MARKET PROSPECTS

AND

BENEFITS ANALYSIS

OF THE

TRANS MOUNTAIN EXPANSION PROJECT

FOR

TRANS MOUNTAIN PIPELINE (ULC)

September 2015

MUSE STANCIL

15455 Dallas Parkway
Suite 350
Addison, TX 75001-4690
Phone: 214-954-4455
Fax: 214-954-1521

One City Centre
1021 Main Street, Suite 1560
Houston, TX 77002
Phone: 713-890-1182
Fax: 214-954-1521

Tower 42
25 Old Broad Street
London EC2N 1HN
United Kingdom
Phone: 44-0-207-374-8994

Level 58 Republic Plaza
9 Raffles Place
Singapore 048619
Phone: 65-6832-1341
Fax: 65-6832-1491

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INTRODUCTION

Trans Mountain Pipeline ULC (Trans Mountain) has proposed an expansion of its existing oil pipeline. The proposed Trans Mountain Expansion Project ("TMEP" or "the Project") will increase capacity of the existing pipeline from 47,700 cubic meters per day (m^3/d) [300 thousand barrels per day (kb/d)] to 141,500 m^3/d (890 kb/d). As part of the application to the National Energy Board (NEB), Trans Mountain engaged Muse, Stancil & Co. (Muse) to address various supply and market issues related to the Project. Specifically, Muse was asked to conduct the required market analysis and prepare a report to address the following questions:

1) If TMEP is constructed as planned, is it reasonable to expect that the facilities will be highly utilized?
2) If TMEP is built as planned, is it reasonable to expect that it will produce a benefit for Canadian crude oil producers in the form of higher prices for their crude oil production? What is the expected aggregate amount of economic gain to Canadian crude oil producers from the Project?
3) Will TMEP provide access to new markets, and is access to these new markets a benefit to Canadian crude oil producers?

This report addresses these questions through assessing the economic benefits of TMEP to the Western Canadian crude oil producers.

TMEP is an expansion of the existing Trans Mountain Pipeline, which connects Edmonton, Alberta with southwestern British Columbia. There are three crude oil delivery points on the Trans Mountain Pipeline in southwestern British Columbia: the Chevron Burnaby refinery; the Westridge marine terminal (Westridge); and the interconnection at Sumas with the Puget Sound Pipeline. This latter pipeline is connected to four refineries in Washington State. At Westridge, up to Aframax-sized tankers can be loaded with crude oil for delivery to markets in Hawaii, the U.S. West

Coast, Asia-Pacific, and India. Accordingly, the additional capacity provided by TMEP will enable Western Canadian crude oil producers to better access the sizable crude oil markets throughout the Pacific Basin.

The Trans Mountain Pipeline also transports refined product for delivery to third-party product terminals in the Burnaby and Kamloops area. In addition, the Trans Mountain Pipeline receives British Columbia-sourced crude oil at Kamloops. Muse has been advised by Trans Mountain to assume that refined product shipments are approximately 7,950 m^3/d (50 kb/d), and that refined product shipments will not increase as a result of TMEP. Accordingly, Muse has used in its analysis an effective crude oil transportation capacity for TMEP of 133,500 m^3/d (840 kb/d) after expansion, and 37,700 m^3/d (250 kb/d) prior to the Project.

Based on input from Trans Mountain, it is assumed that TMEP will be capable of transporting the effective crude oil transportation capacity of 133,500 m^3/d (840 kb/d) by early in the fourth quarter of 2018. The TMEP benefits over the first twenty years of the project life from 2018 to 2038 are assessed. It should be understood that the twenty-year time period used for the benefits estimate is not a prediction of the ultimate economic or physical lifespan of TMEP. A Canadian-U.S. dollar foreign exchange rate of 1.0/1.0 (i.e., par) has been used for all years of the forecast period.

This report was written by Neil K. Earnest, President of Muse, and other employees of Muse assisted with the preparation of this report. Mr. Earnest holds a Bachelor of Science degree in Chemical Engineering from Michigan State University and an M.B.A. degree from the University of Houston – Clear Lake, and is a Texas-registered Professional Engineer in the discipline of chemical engineering. Mr. Earnest's 30+ years of professional experience has primarily taken place in the crude oil refining and other closely related industries, as his curriculum vitae attached as Appendix B will attest.

Muse is an international energy consulting firm with its headquarters in the Dallas area with additional offices in Houston and London. The company was established in 1984 and is employee-owned. Muse professionals provide a combination of technical and economic services to assist clients in the evaluation of issues and opportunities in the energy sector.

EXECUTIVE SUMMARY

The primary markets for crude oil shipped on the expanded Trans Mountain Pipeline are assessed to be the Burnaby/Puget Sound area (which encompasses the Chevron Burnaby refinery and five refineries in Washington State) and Northeast Asia, with secondary markets in California and Hawaii. The markets of Northeast Asia, California, and Hawaii are not the only potential offshore markets, just the most prospective ones. Sales outside of these regions are highly probable, but likely will be somewhat intermittent.

