints faced by Western Canadian producers for an extended period.

The portion of the benefits attributable to Energy East has been computed in two ways. First, a simple allocation of the total benefit to the various projects based on their contribution to the total increase in capacity was computed. Over the same time period, the benefit attributable to Energy East would be C$217 billion if all projects are built. If only Energy East is built, then the aggregate benefits of C$204 billion would be fully attributable to Energy East.

The second calculation method to compute the benefits attributable to Energy East evaluates the incremental contribution of Energy East to the total benefits estimate, comparing a scenario with Energy East to a scenario without Energy East but otherwise the same. In the scenario in which only Energy East is built, the incremental calculation provides the same result as the allocation method (C$204 bilion). Energy East's contribution is estimated at C$161 billion when the scenario in which all projects are built is compared to the scenario in which all projects except Energy East (Scenario 2) are built.

Based on these two approches, the contribution of Energy East to the benefits created by the construction of the currently proposed projects is estimated at C$161 to C$217 billion if all projects are built. Details of the benefits calculation are provided in Appendix E.

Pipeline Scenario Implications

As the scenario analysis illustrates, provision of adequate takeaway capacity from Western Canada will require significant pipeline capacity to be constructed. If takeaway capacity is inadequate, significant price discounting for Western Canadian crude would be expected to prevail as the use of more costly alternative transport modes would be required, and the possibility of extraordinary discounts returns. The increases in crude oil netbacks attributable to the presence of adequate pipeline capacity would result in large benefits to the Western Canadian producing sector.

Williston Basin

Williston Basin crude oils are light sweet crude oils. Like Western Canadian crudes, Williston Basin crude prices have been discounted because of a lack of pipeline capacity connecting the crude oil to refining markets that can consume it. Crude by rail has been filling the gap.

Energy East: Transport Williston Basin crudes east

Today, the major pipeline expansion projects from the Williston Basin region point south to the US Gulf Coast, a region that has declining demand for light sweet crude from other regions due to its own growing domestic tight oil production. Meanwhile, the East Coast of Canada and the United States can consume more North American-produced light sweet crude by replacing overseas imports. As a result, significant volumes of Williston Basin light sweet crude are moving east by rail, since there are no direct pipeline connections linking the Williston Basin to the East Coast at this time.

However, there are two proposed pipeline projects for moving Williston Basin crude oil eastward - Energy East and the Line 9 reversal. Both projects move crude oil to Eastern Canada. Assuming that light sweet crude oil supply in Energy East would exceed Eastern Canadian demand, then crude could also be loaded onto tankers on the East Coast. The most likely destination would be the geographically closest market that demands light sweet crude, the US East Coast. Compared with the cost of railing crude oil from the Williston Basin region to the US East Coast, we expect that costs to transport on Energy East will be lower (see Appendix D for IHS calculated cost assumptions) .

Part 3) Possible markets served by Energy East

The Energy East project provides advantageous access to new markets for Western Canadian crude oils relative to other proposed pipeline projects or methods such as rail; including Atlantic Canada, the US East Coast, Europe and India. The project also boosts capacity to reach the US Gulf Coast. We expect the Energy East pipeline would transport all crude types (light sweet, light sour, and heavy crude). This part of the report reviews crude oil markets available to the Energy East pipeline: Eastern Canada, US East Coast, US Gulf Coast, and Overseas (Europe and India).

The cost of transporting crude oil by Energy East is a critical assumption in estimating the financial advantage offered by Energy East to each possible market. Our analysis uses a combination of the illustrative committed tolls provided by TransCanada for Energy East's National Energy Board (NEB) application, along with IHS estimates for marine tanker and rail rates (see Appendix D, Table D1 for assumptions).

Eastern Canada

Eastern Canada is comprised of two sub regions, Quebec and Atlantic Canada. Quebec has two refineries, and Atlantic Canada also has two refineries. The region's total refining capacity is 815,700 b/d. Based on a combination of publicly reported information and IHS estimates, crude runs in the region are estimated at 692,000 b/d in 2014. Of that, IHS estimates that 71% was light sweet crude, 19% was light sour crudes, and the remaining 10% was heavy crude.

Eastern Canadian refineries must compete with foreign refiners, including refineries in the United States and Europe which can deliver refined products into their markets by tanker. This competition, combined with declining demand for refined petroleum products, has resulted in refinery closures. In 2010 Shell Canada closed its Montreal refinery. Imperial Oil's Dartmouth refinery was shuttered in 2013. The Come-by Chance refinery has been sold several times in the past decade, most recently in late 2014. Having access to North American crudes would improve the competiveness of Canada's Eastern refiners, since IHS estimates that crudes delivered through Energy East would be lower in cost than either imported crude oil or domestic supply delivered by tanker or rail.

More Cost Advantaged Access to North American Crude Supply

Growing volumes of crude produced in Canada and the United States are reducing Eastern Canada's historical dependence on foreign crude oil suppliers. In 2014, Eastern Canada imported 294,000 b/d of crude from offshore suppliers, with almost two thirds of that from the Organization of Petroleum

Exporting Countries (OPEC).[7] Over the next few years, we expect the large majority of these offshore imports to be replaced with North American production delivered by rail or marine tanker from the US Gulf Coast until adequate pipeline capacity is installed.

Energy East provides a more efficient method for delivering increasing volumes of North American crude oil to Eastern Canada. In the absence of the Energy East pipeline project, East Coast refiners would need to use higher cost rail or tanker deliveries from the US Gulf Coast to receive North American crude oil.

Improved Refining Economics

Energy East would deliver crude oil to Eastern Canadian refiners at a lower cost than alternatives (see Appendix D for assumptions). Lower cost crude oil would enable Eastern Canadian refiners to more effectively compete with refiners who deliver refined products into their markets from the US and Europe. The potential price advantage varies by crude quality:

- **Light Sweet Crudes.** Using our outlook for light sweet crude supply along with our transport assumptions, light sweet crudes in Saint John will cost about US$9.00 per barrel less than the price of equivalent crude oil delivered to Saint John by rail (see Appendix D for details).

- **Light Sour Crudes.** In 2014, the region imported roughly 130,000 b/d of offshore light sour crude. We expect that compared with foreign imports, North American produced light sour crudes delivered via Energy East would be lower cost. With the start-up of Energy East, in the short term, there are two primary mechanisms for replacing offshore imports of light sour crude.
    - **Substitution with light sweet.** Due to the cost advantage for processing North American light sweet crudes over light sour imports, we expect eastern Canadian light sour refiners will increase consumption of North American light sweet crude oil to the extent possible - until they hit operational constraints. Compared with today, this is expected to reduce light sour demand into Eastern Canada by about one half.
    - **Consumption of Western Canadian light sour crude**. Western Canada currently provides about 300,000 b/d of this crude type to other regions, mostly the US Midwest and Ontario. While we expect the traditional markets to continue to demand some of this type of crude, a portion of this supply could also flow to Eastern Canada on Energy East.

Even with these two mechanisms for replacing foreign light sour imports with domestic supplies, we anticipate some light sour offshore imports may still be processed. However, due to the cost advantage for processing domestic crudes compared with offshore supply, over time, we expect that

[7] Total foreign crude imports to Eastern Canada in 2014 were 294,000 b/d, of which 194,000 was supplied by OPEC. Top foreign crude suppliers include Saudi Arabia, Iraq, Algeria, and Angola.

the Eastern Canadian refiners could reduce dependence on foreign light sour crudes by investing to increase light sweet crude processing capabilities.

