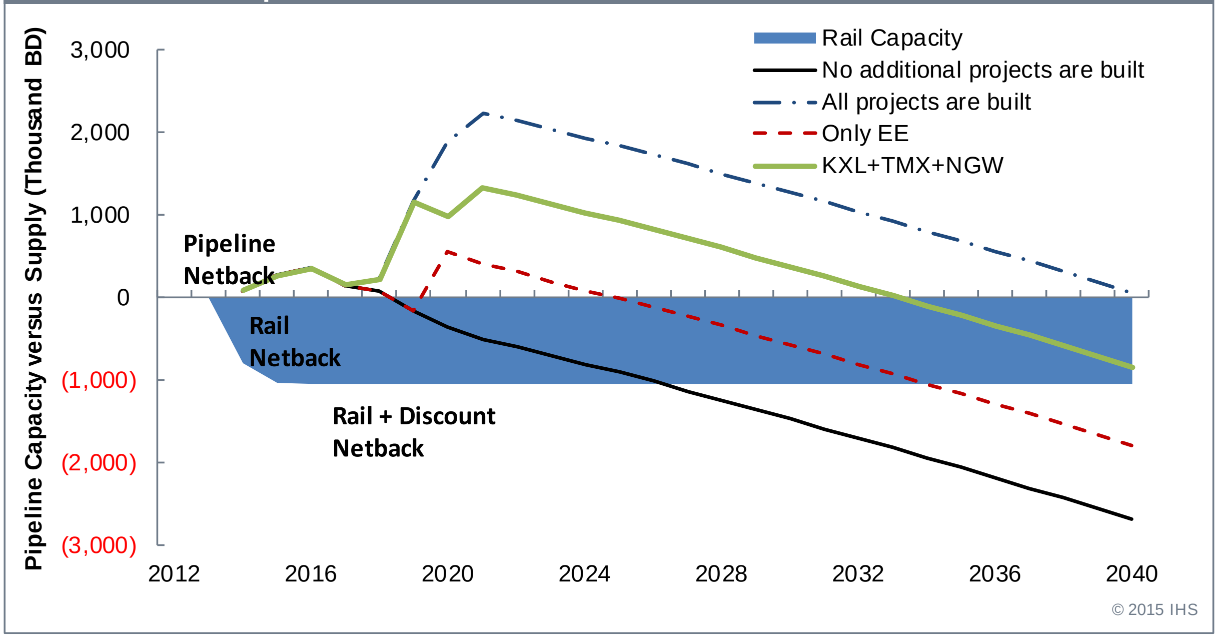
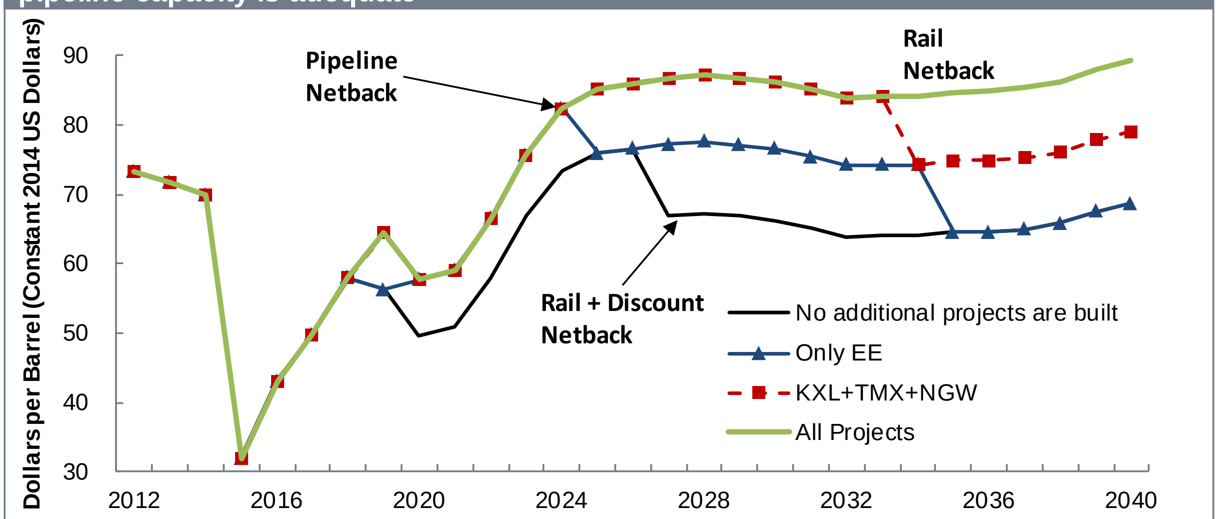
Figure 7: Pipeline capacity balances are expected to determine the mechanism setting crude oil netback prices



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.

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

Key Assumptions	2013 High Transport Cost	2013 Low Transport Cost	2014 High Transport Cost	2014 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