The proprietary Muse Crude Oil Market Optimization Model has been used to quantifiably evaluate the implications of TMEP to the Canadian crude oil producers. The Crude Oil Market Optimization Model is a mathematical model that predicts the distribution of crude oil throughout North America. Key model input variables include the supply volume of all North American crude oils, North American and overseas refinery crude oil demand, and transportation capacities and costs. Model output includes the resultant crude oil prices and the flows on individual transportation modes. Accordingly, the optimization model is well-suited for assessing the market implications of changes in the logistical infrastructure that enables Canadian crude oil to reach the market. The model has been the analytical foundation of expert reports authored by Muse personnel submitted to the NEB as well as the U.S. Federal Energy Regulatory Commission (FERC).

Two scenarios are evaluated with the Crude Oil Market Optimization Model for each year of the forecast period. These are the:

- **Base Scenario**, which incorporates the transportation modes that are available today, or are expected to be available by 2018, to the Canadian crude oil producers; and,

- **TMEP Scenario**, which adds only TMEP to the transportation modes available in the Base Scenario.

To be clear, the only model input variable that differs between the Base Scenario and the TMEP Scenario is the commissioning of TMEP itself. All other model input variables are exactly the same. Consequently, all differences in the predicted Canadian crude oil prices and transportation flows between the two scenarios can be attributed to TMEP, and only to TMEP.

Since the Crude Oil Market Optimization Model generates an estimate of Western Canadian crude oil prices, a comparison of the two scenarios provides an assessment of the impact of TMEP on Canadian crude oil prices. Table 1 below provides the estimated impact of TMEP on Western Canadian crude oil prices. In general, in the early years of the forecast period the improved market access provided by TMEP is predicted to significantly increase the prices of both Canadian light and heavy crude oils, shifting to mostly increasing the heavy crude oil prices in the latter years.

The higher Western Canadian crude oil prices prior to about 2024 are attributable to two factors. First, TMEP largely eliminates the need for rail transport of Canadian crude oil and, second, TMEP reduces the volume of Canadian crude oil that otherwise would be forced into the finite North American crude oil market. This latter point is discussed in more detail later in this report. Post-2024, rail once again transports an increasing proportion of Western Canadian crude oil to market. In these years, TMEP continues to reduce the volume of Canadian crude oil that otherwise would be forced into the North American market, which acts to improve Western Canadian crude oil prices. The quantum of the pricing benefit is influenced by the degree of market stress in the Canadian crude oil market. In the latter years of the forecast period, the continuously rising volume of Western Canadian heavy crude oil supply imposes greater stress, and the price benefits of TMEP tend to be higher.

TABLE 1

WESTERN CANADIAN CRUDE OIL PRODUCER BENEFITS

EFFECT OF TMEP ON WESTERN CANADIAN CRUDE OIL PRICES

(Real 2015 Canadian Dollars per Barrel)

	2018	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*	*2031*	*2032*	*2033*	*2034*	*2035*	*2036*	*2037*	*2038*
Canadian Mixed Sweet	1.63	1.51	1.16	1.05	1.04	1.07	0.94	0.89	0.71	0.59	0.98	0.84	0.69	0.38	0.51	0.47	0.35	0.29	0.32	0.30	0.29
Canadian Mixed Sour	1.65	1.75	1.26	1.21	1.25	1.47	1.24	1.21	0.90	1.02	1.07	0.87	0.73	0.42	0.61	0.46	0.43	0.40	0.40	0.29	0.45
Sweet Synthetic	2.38	2.43	2.11	1.84	1.65	1.66	1.59	1.93	1.69	1.00	0.98	0.88	0.73	0.16	0.12	0.11	0.14	0.05	0.03	(0.01)	0.03
Lloydminster Blend	1.99	2.31	2.23	1.57	2.07	2.31	1.88	1.78	1.82	1.38	1.59	1.65	1.68	1.07	1.37	1.69	1.80	1.78	1.80	1.87	1.87
Western Canadian Select	2.02	2.35	2.32	1.72	2.21	2.39	1.90	1.81	1.81	1.36	1.56	1.60	1.64	1.02	1.33	1.62	1.74	1.71	1.73	1.80	1.80
Cold Lake Blend	2.20	2.54	2.42	1.74	2.21	2.40	1.97	1.89	1.94	1.59	1.78	1.94	2.01	1.39	1.70	2.10	2.18	2.15	2.17	2.25	2.32
Athabasca DilBit	2.34	2.48	2.57	2.32	2.98	3.25	2.74	2.37	2.34	1.96	2.12	2.07	2.21	1.60	1.88	2.21	2.34	2.31	2.33	2.41	2.49
Athabasca SynBit	5.02	5.18	4.89	4.64	4.50	4.32	2.98	3.34	2.45	2.18	2.33	2.29	2.47	1.87	2.26	2.60	2.70	2.63	2.64	2.68	2.76
Sour Synthetic	2.40	2.15	1.97	2.77	2.74	2.36	2.17	2.11	1.72	1.05	1.11	1.12	1.18	0.94	1.07	0.90	0.03	0.32	0.70	0.66	0.50

Once the price changes are combined with the volume of Western Canadian crude oil supply, the aggregate benefits to Canadian crude oil producers can be determined. For the Canadian crude oil volumes, the Canadian Association of Petroleum Producers (CAPP) 2015 supply forecast is used through 2030 (the end of the CAPP forecast), with an extrapolation by Muse through 2038. Table 2 below provides the estimated benefit to Canadian crude oil producers of TMEP over the 20-year forecast period.[1] The benefits estimate is provided in real CAD$ terms.