- **Heavy Crudes.** We expect that Eastern Canadian refiners will obtain heavy crudes at a lower cost than US Gulf Coast refiners (see Appendix D for details). Using our transportation cost assumptions, we expect the cost of heavy crude at Saint John to be about US$4 per barrel lower than for refiners on the US Gulf Coast. Recently, Eastern Canadian refiners have consumed approximately 50,000 b/d of heavy crude. However, the potential is greater. With Energy East providing ample supply, we expect consumption could approach 100,000 b/d. This assumes no changes to the existing refinery configurations.

US East Coast

The US East Coast has seven refineries that focus on fuels production, with a total of 1.2 MMb/d of refining capacity. In addition, several small facilities focus on lubricant and specialty product production. Of the 1.1 MMb/d of crude consumed in the region in 2014, IHS estimates that about 72% was light sweet crude, 12% was light sour crudes, and the remaining 16% was heavy crude. The refineries produce about half of the refined products demanded in the region with the rest received from other regions. Like Eastern Canada, refiners here are under competitive pressure from refiners in the other regions – US Gulf Coast, Europe, and Eastern Canada – who deliver refined products into their market.

Shifting Crude Supply

In 2014, 33% of the crude used in the region was from non-North American suppliers and 25% was from Canada and the remainder was produced in the United States. Most of the Canadian supply has come from offshore East Coast production. However, one refinery consumes in the range of 30,000 b/d of heavy crude from Western Canada (delivered by the Enbridge pipeline system to an inland refinery in Warren, Pennsylvania). With this one exception, Western Canadian crudes do not have pipeline access to this region.

Crude supply in the region is shifting towards North American crudes. In 2012, over 400,000 b/d of offshore light sweet imports were consumed in the region. By 2014, light sweet crude from the Williston Basin and the US Gulf coast had replaced over 60% of those offshore imports.

Energy East Delivers Crudes at Lower Cost than Tanker or Rail

Energy East is expected to deliver North American crude to the US East Coast at a lower cost than other options – rail directly from inland sources or tanker delivery from the US Gulf Coast. The cost advantage and volume varies by crude type.

- **Light Sweet Crudes**. From the marine terminal in Saint John, Energy East could export light sweet crude by tanker to the US East Coast. The most likely market for light crude delivery would be the US East Coast, since it is the geographically closest and therefore the most economic.

Using our transportation cost assumptions, we expect light sweet crudes delivered by tanker from Energy East will be about US$4.00 per barrel lower in cost than alternative supplies delivered to the US East Coast by rail (see Appendix D for details).

- **Heavy Crudes**. Using our transportation cost assumptions, we expect that heavy crudes delivered by Energy East and then loaded onto tanker at Saint John for shipment to the US East Coast would be about US$4.00 per barrel lower cost than at the US Gulf Coast (see Appendix D for details). The US East Coast region currently consumes about 175,000 b/d of heavy crude. With ample supply available from Energy East, we expect consumption of Western Canadian heavy crude could increase from 30,000 b/d in 2012 to over 100,000 b/d (this assumes no coker additions in the region).

US Gulf Coast

We estimate that the cost to deliver Western Canadian crude by Energy East from Saint John to the US Gulf Coast will be comparable with existing pipe-only options (see Appendix D for details). Tanker deliveries from Energy East to the US Gulf Coast are expected to be predominantly heavy crude.

The US Gulf Coast is the largest regional refining center in the US. The region's 51 refineries have a total capacity of 9.9 MMb/d (over half of total US capacity). In addition to supplying the local market with refined products, the US Gulf Coast transfers refined products to other regions of the US and exports products internationally. US Gulf Coast refiners are estimated to have consumed 8.3 MMb/d of crude oil in 2014, of the following crude types:

- **Heavy Crudes** – With 1.6 MMb/d of coking capacity, the Gulf Coast region has a strong appetite for heavy crude — consuming 2.3 MMb/d in 2014. However, based on the existing coker utilization rates there was some spare capacity in 2014 and we estimate that the ultimate potential for consuming heavy crude is even larger at 2.7 MMb/d.[8] Although still a large market, we expect total heavy crude demand growth to be limited due in part to increasing supplies of light crude from tight oil which is likely to discourage coker investments.

- **Light Sweet Crude** – The region currently consumes about 4.0 MMb/d of light sweet crude. Owing to rapid growth in domestic tight oil production, offshore imports have declined steeply (dropping from 1.7 MMb/d in 2010 to approximately 0.1 MMb/d in 2014). Given the growing volume of domestic light sweet crudes available in the region, we expect refiners will increase their consumption of light sweet crude oils to the extent possible.

[8] In 2014, the coker utilization on the US Gulf Coast was just over 82% (inputs to coking units were 1.3 MMb/d and downstream processing was 1.6 MMb/d), Source: US EIA. IHS estimates that increasing the coker utilization to 87% would increase demand for heavy crude oil by over 200,000 b/d.

- **Light Sour Crudes** – The US Gulf Coast consumed 2.0 MMb/d of light sour crude in 2014. Over half was produced domestically, with the rest imported. Given the availability of discounted domestic light sweet crude oil, we expect that a portion of the light sour demand will be substituted with light sweet crudes. Refiners will substitute light sweet for light sour until they hit operational and economic constraints.

Heavy Crude Opportunity

The US Gulf Coast had historically received modest volumes of Western Canadian crude oil— roughly 100,000 b/d in 2012 —through one pipeline connection (Pegasus pipeline), rail and barge. The amount of Western Canadian supply reaching the US Gulf Coast has grown from increased rail deliveries, the start-up of the Seaway pipeline reversal in 2013, and the US Gulf Coast pipeline in 2014. The new pipelines can deliver Western Canadian crudes from Cushing, Oklahoma to the US Gulf Coast. Deliveries of heavy crudes from Western Canada to the US Gulf Coast are estimated to have exceeded 200,000 b/d in 2014.

Despite growing availability of domestic light sweet crude oil in the US Gulf Coast, we do not expect the market size for Canadian heavy crude oil to be materially impacted. We expect coking refiners will continue to run heavy crude oils rather than US domestic light sweet crude oil. Consequently, the opportunity for Western Canada is to deliver heavy crudes, specifically bitumen blends.

Today, the US Gulf Coast imports heavy crude from Venezuela (1.0 MMb/d in 2014) and Mexico (0.7 MMb/d in 2014), with the rest coming from smaller suppliers including Colombia and Brazil. Increased access to Canadian bitumen blend offers an alternative to less certain supplies from Mexico and Venezuela. Although Mexico has historically been a large source of heavy crude oil to the US Gulf Coast, its production has been declining. Between 2005 and 2014, imports of Mexican heavy crude to the US declined by about half.[9] At the root of Mexico's production decline is the lack of capital investment and application of advanced technology. To reverse the decline, Mexico is now implementing legislation to allow international companies to directly participate in Mexico oil production. How successful these reforms will ultimately be is still uncertain. However, over the longer term the changes do increase the prospects for growth in Mexican oil production. US imports from Venezuela have also been in decline, and there is uncertainty surrounding future supply. Despite these challenges our outlook is for some Venezuelan production growth in the years ahead, reflecting the potential for foreign investment in Orinoco development.

Energy East can deliver crude oil to Saint John to be loaded into tanker for delivery to the US Gulf Coast. Energy East can reach all refiners on US Gulf Coast waterways, including refiners in the

[9] Mexican Maya imports in 2014 were 0.7 MMb/d compared with 1.3 MMb/d in 2005.

Eastern Gulf Coast and Louisiana regions that are not connected to pipelines. By the end of the next decade, we expect deliveries of Canadian heavy crude to the US Gulf Coast could exceed 1.1 MMb/d. At this point, compared with today, supply from other offshore suppliers (Mexico, Venezuela, and other Latin American countries) would be reduced to approximately 1.3 MMb/d (see Appendix D for details).

For Western Canadian heavy crude to gain this much market share, other heavy crude suppliers would need to reduce their market share. Our current outlook is that supply from Latin America to the US Gulf Coast will decline. As a result, the substitution of Latin American heavy barrels with Canadian happens naturally. However, even if Mexico, Venezuela, and other Latin American countries were to ultimately produce more heavy crude than our outlook, we would still expect Western Canada to maintain a similar market share on the US Gulf Coast due to its logistical advantage.

Overseas Markets

As illustrated in Figure 9, the closest attractive offshore crude markets to Canada's East Coast are Europe and India. In Europe, refining capacity is concentrated in the Northwest and the Mediterranean, while Indian refining capacity is concentrated on the country's coastal regions.

Figure 9: Europe and India are accessible from Eastern Canada

Since the exports from Energy East are expected to be primarily heavy crude, we have limited our analysis to this crude type. Based on the IHS outlook for bitumen blend supply growth, we expect that demand in North America, and supply sent to Asia (from the West Coast) could potentially absorb the incremental production until the end of the next decade. However, well before that, we expect that some Western Canadian crude would be delivered to Europe and India. For Europe, the transportation costs from Saint John to Europe are comparable to the cost to transport crude by tanker from Saint John to the US Gulf Coast. For India, Western Canadian supply would improve the diversity of crude oil supply for the country.

Europe

The region's 107 refineries have a combined capacity of 15.3 MMb/d. The region consumed about 11.6 MMb/d of crude in 2014. The majority of Europe's refining capacity is designed for light sweet and light sour crudes. Even so, historic runs of heavy crude are still considerable at 0.9 MMb/d, and are expected to grow in coming years. Heavy crude is mainly supplied from offshore. The major suppliers include Saudi Arabia, Mexico, and Venezuela.

The current demand for heavy crude is driven by 20 refineries that have a combined coking capacity of 0.5 MMb/d (less than one-third of the capacity on the US Gulf Coast). Coking refiners with the ability to receive crude by tanker are the best candidates for delivery of Western Canadian crude. Considering this sub-set of heavy crude refiners, we estimate that the ultimate potential for processing Western Canadian heavy crudes is between 0.3 and 0.4 MMb/d.

Energy East's terminal in Saint John is economically positioned for moving heavy crude to Europe. The cost to move crude by tanker from the Saint John terminal to Europe is comparable to or cheaper than shipping the crude oil to the US Gulf Coast. In addition, compared with other heavy crude suppliers to Europe, the distance between Saint John and Europe is 20% to 65% closer (see Appendix D for details).

India

India's 21 refineries have a combined reported capacity of 4.6 MMb/d. In 2014, consumption was estimated at 4.7 MMb/d of crude, with over half of the crude supplied from the Middle East. Unlike the other markets examined in this report, India's oil demand is growing. By 2030, crude demand is expected to increase by over 50%.

Currently, India's refining capacity is about 30% the size of Europe's. However the Indian refining industry has higher coking capacity (0.8 MMb/d). As a result, historic runs of heavy crude are relatively high at 1.4 MMb/d. This capacity could easily grow by roughly 0.5 MMb/d with the construction of new refining capacity that is needed to meet growing demand for refined products. Ideal candidates for receiving Western Canadian crude are coking refiners located on the West Coast (closest to Eastern Canada) that can receive crude by tanker. Considering this sub-set of heavy sour refiners, we expect the ultimate potential for processing Western Canadian heavy crudes in India could be as high as 0.3 MM b/d.

With India being more distant than other markets considered in this report, the transportation costs are higher than other regions. We expect the cost to move crude from Saint John to India would be roughly US$2.00 per barrel higher than tanker shipments to the US Gulf Coast (see Appendix D for details). From a cost of transport perspective, heavy crude suppliers from the Middle East have an obvious advantage since the distance between the west coast of India and Saint John is about seven times greater than the distance from Saudi Arabia.

India, like many other developing countries, is searching for the right balance between economics and security of supply. Compared with today, IHS estimates that India will need an additional 2.9 MMb/d of crude oil imports by 2030. With dependence on the Middle East expected to increase further, supply diversity is of growing importance. As a consequence, even considering the higher costs for transporting Western Canadian crudes to India, we expect some crude oil could be delivered to that market.

Appendix A – Crude Oil Terms Used in this Report

Oil Sands

In its natural state, raw bitumen is the consistency of peanut butter and cannot be transported in pipelines. Hence, oil sands are pipelined to market using two methods:

- **Synthetic Crude Oil (SCO)** – SCO is produced from bitumen via refinery conversion units that turn heavy hydrocarbons into lighter, more valuable components. These units are called upgraders. SCO resembles light, sweet crude oil, with API gravity typically greater than 30.
- **Bitumen blends** – To meet pipeline requirements, bitumen is diluted with lighter hydrocarbons. A refinery may need modifications to process large amounts of bitumen blends because they contain more heavy oil components than most crude oils. Bitumen blends typically have an API gravity of 22 (similar to other heavy crude oils like Mexican Maya). The most common bitumen blend is dilbit—short for diluted bitumen. Bitumen is most often diluted with a natural gas condensate to make dilbit. An illustrative blend is about 70 percent bitumen and 30 percent condensate. However SCO and other light crudes are also used.

Crude Oil Types

We use three categories to describe the quality of crude oils in this report:

- Light sweet – API gravity of 28 or higher and sulfur content less than 1%
- Light sour – API gravity of 28 or higher and sulfur content 1% or higher
- Heavy – API gravity is less than 28 API and all levels of sulfur

Appendix B - Supply

Western Canadian Supply Outlook

Western Canadian production is expected to continue growing from current levels, driven by tight oil and Canadian oil sands. Table B1 compares the IHS and CAPP outlooks.

Table B1: Western Canadian Supply Outlook: IHS Compared With CAPP (Thousand Barrels per Day)

	2015	2020	2025	2030
IHS (Q1 2015)	3,731	4,730	5,287	5,852
CAPP (2015)	3,995	4,922	5,467	6,058
Difference	-264	-193	-180	-205

Source: IHS, CAPP

The majority of Canadian oil sands growth will be bitumen blends, as we do not expect supply from SCO will grow due to weak upgrading economics. Alberta greenfield upgrading economics have become challenged by two factors — high costs and narrow heavy light crude price differentials. Both discourage investment in upgrading equipment.

Appendix C – Existing Markets and Export Capacity

Western Canadian Crude Price Discounts

Table C1 illustrates the historical level of price discount for Canadian heavy crudes compared with the US Gulf Coast. To calculate the discount, we adjusted the average price of Cold Lake Blend in Alberta to represent the cost at the US Gulf Coast (by adding the pipeline transportation cost to reach the US Gulf Coast, and subtracting the crude quality difference between Cold Lake Blend and Maya).

Table C1: Crude Price Difference Between Cold Lake Blend and Maya at the US Gulf Coast (USGC) (US Dollars per Barrel, nominal)

	2013		2014	
Maya, USGC	98.38		87.15	
Cold Lake Blend, USGC	81.59	*	80.87	**
Difference	16.80		6.29	

**Adjusts Cold Lake Blend price assuming $12.06 per barrel transportation cost, and a quality difference of $1.23 per barrel (Cold Lake Blend minus Maya).*

***Adjusts Cold Lake Blend price assuming $12.12 per barrel transportation cost, and a quality difference of $1.16 per barrel (Cold Lake Blend minus Maya).*

Source: Platts, ©2014 by The McGraw-Hill Companies, Inc. (historical). Disclaimer: Historical oil price data are extracted or derived by IHS from Platts. All rights reserved. All liability for errors and omissions is hereby excluded by Platts and its sources, representations or warrenties are made by Platts or its sources concerning the data or conclusions to be drawn from it.