The total benefits on an undiscounted basis are CAD$73.5 billion in 2012 dollars, with light crude oil accounting for CAD$10.8 billion (15 percent of the total) and heavy crude oil accounting for CAD$62.7 billion (85 percent of the total).[2] The benefits will continue after 2038, with the expected ongoing operation of the Project.

[1] The 2018 benefits are for the last 61 days in the year, and the 2038 benefits are for the first 304 days in the year.

[2] Muse performed its analysis in real terms in 2015 dollars. The benefits estimate expressed in 2015 dollars have been converted to 2012 dollars by dividing them by 1.0439. The divisor was provided to Muse by the Conference Board of Canada.

TABLE 2

WESTERN CANADIAN CRUDE OIL PRODUCER BENEFITS

IMPACT OF TRANS MOUNTAIN EXPANSION PROJECT

(Millions of 2012 Real Canadian Dollars)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	Total
Canadian Light Sweet	41	228	177	161	160	165	148	140	113	94	158	136	112	62	84	79	59	49	54	50	41	2,311
Canadian Medium Sour	28	176	128	124	129	152	130	126	95	108	115	94	80	46	68	51	48	46	46	33	42	1,866
Sweet Synthetic	128	791	713	630	568	561	531	628	539	319	347	318	272	61	47	43	58	23	14	(5)	12	6,597
Subtotal Light	**197**	**1,194**	**1,019**	**915**	**856**	**879**	**808**	**894**	**747**	**522**	**620**	**549**	**464**	**169**	**199**	**173**	**165**	**118**	**114**	**78**	**95**	**10,774**
Conventional Heavy (LLB)	41	275	256	172	216	233	185	171	172	129	146	150	152	95	120	146	153	149	151	155	128	3,394
Western Canadian Select	44	308	305	226	290	314	250	237	237	179	205	209	215	134	174	212	228	224	228	235	196	4,652
Cold Lake Blend	75	527	513	369	468	509	418	400	411	336	377	410	425	295	361	444	461	454	461	476	410	8,598
Athabasca DilBit	190	1,293	1,419	1,341	1,788	2,060	1,774	1,548	1,581	1,378	1,531	1,433	1,493	1,126	1,382	1,687	1,844	1,882	1,892	1,928	1,629	32,201
Athabasca SynBit	68	445	366	367	395	425	400	601	478	439	470	575	734	560	685	798	849	848	914	997	923	12,337
Sour Synthetic	18	99	93	133	133	115	110	110	91	56	64	69	79	64	74	64	2	24	54	53	34	1,540
Subtotal Heavy	**436**	**2,947**	**2,953**	**2,607**	**3,290**	**3,657**	**3,137**	**3,067**	**2,969**	**2,516**	**2,793**	**2,846**	**3,097**	**2,275**	**2,797**	**3,352**	**3,537**	**3,582**	**3,700**	**3,844**	**3,321**	**62,723**
Total Impact	**633**	**4,141**	**3,972**	**3,522**	**4,147**	**4,535**	**3,945**	**3,962**	**3,715**	**3,038**	**3,413**	**3,395**	**3,561**	**2,443**	**2,996**	**3,525**	**3,702**	**3,700**	**3,814**	**3,923**	**3,416**	**73,497**