Table C2 shows the assumptions for calculating the revenues lost by Western Canadian producers due to price discounts in 2013 and 2014.

Table C2: Estimated Loss In Western Canadian Oil Revenues Resulting From Loss of Market Access

	2013		2014	
Key Assumptions	**High Transport Cost**	**Low Transport Cost**	**High Transport Cost**	**Low Transport Cost**
Amount of supply in Western Canada subject to lower prices*	3.1 MMb/d (43% light supply and 57% heavy supply)	3.1 MMb/d (43% light supply and 57% heavy supply)	3.4 MMb/d (40% light supply and 60% heavy supply)	3.4 MMb/d (40% light supply and 60% heavy supply)
Difference in price between Canadian Mixed Sweet (MSW) and Louisiana Light Sweet (LLS) at USGC**	Minus US$5/bbl	Minus US$10/bbl	Plus US$3/bbl	Minus US$1/bbl
Difference in price between Cold Lake Blend and Maya at USGC**	Minus US$17/bbl	Minus US$21/bbl	Minus US$6/bbl	Minus US$11/bbl
Total revenue (lost)/gained by Western Canadian producers	US$13.5 billion	US$18.6 billion	US$3.2 billion	US$9.0 billion

Source: IHS

*In both years, assumed that 300,000 b/d of Western Canadian supply was sent to Canada's west coast and received international pricing.

** Assumed a range of transport costs to reach USGC. Assumed no quality difference between MSW and LLS.

Western Canadian Crude Demand

Crude demand is expected to grow from the North West Redwater Partnership bitumen refinery (50,000 b/d) in 2017. Table C3 and Table C4 show refining capacity and estimated crude consumption in 2014.

Table C3: Western Canadian Refining Capacity 2014

Refinery	Nameplate Capacity (Thousand B/D)	Refinery Type
Chevron Canada Ltd. - North Burnaby	54.7	Cracking
Husky Energy - Prince George	12.0	Cracking
Imperial Oil Ltd. – Strathcona	189.0	Cracking
Suncor Energy Inc. – Edmonton	142.0	Coking
Shell Canada Ltd. - Scotford	100.0	Resid/Hydrocracking
Husky Energy - Lloydminster	29.1	Topping
Consumers' Co-op Refineries Ltd. - Regina	135.2	Coking
Moose Jaw Refinery - Moose Jaw	16.9	Topping
Total refining capacity in Western Canada	678.9	

Source: CAPP - Statistical Handbook (April 2015)

Notes: Western Canada includes the provinces of British Columbia, Alberta, Saskatchewan and Manitoba

Table C4: Western Canadian Crude Consumption 2014

Crude Type	Consumption (Thousand B/D)
Light Sweet	286
Light Sour	85
Heavy Sour	185
Total Crude Consumed in Western Canada	556

Source: IHS, Statistics Canada

Notes: Western Canada includes the provinces of British Columbia, Alberta, Saskatchewan and Manitoba

Proposed Pipeline Projects from Western Canada

Table C5 shows a list of new pipelines proposed to increase crude export capacity from Western Canada. In addition to the total capacity we have included our estimate of capacity from Western Canada (effective capacity removes capacity needed to transport Williston Basin crudes).

Table C5: Western Canadian Proposed Export Capacity

	Total Capacity (Thousand B/D)	IHS Estimated Capacity from Western Canada*	Assumed In-Service-Date
Enbridge mainline expansions	600	375**	2015-2017
TransCanada Keystone XL	830	730***	2019
Kinder Morgan Trans Mountain expansion	590	590	2018
TransCanada Energy East	1,100	900****	2020
Enbridge Northern Gateway	525	525	2021
Total	3,645	3,320	

Source: IHS

* Keystone XL, Enbridge mainline and Energy East total capacities have been adjusted to account for Williston Bas crude receipts.

**Although Enbridge mainline expansions are larger, we remove 225,000 b/d of the planned capacity to account for Sandpiper start-up (since this removes capacity for Western Canadian crudes).

***For Keystone XL, we assume 100,000 b/d of capacity is used to transport Williston Basin crudes.

****For Energy East, we assume 200,000 b/d of capacity is used to transport Williston Basin crudes delivered to Cromer.

Appendix D –Possible Markets from Energy East

This section will cover our assumptions for Western Canadian crude oil markets that are possible via Energy East, including Eastern Canada, US East Coast, US Gulf Coast and overseas markets – India and Europe. Crude transported by Energy East can be loaded into tankers at a terminal in Quebec or in Saint John.

Table D1 outlines our crude oil transportation assumptions for Eastern Canada and US East Coast. Our analysis uses a combination of the illustrative committed tolls provided by TransCanada for Energy East as part of the NEB application, as well as IHS estimates for marine tanker and rail rates.

Table D1: Crude Oil Transportation Costs

Mode of Transport	Origin ---> Destination	Transportation Costs (Value in 2021 in Constant 2014 US Dollars per Barrel, rounded)
Energy East - Tanker	Saint John ---> US Gulf Coast	US$2.00 per barrel – Source: IHS Tanker model. Assuming VLCC from Saint John to the USGC and including appropriate costs for lightering, fees, etc.
Energy East - Tanker	Saint John ---> East Coast	US$1.30 per barrel – Source: IHS Tanker model. Assuming VLCC from Saint John to the US East Coast (Philadelphia) and including appropriate costs for lightering, fees, etc.
Energy East - Pipeline	Alberta ---> Quebec/Montreal	US$5.65 per barrel (C$7.02 nominal) –Based on indicative tolls provided by TransCanada for Energy East: 20 year term rate between Hardisty and Quebec. Toll estimates rounded. Canadian dollar conversion rate assumed at 0.911 C$/US$.
Energy East - Pipeline	Alberta ---> Saint John	US$6.95 per barrel (C$8.60 nominal) – Based on indicative tolls provided by TransCanada for Energy East: 20 year term rate between Hardisty and Saint John. Toll estimates rounded. Canadian dollar conversion rate assumed at 0.911 C$/US$.
Rail	Williston Basin ---> Saint John Williston Basin ---> PADD 1	US$16.05 and US$12.20 per barrel, respectively – Source: IHS. Estimated total costs including rail on-loading, car lease, transportation, and offloading.

Source: IHS

Eastern Canada

Today, most of Eastern Canadian crude oil supply comes from offshore. The region's refiners are geared for light crudes as shown in Table D2 and Table D3. Table D4 shows the split of domestic and offshore crude supply.

Table D2: Eastern Canadian Refining Capacity 2014		
Refinery	**Nameplate Capacity (Thousand B/D)**	**Refinery Type**
Valero Energy Inc. - Levis (Saint Romuald)	265.0	Cracking
Suncor Energy Inc. - Montreal	137.0	Cracking
Irving Oil Ltd. - Saint John	298.8	Cracking
North Atlantic Refining Ltd. - Come By Chance**	114.9	Cracking
Total refining capacity in Eastern Canada	815.7	

Source: CAPP - Statistical Handbook (April 2015)

*Eastern Canada includes the provinces of Quebec, Nova Scotia, Prince Edward Island New Brunswick and Newfoundland.