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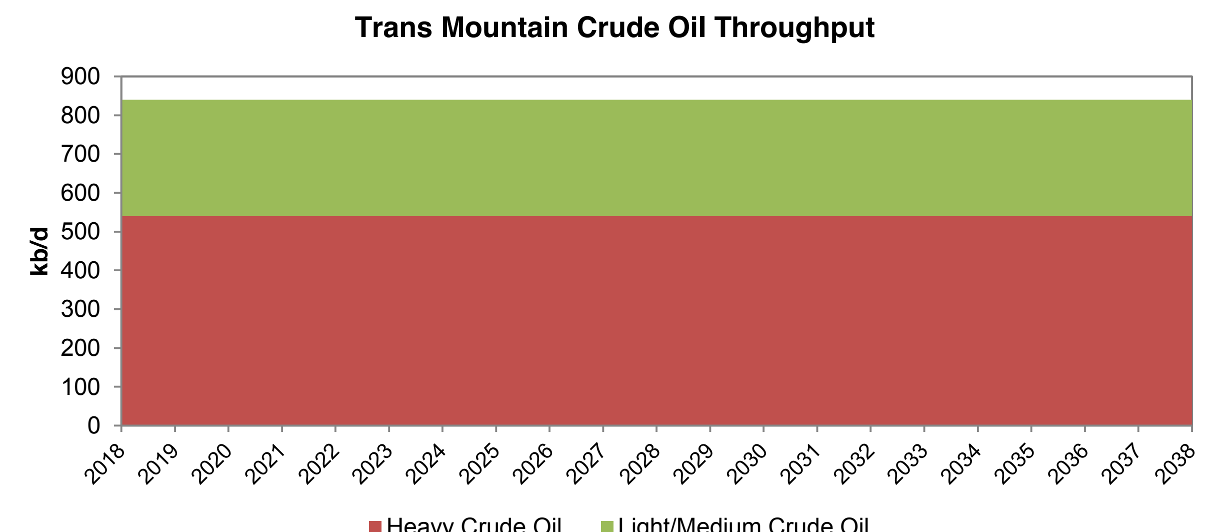
TMEP will add 93,800 m^3/d (590 kb/d) of outbound pipeline transportation capacity from Edmonton. As such, it will be a major addition to the crude oil distribution infrastructure in North America, particularly because it provides access to the sizable Asia-Pacific market and gives Canadian crude oil producers a significant alternative to their historical markets within North America. Accordingly, it can be expected to have a significant effect on the distribution patterns and pricing dynamics for Western Canadian crude oil. Figure 1 below provides the estimated throughput of the Trans Mountain Pipeline once the TMEP is commissioned. As can be observed, the TMEP is forecast to operate at its effective crude oil capacity of 133,500 m^3/d (840 kb/d) for the entire forecast period.

Figure 1

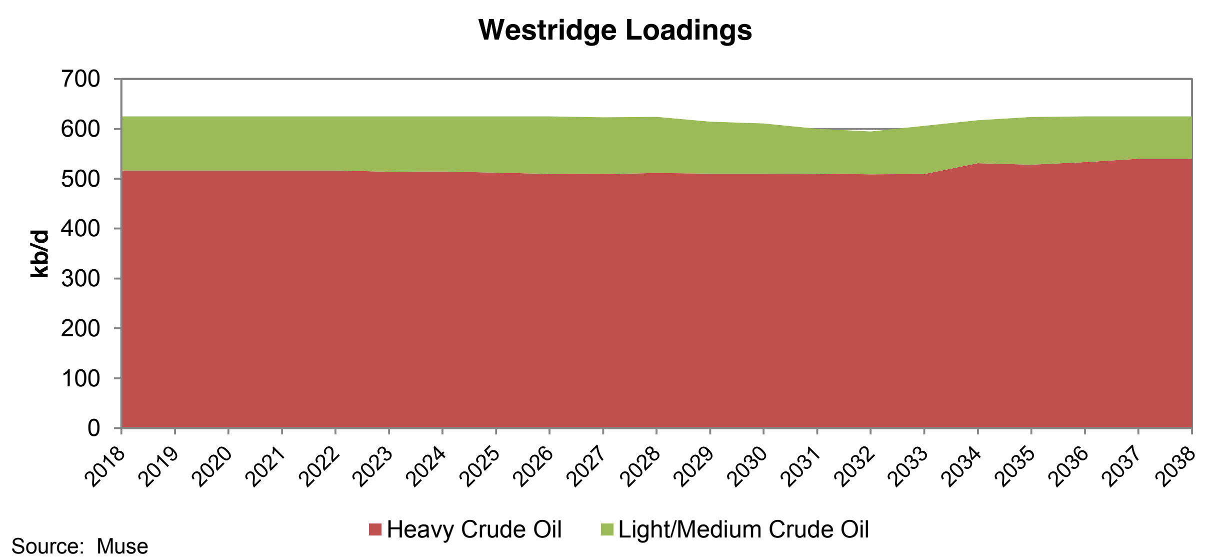


Source: Muse

The Trans Mountain Pipeline is not acting as the price setting mechanism for the price of crude oil at Edmonton, either under the Base Scenario or the TMEP Scenario. The existing Trans Mountain Pipeline has been under apportionment for a number of years, and currently is not the marginal transportation mode. Trans Mountain also is not accessing the incremental market that establishes the crude oil price at Edmonton. Accordingly, just as is the case today, under either the Base or the TMEP Scenario, Trans Mountain Pipeline will not be acting as the price setting mechanism for Western Canadian crude oil prices, because it is not transporting the marginal or incremental barrel of Western Canadian crude oil supplied to the market. For most of the forecast period under the TMEP Scenario, the incremental crude oil barrel will be transported from Western Canada by rail, rather than pipeline.[3]

But, nonetheless, TMEP will affect the crude oil price at Edmonton. The positive price impact of TMEP arises for two reasons: 1) less Canadian crude oil is being forced into the finite North American market because TMEP enables the Canadian crude oil producers to access the higher priced Pacific Basin markets; and 2) lower cost transportation modes are being used during the early years of the forecast period. Regarding the former reason, Figure 2 below shows the forecast Westridge dock loadings for the TMEP Scenario. Of the total dock volume of about 95,400 m^3/d (600 kb/d), roughly 15,900 m^3/d (100 kb/d) of conventional light and medium crude oil in most years is being delivered to California, and does not leave North America. Consequently, about 79,500 m^3/d (500 kb/d) of crude oil is going overseas (including Hawaii), which reduces the volume of Canadian crude oil that must be consumed in the North American market by the same amount. It is a fundamental economic principle that reducing the supply of a commodity, all else equal, will increase its price.

Figure 2



Source: Muse

[3] For the first few years of the forecast period under the TMEP Scenario, other pipelines, rather than rail, are acting as the price setting transportation mode.

The impact of lowering Canadian crude oil supply in North America by 79,500 m^3/d (500 kb/d) can be tested with the Crude Oil Market Optimization Model. Table 3 below provides the results of such an analysis for the year 2025. The column labeled "Lower Supply Scenario" is the Base Scenario for 2025 with the aggregate supply volume of Western Canadian crude oil reduced by 79,500 m^3/d (500 kb/d).[4] As Table 3 demonstrates, the increase in Canadian crude oil prices is about the same as if the supply volume to the North American market is reduced by 79,500 m^3/d (the Lower Supply Scenario), or if this same amount of crude oil is redirected from North America to overseas markets via TMEP.

Table 3

FORECAST 2025 WESTERN CANADIAN CRUDE OIL PRICES

(U.S. Dollars per Barrel)

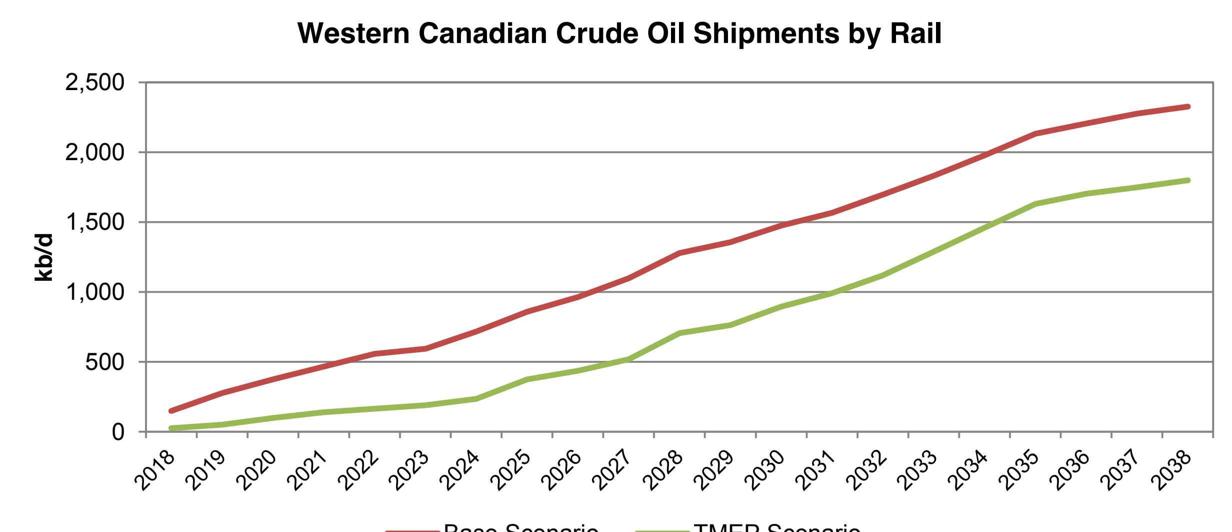
				Differentials	
	Base Scenario	***Lower Supply Scenario***	***TMEP Scenario***	***Lower Supply less Base***	***TMEP less Base***
Canadian Light Sweet	78.69	79.58	79.58	0.89	0.89
Canadian Medium Sour	74.92	76.14	76.13	1.21	1.21
Sweet Synthetic	79.35	80.85	81.28	1.50	1.93
Conventional Heavy (LLB)	63.92	66.02	65.69	2.10	1.78
Western Canadian Select	64.03	66.07	65.84	2.03	1.81
Cold Lake Blend	61.80	64.03	63.69	2.23	1.89
Athabasca DilBit	57.76	59.98	60.13	2.23	2.37
Athabasca SynBit	64.18	66.43	67.52	2.26	3.34
Sour Synthetic	73.67	75.36	75.78	1.69	2.11

Figure 3 below illustrates the effect that TMEP has on the required volume of Western Canadian crude oil rail shipments. In all years, TMEP reduces the volume of rail traffic in Canada (as well as in the U.S.), and in the first few years largely eliminates the need to use rail in Western Canada. It is not a coincidence that TMEP generates the largest

[4] In 2025, 79,500 m^3/d (500 kb/d) of crude oil supply represents about 9 percent of the total Western Canadian crude oil supply volume. Therefore, the supply volume of each grade of Western Canadian crude oil (conventional light sweet, sweet synthetic, Cold Lake Blend, etc.) was reduced by 9 percent in the Lower Supply Scenario.

per barrel benefits shortly after start up (see Table 1), as it is simultaneously reducing the volume of crude oil forced into the North American crude oil market and mostly eliminating the need to utilize more expensive rail transport.