**Come by Chance would not have direct access to Energy East. Supply would need to come by tanker from Saint John and as a consequence the cost of crude from Energy East would be higher than other refineries.

Table D3: Eastern Canadian Crude Consumption		
Crude Type	**2013 Consumption (Thousand B/D)**	**2014 Consumption (Thousand B/D)**
Light Sweet	550	494
Light Sour	186	131
Heavy	43	67
Total Crude Consumed in Eastern Canada	779	692

Source: IHS, Statistics Canada

Notes: Eastern Canada includes the provinces of Quebec, Nova Scotia Prince Edward Island, New Brunswick and Newfoundland.

Table D4: Eastern Canadian Crude Consumption by Origin (2014)	
Crude Type	**Consumption (Thousand B/D)**
Foreign Offshore Imports	294
Imports from US	288
Canadian Domestic	110
Total Crude Consumed in Eastern Canada	692

Source: IHS, Statistics Canada

Notes: Eastern Canada includes the provinces of Quebec, Nova Scotia Prince Edward Island, New Brunswick and Newfoundland.

The Energy East pipeline provides a lower cost route for supply of light and heavy crude oil to Eastern Canadian refiners than the rail alternative. The Enbridge Line 9 reversal project brings Western supplies to Ontario and Montreal, but does not bring Western supplies to Levis (St. Romuald) or Saint John.

Eastern Canadian Price Advantage for Light Crudes Delivered Through Energy East.

In the absence of crude oil delivered by the Energy East pipeline, East Coast refiners would be expected to consume a similar volume of crude oil from the Williston Basin and Western Canada delivered by rail car. We estimate that the cost of delivering crude oil from the Williston Basin or Western Canada to Saint John is approximately US$16.00 per barrel. If Energy East were available, we assume the transportation fees to move crude between the Williston Basin or Alberta and Saint John would be US$6.95 per barrel (see Table D1 for cost assumptions). Consequently, compared with rail, Eastern Canadian refiners will have a price advantage for receiving crude oil on Energy East - equivalent to the difference between the cost of rail and the cost of pipeline, or roughly US$9.00 per barrel.[10]

Eastern Canadian Price Advantage for Heavy Crudes Delivered Through Energy East.

The price of heavy crude in Alberta is determined by the price necessary for the last barrel produced to clear the market. We expect that that pipeline capacity will exceed Western Canada supply for export after 2017 if all projects proceed as planned. At this time, heavy crude oil prices in Alberta would be based on US Gulf Coast prices minus pipeline transportation costs. At the same time, Eastern Canada prices would reflect pricing in Alberta, plus transportation costs (see Table D1 for cost assumptions).

- **Price in Alberta** – Assuming the price in the US Gulf Coast for heavy crude oil to be US$100 per barrel, the price in Alberta would be the US Gulf Coast price minus the estimated transportation cost of US$11.00 per barrel, or US$89.00 per barrel.
- **Price in Saint John** – Assuming Energy East were available, the heavy crude price in Saint John would be the price in Alberta (US$89.00 per barrel) plus transportation cost of US$7.00 per barrel or US$96.00 per barrel (compared with the price of $100 per barrel on the US Gulf Coast).

As a result, for heavy crudes, Eastern Canadian refiners at Saint John would be able to purchase crudes for US$4.00 per barrel lower than the crudes are priced on the US Gulf Coast. Using our assumption that the transportation cost from Alberta to Quebec would be lower than to Saint John (US$5.65 per barrel as compared to US$7.00 per barrel), the cost advantage in Quebec would be more than US$1.00 per barrel greater.

[10] We calculated the difference between the rail cost of $16.00 per barrel and the pipeline fee of $7.00 per barrel.

US East Coast

Today, US East Coast crude supply comes from Canada, offshore, and domestic sources. The region's refiners are mostly geared for light crudes as shown in Table D5 and Table D6. Table D7 shows domestic crude supply compared with offshore.

Table D5: US East Coast Refining Capacity 2015*

Refinery	Nameplate Capacity (Thousand B/D)	Refinery Type
Delaware City Refining Co LLC – Delaware	182.2	Coking
Phillips 66 Company - Linden	238.0	Cracking
Paulsboro Refining Co LLC - Paulsboro	160.0	Coking
Axeon Specialty Products LLC - Paulsboro	38.0	Asphalt
Philadelphia Energy Solutions - Philadelphia	335.0	Cracking
Monroe Energy LLC - Trainer	185.0	Cracking
United Refining Co - Warren	65.0	Cracking
Total refining capacity in US East Coast	1,203.2	

Source: EIA

* There are two other inland refiners that are not included as we do not anticipate they would have access to crude from tanker deliveries via Energy East: American Refining Group (Bradford) with a 11,000 b/d topping/lube refinery and Ergon West Virginia Inc (Newell) with a 22,300 b/d topping/lube refinery. Also, 32,000 b/d of capacity is reported as "Idle" at the Axeon facility and is not included.

Table D6: US East Coast Crude Consumption By Crude Type 2014

Crude Type	Consumption (Thousand B/D)
Light Sweet / Segregated Condensate	785
Light Sour	127
Heavy	176
Total Crude Consumed in US East Coast	1,088

Source: IHS, EIA

Notes: Eastern Canada includes the provinces of Quebec, Nova Scotia Prince Edward Island, New Brunswick and Newfoundland.

Table D7:US East Coast Crude Consumption By Origin 2014	
Crude Type	**Consumption (Thousand B/D)**
Canada	283
Foreign Offshore Imports	359
US Domestic Supply	447
Total Crude Consumed in US East Coast	1,088

Source: IHS, EIA

Using the IHS tanker model, we estimate the cost for moving crude to the US East Coast from Saint John via tanker at about US$1.30 per barrel (2021 basis, including appropriate costs for lightering, fees, etc.). This reduces the cost advantage for US East Coast refiners (as compared to Eastern Canadian Refiners) by the same amount. Consequently, light sweet crude costs on the US East Coast are expected to be US$4.00 per barrel lower than the alternative of rail deliveries from the Williston Basin. By the same logic, US East Coast refiners would receive heavy crude oil at US$4.00 per barrel lower than refiners on the US Gulf Coast.

US Gulf Coast

The US Gulf Coast refining industry is complex and consumes all crude types, as shown in Table D8 and Table D9. Table D10 shows domestic crude supply compared with offshore and Canadian imports.

Table D8: US Gulf Coast Refining Configurations 2015		
Refinery	**Capacity (Thousand B/D)**	**Percent of Total**
Coking	7,401	80%
Cracking	1,459	16%
Hydroskimming	154	2%
Topping/Asphalt	203	2%
Total	9,217	

Source: EIA

Table D9: US Gulf Coast Crude Consumption By Type 2014	
Crude Type	**Consumption (Thousand B/D)**
Light Sweet / Segregated Condensate	3,980
Light Sour	2,031
Heavy	2,253
Total Crude Consumed in US Gulf Coast	8,264

Source: IHS, EIA

Table D10: US Gulf Coast Crude Consumption By Origin 2014	
Crude Type	**Consumption (Thousand B/D)**
Canada	259
Foreign Offshore Imports	2,993
US Domestic Supply	5,012
Total Crude Consumed in US Gulf Coast	8,264

Source: IHS, EIA

The US Gulf Coast is a large heavy crude refining center, and because we expect coking refiners to make a greater profit running heavy crude oils, we do not expect the market size for heavy crude to be materially impacted by the surplus of light sweet crude oil in North America. Today Mexico and Venezuela are the largest suppliers. We expect US imports of Mexican and Venezuela crude will decline over our forecast period while at the same time Canadian heavy crude supply will increase (see Table D11).

Table D11: Outlook for US Gulf Coast Future Heavy Crude Oil Supply by Origin		
Crude Type	**2014 Supply (Thousand B/D)**	**2030 Supply (Thousand B/D)**
Canada	238	1,100
Mexico	658	195
Venezuela	1,026	647
Other	332	429
Total Heavy Crude Consumed in USGC	2,253	2,371

Source: IHS, EIA

Europe

Once Energy East is in service, Western Canadian crude could be sent via tanker to Europe. Although European refiners are mostly geared to lighter crudes, some coking capacity exists, enabling heavy crude to be consumed, as shown in Table D12 and Table D13.

Table D12: European Refinery Configurations 2015		
Refinery	**Capacity (Thousand B/D)**	**Percent of Total**
Coking	2,988	20%
Cracking	9,240	61%
Hydroskimming	1,673	11%
Topping/Asphalt	1,368	9%
Total	15,268	100%

Source: Oil and Gas Journal refining survey

Table D13: European Crude Consumption By Type 2014	
Crude Type	**Consumption (Million B/D)**
Light Sweet	5.1
Light Sour	5.6
Heavy	0.9
Total Crude Consumed in Europe	11.6

Source: IHS

Compared with other heavy crude suppliers to Europe, the distance between Saint John and Europe is 19% to 64% closer (see Table D14).

Our analysis shows that the cost of delivering crude from Saint John by tanker to Europe would be comparable to, and likely less than, the cost for transporting crude from Saint John to the US Gulf Coast (see Table D15).

Table D14: Marine Distances			
From	**To**	**Distance (Nautical Miles)**	**Saint John Percent Distance Closer to Europe**
Saint John, NB	Cartagena, Spain	3,218	
Cayo Arcas, Mexico	Cartagena, Spain	5,019	56%
Puerto La Cruz, Venezuela	Cartagena, Spain	3,836	19%
Saint John, NB	Rotterdam, Netherlands	3,071	
Cayo Arcas, Mexico	Rotterdam, Netherlands	5,047	64%
Puerto La Cruz, Venezuela	Rotterdam, Netherlands	4,203	37%

Source: Worldscale Association

Table D15: Marine Freight Summary to Europe (2021)*				
From	**To**	**Tanker Size**	**Freight (Constant 2014 US$/B)**	**USGC Delta (Constant 2014 US$/B)**
Saint John, NB	Houston, TX	VLCC	2.01	--
Saint John, NB	Rotterdam, Netherlands	VLCC	1.61	(0.39)
Saint John, NB	Cartagena, Spain	VLCC	1.74	(0.27)

Source: IHS

*Additional transportation-related costs are not included. Costs in 2021 were used as they better represent longer-term expectations.
The USGC estimate assumes that the tanker movement is entirely within the emissions control area (ECA) and therefore requires lower sulfur fuel and has higher fuel prices (as compared to Europe-destined shipments).

India

In addition to European markets, Canadian crude could also be exported from Saint John to India. Compared with Europe, refineries in India are more complex. Table D16 and D17 show the refining capacity and crude types consumed.

Table D16: India Refinery Configurations 2015

Refinery	Capacity (Thousand B/D)	Percent of Total
Coking	3,056	67%
Cracking	1,304	29%
Hydroskimming	22	0%
Topping/Asphalt	194	4%
Total	4,576	100%

Source: Oil and Gas Journal refining survey

Table D17: India Crude Consumption By Type 2014

Crude Type	Consumption (Million B/D)
Light Sweet	1.4
Light Sour	1.9
Heavy	1.4
Total	4.7

Source: IHS

Our analysis suggests that, on average, delivering crude from Saint John by tanker to India would be roughly US$2.00 more per barrel than the cost for transporting crude to the US Gulf Coast (see Table D18).

Table D18: Marine Freight Summary to India (2021)*

From	To	Tanker Size	Freight (Constant 2014 US$/B)	USGC Delta (Constant 2014 US$/B)
Saint John, NB	Houston, TX	VLCC	2.01	--
Saint John, NB	Jamnagar, India	VLCC**	4.00	(1.99)

Source: IHS

*Additional transportation-related costs are not included. Costs in 2021 were used as they better represent the longer-term prices (current prices are below this level). The USGC estimate assumes that the tanker movement is entirely within the emissions control area (ECA) and therefore requires lower sulfur fuel and has higher fuel prices (as compared to Europe-destined shipments).

**Assumes Cape of Good Hope route laden, Suez Canal in ballast

Appendix E – Calculation of Gross Benefits to the Producing Sector (Billion Constant 2014 Canadian $)

CALCULATION OF GROSS BENEFITS TO PRODUCING SECTOR

(Billion Constant 2014 Canadian $)

Benefit computed for Western Canadian heavy crude production relative to reference case of no projects constructed other than ENB increases

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
US/Cdn $ Exchange Rate	0.905	0.911	0.911	0.914	0.912	0.909	0.907	0.903	0.901	0.897	0.893
Heavy Crude Oil Supply (MMb/d)	3,049	3,224	3,386	3,484	3,608	3,716	3,808	3,947	4,091	4,229	4,372
Cold Lake Blend Netback Prices (Constant 2014 Cdn$)											
Reference Case	62.19	54.56	56.02	63.48	73.34	80.72	83.70	84.78	74.31	75.03	74.86
Only Energy East	62.19	54.56	64.97	72.73	83.01	90.74	83.70	84.78	85.76	86.53	86.41
Keystone XL+TMX+Gateway	71.15	63.36	64.97	72.73	83.01	90.74	93.95	95.22	96.30	97.19	97.17
All Projects	71.15	63.36	64.97	72.73	83.01	90.74	93.95	95.22	96.30	97.19	97.17
Gross Benefit Relative to Reference Case											
Only Energy East	0.0	0.0	11.1	11.8	12.7	13.6	0.0	0.0	17.1	17.8	18.4
Keystone XL+TMX+Gateway	10.0	10.4	11.1	11.8	12.7	13.6	14.3	15.0	32.8	34.3	35.6
All Projects	10.0	10.4	11.1	11.8	12.7	13.6	14.3	15.0	32.8	34.3	35.6
Allocated Benefit Attributable to Energy East											
Only Energy East	0.0	0.0	11.1	11.8	12.7	13.6	0.0	0.0	17.1	17.8	18.4
Keystone XL+TMX+Gateway	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
All Projects	0.0	0.0	3.6	3.9	4.2	4.5	4.7	4.9	10.8	11.2	11.7
Incremental Benefit Attributable to Energy East											
Only Energy East	0.0	0.0	11.1	11.8	12.7	13.6	0.0	0.0	17.1	17.8	18.4
All Projects	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2021-2040
US/Cdn $ Exchange Rate	0.890	0.888	0.886	0.885	0.884	0.884	0.884	0.884	0.884	0.884	0.884	
Heavy Crude Oil Supply (MMb/d)	4,515	4,658	4,802	4,947	5,096	5,241	5,377	5,513	5,649	5,792	5,935	
Cold Lake Blend Netback Prices (Constant 2014 Cdn$)												
Reference Case	74.43	73.32	72.17	72.31	72.36	73.02	73.04	73.48	74.45	76.45	77.79	
Only Energy East	86.02	84.93	83.80	83.96	84.02	73.02	73.04	73.48	74.45	76.45	77.79	
Keystone XL+TMX+Gateway	96.86	95.84	94.77	95.01	84.02	84.68	84.70	85.15	86.12	88.11	89.45	
All Projects	96.86	95.84	94.77	95.01	95.15	95.91	96.00	96.53	97.60	99.74	101.20	
Gross Benefit Relative to Reference Case												
Only Energy East	19.1	19.7	20.4	21.0	21.7	0.0	0.0	0.0	0.0	0.0	0.0	204
Keystone XL+TMX+Gateway	37.0	38.3	39.7	41.0	21.7	22.3	23.0	23.5	24.1	24.7	25.3	502
All Projects	37.0	38.3	39.7	41.0	42.4	43.8	45.2	46.4	47.7	49.2	50.9	663
Allocated Benefit Attributable to Energy East												
Only Energy East	19.1	19.7	20.4	21.0	21.7	0.0	0.0	0.0	0.0	0.0	0.0	204
Keystone XL+TMX+Gateway	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
All Projects	12.1	12.6	13.0	13.4	13.9	14.4	14.8	15.2	15.7	16.1	16.7	217
Incremental Benefit Attributable to Energy East												
Only Energy East	19.1	19.7	20.4	21.0	21.7	0.0	0.0	0.0	0.0	0.0	0.0	204
All Projects	0.0	0.0	0.0	0.0	20.7	21.5	22.2	22.9	23.7	24.6	25.5	161