Figure 3

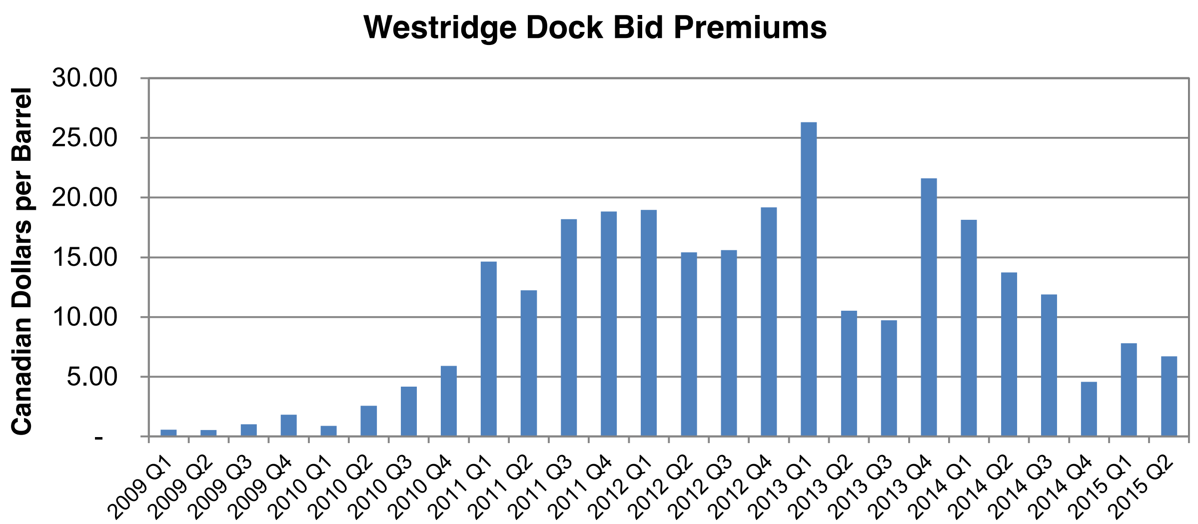


Source: Muse

Rail is almost always a higher cost transportation mode than pipeline. Moreover, the oil industry has been aware that crude oil can be transported by rail for roughly a century and has consistently elected, where possible, to use pipelines rather than rail to transport crude oil between the point of supply to the desired markets. The recent increase in rail transport is attributable to the lack of pipeline capacity, rather than the oil industry discovering some merit of rail of which it heretofore had been unaware, or due to some other improvement in the economics of rail transport.

Regarding the expected utilization of TMEP, as Figure 1 above demonstrates, the Trans Mountain Pipeline post-expansion is projected to operate at capacity throughout the forecast period. This is not a surprising analytical result. The existing Trans Mountain Pipeline has been under constant apportionment since late 2010, and was in intermittent apportionment in prior years. Figure 4 plots the average quarterly Westridge dock bid premiums that shippers have paid in recent years, and these premiums unequivocally demonstrate that there has been high demand for access to the markets that can be reached via Westridge.[5] Furthermore, the voyage distance from Westridge to Northeast Asia is between 65 to 85 percent of that from the region's supply sources in the Middle East, and less than half the distance from West Africa. Accordingly, the relative proximity of Westridge to the Northeast Asia market provides an important long-term structural competitive advantage for the Western Canadian crude oil producers, and helps ensure that the Trans Mountain Pipeline will be fully utilized.

Figure 4



Source: Trans Mountain

More generally, if crude oil is not transported via TMEP to the markets in the Pacific Basin, then the crude oil will be transported, mostly by rail, to North American markets that are linked to the crude oil price in the Atlantic Basin. Such North American markets include the Gulf Coast and the east coast of both Canada and the U.S. In addition, the North American inland markets (Midwest, Midcontinent) are also fundamentally linked to Atlantic Basin pricing via the interconnecting crude oil pipelines to and from the Gulf Coast.

[5] It is also possible that some of the Westridge dock bid premiums were for re-directions to land-based destinations.

Crude oil prices in the Atlantic and Pacific Basins differ. The Atlantic Basin is net long crude oil and the Pacific Basin is net short crude oil. In its 2015 Medium-Term Oil Market Report, the International Energy Agency (IEA) estimates that 572,400 m^3/d (3,600 kb/d) of Atlantic Basin crude oil was imported by Asia in 2014, climbing to 763,100 m^3/d (4,800 kb/d) by 2020.[6] The pricing implication of these trade flows is that Pacific Basin crude oil prices must be structurally higher than crude oil prices in the Atlantic Basin (for crude oil grades of similar quality), as the Pacific Basin prices must be at least high enough to justify the freight costs to move crude oil from the Atlantic to the Pacific.

The global crude oil balances have straightforward implications for the likely utilization of TMEP – structurally higher crude oil prices in the Pacific Basin versus the Atlantic can be expected to generate high shipper interest in accessing the Pacific Basin markets via the Trans Mountain Pipeline. The shippers' alternative is selling their crude oil, generally by rail, into North American markets where the crude oil prices are fundamentally linked to the lower Atlantic Basin prices.