Calculation of Gross Benefits to the Producing Sector (Billion Constant 2014 US $)

CALCULATION OF GROSS BENEFITS TO PRODUCING SECTOR

(Billion Constant 2014 US $)

Benefit computed for Western Canadian heavy crude production relative to reference case of no projects constructed other than ENB increases

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Heavy Crude Oil Supply (MMb/d)	3,049	3,224	3,386	3,484	3,608	3,716	3,808	3,947	4,091	4,229	4,372
Cold Lake Blend Netback Prices (Constant 2014 US$)											
Reference Case	56.31	49.70	51.01	58.02	66.89	73.36	75.88	76.55	66.94	67.28	66.81
Only Energy East	56.31	49.70	59.16	66.47	75.70	82.46	75.88	76.55	77.25	77.59	77.12
Keystone XL+TMX+Gateway	64.43	57.71	59.16	66.47	75.70	82.46	85.17	85.97	86.75	87.15	86.72
All Projects	64.43	57.71	59.16	66.47	75.70	82.46	85.17	85.97	86.75	87.15	86.72
Gross Benefit Relative to Reference Case											
Only Energy East	0.0	0.0	10.1	10.8	11.6	12.4	0.0	0.0	15.4	16.0	16.4
Keystone XL+TMX+Gateway	9.0	9.5	10.1	10.8	11.6	12.4	12.9	13.6	29.6	30.8	31.8
All Projects	9.0	9.5	10.1	10.8	11.6	12.4	12.9	13.6	29.6	30.8	31.8
Allocated Benefit Attributable to Energy East											
Only Energy East	0.0	0.0	10.1	10.8	11.6	12.4	0.0	0.0	15.4	16.0	16.4
Keystone XL+TMX+Gateway	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
All Projects	0.0	0.0	3.3	3.5	3.8	4.1	4.2	4.5	9.7	10.1	10.4
Incremental Benefit Attributable to Energy East											
Only Energy East	0.0	0.0	10.1	10.8	11.6	12.4	0.0	0.0	15.4	16.0	16.4
All Projects	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2021-2040
Heavy Crude Oil Supply (MMb/d)	4,515	4,658	4,802	4,947	5,096	5,241	5,377	5,513	5,649	5,792	5,935	
Cold Lake Blend Netback Prices (Constant 2014 US$)												
Reference Case	66.21	65.07	63.95	64.00	64.00	64.55	64.55	64.94	65.80	67.56	68.75	
Only Energy East	76.52	75.38	74.25	74.31	74.31	64.55	64.55	64.94	65.80	67.56	68.75	
Keystone XL+TMX+Gateway	86.16	85.06	83.97	84.09	74.31	74.85	74.85	75.25	76.11	77.87	79.06	
All Projects	86.16	85.06	83.97	84.09	84.15	84.78	84.84	85.31	86.26	88.14	89.43	
Gross Benefit Relative to Reference Case												
Only Energy East	17.0	17.5	18.1	18.6	19.2	0.0	0.0	0.0	0.0	0.0	0.0	183
Keystone XL+TMX+Gateway	32.9	34.0	35.2	36.3	19.2	19.7	20.3	20.7	21.3	21.8	22.4	447
All Projects	32.9	34.0	35.2	36.3	37.5	38.7	39.9	41.0	42.2	43.5	44.9	590
Allocated Benefit Attributable to Energy East												
Only Energy East	17.0	17.5	18.1	18.6	19.2	0.0	0.0	0.0	0.0	0.0	0.0	183
Keystone XL+TMX+Gateway	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
All Projects	10.8	11.1	11.5	11.9	12.3	12.7	13.1	13.4	13.8	14.3	14.7	193
Incremental Benefit Attributable to Energy East												
Only Energy East	17.0	17.5	18.1	18.6	19.2	0.0	0.0	0.0	0.0	0.0	0.0	183
All Projects	0.0	0.0	0.0	0.0	18.3	19.0	19.7	20.2	20.9	21.7	22.5	142

Appendix F – Resume of William J. Sanderson

Education

B.S. Chemical Engineering from Montana State University in 1976

Current Position

Vice President in IHS Global Inc.'s Oil Markets and Downstream Energy Research and Consulting organization

Work Experience

Mr. Sanderson is a Vice President in the Oil Markets and Downstream Energy Research and Consulting organization for IHS. He is the former President and CEO of the consulting firm of Purvin & Gertz. Purvin & Gertz was an independent energy consulting firm serving the petroleum, petrochemical, natural gas and gas liquids industries that was acquired by IHS Global, Inc. in November 2011.

Mr. Sanderson has broad experience in the commercial, strategic and technical aspects of the downstream petroleum industry. His range of consulting activities include directing the firm's crude oil valuation services, petroleum market analysis including pricing studies for both crude oil and refined products, merger and acquisition assistance for petroleum-related businesses, strategic business analysis, refinery feasibility and planning studies and expert testimony in legal and regulatory matters.

After graduating from Montana State University with a Bachelor of Science degree in Chemical Engineering in 1976, Mr. Sanderson was employed by the UOP Process Division, a refinery technology licensor. In 1983, Mr. Sanderson joined the Champlin Petroleum Company (now Valero Energy Corporation) in the Wilmington, California refinery where he held a variety of technical and commercial management positions including Manager of Process Engineering and Manager of Economics and Planning.

In 1988, Mr. Sanderson joined the Long Beach, California office of Purvin & Gertz, where he consulted on a variety of petroleum-related topics for the firm's West Coast and Asia Pacific clients. In 1996, he was elected Vice President and was transferred to the firm's London office to direct Purvin & Gertz' consulting activities in Europe, Africa and the Middle East. In 1997, he was elected to the firm's Board of Directors. In 1999, he was transferred from London to the Houston office. He was elected President and CEO of the firm in 2000. He assumed the global leadership role in the IHS Downstream Energy Research and Consulting organization when Purvin & Gertz was acquired by IHS. He served in that capacity until May 2014. Mr. Sanderson currently is a Vice President of IHS providing thought leadership on specific topics.

Representative Major Consulting Experience

Crude Oil Valuation Services

Mr. Sanderson formerly directed the firm's crude oil valuation and pipeline quality bank consulting activities. He has directed the development and administration of crude oil pipeline quality banks for systems in the United States, North and South America, Africa, Europe and the Middle East. He has directed the evaluation of numerous crude oil and condensate streams for clients ranging from crude oil producers to petroleum refiners and trading companies. He has directed studies of the market values of many types of crude oils from the North Sea, Africa, Central Europe and the FSU, North and South America, and the Far East. Examples of Mr. Sanderson's representative experience include:

- Mr. Sanderson has directed numerous market studies for high total acid number (TAN) crudes produced in the North Sea, West Africa, South America and the Asia Pacific regions. The studies have involved an assessment of the market value of the crude, documentation of processing issues, determination of optimum markets, identification of likely customers, and recommendations regarding marketing strategies to maximize the value of high TAN crudes.
- Mr. Sanderson performed a market study and crude oil valuation of a major crude oil stream produced in the Caspian Sea region assessing the crude oil value in specific markets and evaluating netback values using numerous transportation alternatives.
- Mr. Sanderson assisted an independent producer value a new crude oil stream produced in offshore India. He also assisted the producer negotiate a term crude oil sales contract with the Government of India.
- On behalf of the producers, Mr. Sanderson directed the development of quality bank methodology and procedures for a major Latin American crude oil pipeline system.
- On behalf of the producers and the Ministry of Energy for the host country, Mr. Sanderson directed the development of the pipeline quality bank system for the addition of a new crude oil stream into an existing pipeline system in the Middle East.
- Mr. Sanderson assisted an existing West African crude oil producer and pipeline operator develop and negotiate quality bank procedures with the producer of a new production field to be commingled with existing production.

Petroleum Market Analysis

The Downstream organization continually monitors and evaluates the supply/demand balances, trading patterns, and pricing relationships of crude oil and petroleum products in the major world markets. Mr. Sanderson has directed the development and continuing analysis of petroleum pricing trends and long-term price forecasts on the U.S. West Coast, the U.S. East Coast and Europe including the pricing of reformulated fuels in these markets. He has provided specific market and pricing analysis in all regions of the U.S., Europe, Asia and Latin America including the Caribbean and South American regions for a variety of clients.

Strategic Business Analysis

Mr. Sanderson has conducted a number of strategic studies for new business ventures and major projects as well as strategic assessments of existing operations for petroleum industry clients. Mr. Sanderson has analyzed the operation and future profitability of a number of refining and marketing facilities on behalf of both operating companies and financial institutions. On behalf of financial institutions, he has directed the independent evaluation of refinancing proposals for refining and retail marketing businesses. These evaluations have included an independent review of the company business plan, identification of likely strategic alternatives and independent analysis of the likely success of the proposed operation in view of future changes in the petroleum industry.

- Mr. Sanderson directed the review of the crude oil purchasing policies and procedures of a multi-refinery Latin American refining and distribution company. A detailed organizational plan was developed to implement the recommendations.
- He directed a strategic assessment of global opportunities in the petroleum transportation and terminaling business on behalf of a major international oil company. The strategic assessment resulted in the identification and prioritization of investment opportunities in a number of Asia Pacific countries.
- Mr. Sanderson has served as an advisor on energy policy concerning refining, crude oil supply and pricing and refined product pricing to government entities in Chile, Puerto Rico, Saudi Arabia and Kuwait.
- Mr. Sanderson has provided strategic business advice to a major North American independent refining and marketing company with major operations on the East Coast including analysis of new business opportunities and acquisitions in the refining and distribution sectors in North America and Europe, capital investment economics and benchmarking of the company's existing and future operations.

Mergers And Acquisitions

Mr. Sanderson has assisted clients involved in mergers and acquisitions of petroleum refining, transportation and retail marketing assets on behalf of both buyers and sellers. The acquisition assistance has included screening of potential assets, specific facility evaluations, direct participation in purchase negotiations and due diligence activities. The evaluations of refining assets have included the development of refinery yields, determination of specific crude oil and product pricing as well as the evaluation of other technical and commercial conditions necessary to develop realistic cash flow projections. He has analyzed and valued petroleum terminals, transportation operations and retail marketing operations. The evaluations performed include the analysis of business activities, earnings projections, the physical review of the facilities and the development of fair market values using cash flow, cost-based and market-based valuation methodologies. Some example assignments include:

- Mr. Sanderson directed the evaluation of major West Coast refining and retail marketing assets being sold as a result of a merger on behalf of a potential buyer. The assignment included a fair market valuation of the refinery and retail stations, physical inspection of the facilities and due diligence activities. The results of the analysis were presented to the purchaser's Board of Directors.

- He led the evaluation of a major refining complex in the People's Republic of China on behalf of a major integrated oil company. The evaluation included a fair market valuation, numerous site visits to the facility to assess the condition of the process equipment, assistance in the negotiation of the purchase and due diligence assistance.
- Mr. Sanderson conducted an analysis of an integrated regional European refining and marketing company on behalf of a potential purchaser. The analysis included the development of a fair market valuation of the company including the refining, distribution, retail marketing assets, pipeline operations and non-energy businesses.

Expert Testimony

Mr. Sanderson has provided expert testimony in the following legal and regulatory matters:

Golden Gate Petroleum v. Martinez Terminals Ltd. – 1990
Petroleum Terminal Losses
Superior Court of California, County of Contra Costa
Trial Testimony

City of Long Beach v. Signal Hill Terminal Corporation –1993
Petroleum Terminal Value
Deposition

Paramount Petroleum Corporation v. County of Los Angeles – 1995
Refinery Fair Market Value
Los Angeles County Tax Assessment Appeals Board

ARCO Products Company v. County of Los Angeles – 1996
Refinery Fair Market Value
Los Angeles County Tax Assessment Appeals Board

Ratheon-Catalytic, Inc. v. Gulf Chemical Corporation – 1998
Income Projection
Puerto Rico Chemical Facility
U.S. District Court – Puerto Rico District
No. 96-1541
Deposition – December, 1998

South Tahoe Public Utility District v. Tosco Corporation, et al.– 2001/2002
Ability to Distribute Ethanol-blended Gasoline in California
Superior Court of California, County of San Francisco
No. 999128
Deposition – June 2001
Trial Testimony – February 2002

Communities for a Better Environment v. Unocal, et al. – 2001
Distribution of Ethanol-blended Gasoline in California
Superior Court of California, City and County of San Francisco
No. 997013
Declaration – July 2001

Trans Alaska Pipeline System Quality Bank – 1993 through 2007
U.S. Federal Regulatory Commission
Docket Nos. OR89-2-000, et al.
Regulatory Commission of Alaska
Docket Nos. P-89-2, et al.
Written Testimony – 1994, 1996, 1999, 2000, 2002, 2003, 2007
Depositions – 2002, 2007
Oral Testimony – 2003, 2007

Crescenta Valley Water District v. ExxonMobil Corp., et al.
Distribution of Ethanol-blended Gasoline in California
United States District Court for the Southern District of New York
Case No. 07 Civ. 9453 (SAS)
Written Testimony – September 2010
Deposition – January 2011

Orange County Water District v. Unocal Corp., et al.
Distribution of Ethanol-blended Gasoline in California
United States District Court for the Southern District of New York
Case No. 05 Civ. 4968 (SAS)
Written Testimony – May 2011
Deposition – July 2011

City of Merced Redevelopment Agency v. ExxonMobil Corp., et al.
Distribution of Ethanol-blended Gasoline in California
United States District Court for the Southern District of New York
Case No. 08 Civ. 06306 (SAS)
Written Testimony – May 2011
Deposition – July 2011

City of Merced v. Chevron U.S.A., Inc., et al.
Distribution of Ethanol-blended Gasoline in California
Superior Court of California, County of Merced
Case No. 148451
Written Testimony – May 2011
Deposition – July 2011