Moreover, Canadian crude oil producers have intermittently struggled with severe market disequilibrium, as was observable in the Canadian heavy crude oil market for much of 2012 and 2013. In Muse's professional opinion, this disequilibrium is primarily due to the lack of market diversification available to the Canadian crude oil producers. Projects such as TMEP offer the Canadian crude oil producer precisely the diversification that they lacked in 2012-2013. TMEP greatly enhances the Canadian crude oil producer's access to new markets, and such access will be a benefit to them.

In conclusion, TMEP will be highly utilized and it will provide significant benefits to Western Canadian crude oil producers, by providing access to the markets in the Pacific Basin. The CAD$2012 value of these benefits is estimated to be CAD$73.5 billion over the first 20 operating years of TMEP. There are essentially three sources of benefits

[6] IEA 2015 Medium-Term Oil Market Report, pg. 82.

from TMEP. First, it will remedy the current situation in which access to the Pacific Basin markets is almost non-existent, thus providing desirable diversification and optionality benefits to the Canadian crude oil producers. Second, it will lessen the amount of Western Canadian crude oil that otherwise will be forced into the North American crude oil markets, thereby generating a price lift for all producers. Finally, in the initial years of TMEP's operation, the need for more expensive rail transportation is largely eliminated, and the transportation savings flow back to the Canadian crude oil producers in the form of higher prices.

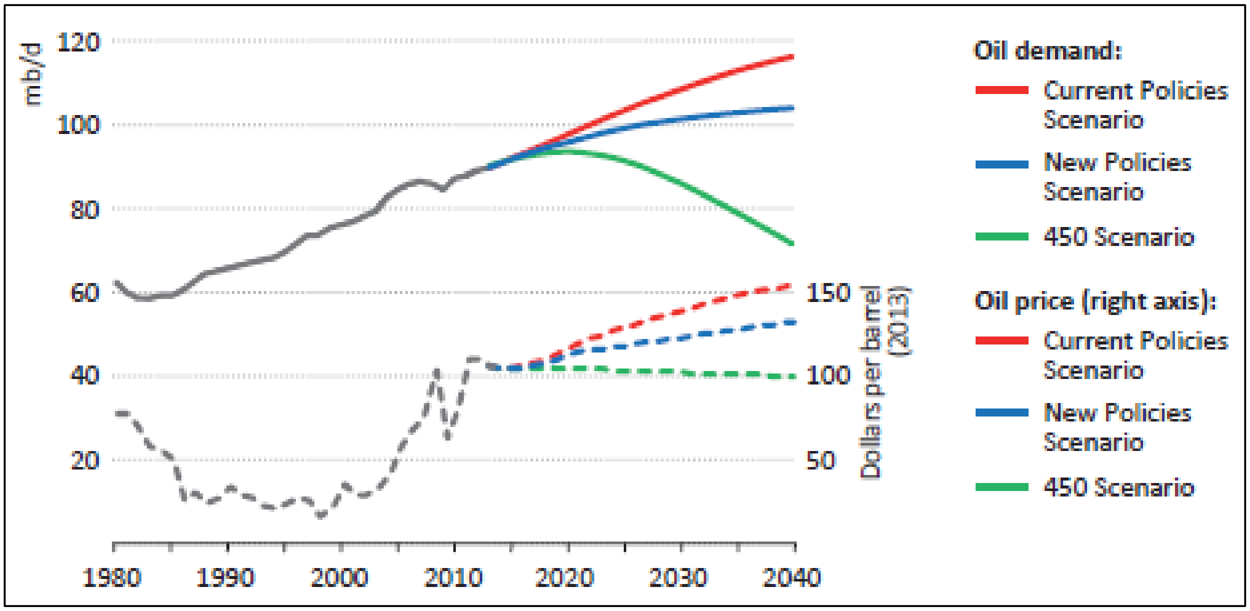
Global Oil Demand Outlook

There are a number of available global oil demand forecasts. In Muse's opinion, the IEA scenarios of potential future paths for energy developments are thoughtfully developed. As of the date of this report, the most recent comprehensive IEA oil demand scenarios are found in its World Energy Outlook 2014, which was released in late 2014. The IEA terms its central scenario the New Policies Scenario. Under this scenario, crude oil demand is projected to increase from 11.9 million m^3/d (74.7 million b/d) in 2013 to 16.0 million m^3/d (100.8 million b/d) by 2040.[7] The IEA also provides two other scenarios in its World Energy Outlook 2014. The Current Policies Scenario predicts rapidly climbing global oil demand, and the 450 Scenario predicts significantly falling global oil demand. This latter scenario adopted a specified outcome, in terms of global greenhouse gas (GHG) emissions, and assumes a set of policies that result in the desired outcome. The global oil demand and oil price forecast for each of the scenarios in the World Energy Outlook 2014 are provided below in Figure 5.[8] Regarding the forward oil price path, the IEA further comments in its more recent Special Report that:

> *The projections in this World Energy Outlook (WEO) Special Report incorporate updated energy price trajectories that reflect recent developments. As a result, fossil-fuel prices in the near term are lower than in the WEO-2014 [World Energy Outlook 2014], but we do not assume these lower prices will be permanent.*[9]

[7] IEA, World Energy Outlook 2014, pg. 117.
[8] Ibid. pg. 97.
[9] IEA, World Energy Outlook Special Report: *Energy and Climate Change*, pg. 20.

Figure 5 **World Oil Demand and Oil Price by Scenario**



The IEA forward path for the average crude oil import prices is also notable in Figure 5 above.[10] Since the oil price simultaneously influences oil demand and oil supply, the IEA uses an iterative modelling exercise to determine the oil price at which the indicated oil demand (by scenario) would be supplied to the market. Even the 450 Scenario, which significantly reduces oil demand, still requires average crude oil import prices in the US$100.00/bbl range (in 2013 dollars).

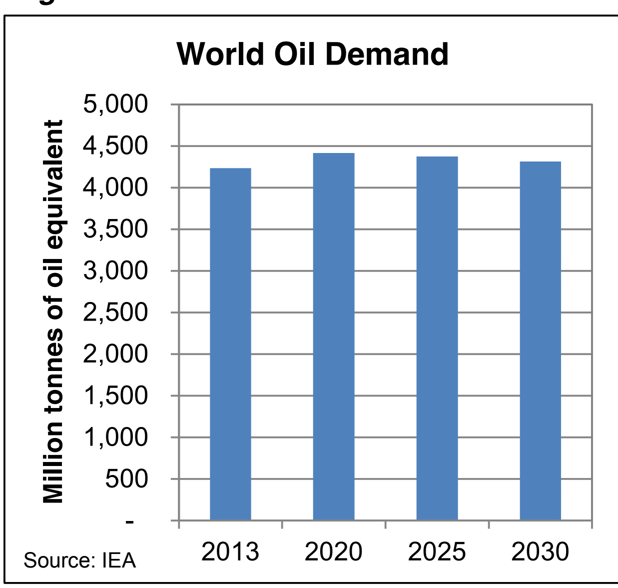
However, even in a world that makes substantive efforts to reduce GHG emissions, Northeast Asia will likely continue to be an attractive market for Western Canadian crude oil producers. In a recent World Energy Outlook Special Report, the IEA outlines what it describes as a "Bridge Scenario" that could deliver a peak in global energy-related emissions by 2020. Like the 450 Scenario from the WEO2014 report, the Bridge Scenario adopted a specified outcome and assumes a set of policies that result in the desired outcome. The IEA further indicates that the Bridge Scenario could be achieved by relying solely upon proven technologies and policies, without changing the economic

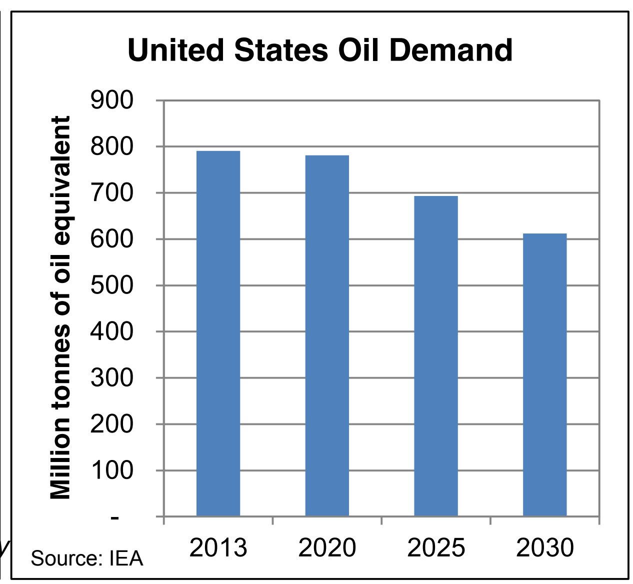
[10] The oil prices shown in Figure 5 are described in the World Energy Outlook 2014 as being average IEA crude oil import prices. See World Energy Outlook 2014, pg. 49.

and development prospects for any region.[11] It should be understood that the IEA does not characterize its Bridge Scenario as the most likely forward path for energy consumption, but as one that global policy makers should consider as they contemplate GHG emission policies.

Figure 6 below provides the IEA's outlook for global and U.S. oil consumption under its Bridge Scenario. Global demand for oil peaks in 2020 the Bridge Scenario, but remains high well into the future. The Bridge Scenario also projects that oil demand in the U.S. will begin a general decline post-2020, and the U.S. is the largest consumer of Canadian crude oil. However, U.S. oil demand is not the same as the consumption of crude oil in U.S. refineries. Today, the U.S. exports millions of barrels per day of refined products to other parts of the world and, thus, crude oil throughput in U.S. refineries considerably exceeds the U.S. requirement for crude oil for its own purposes. The U.S. refineries are extremely competitive from a global perspective due to their high-conversion configurations, large size, ready access to specialized equipment and services, and use of low cost natural gas. It is Muse's opinion that the U.S. refineries will continue to export sizable volumes of refined product for the foreseeable future. Consequently, U.S. demand for crude oil will also exceed the quantity necessary to satisfy the U.S. market for the foreseeable future.

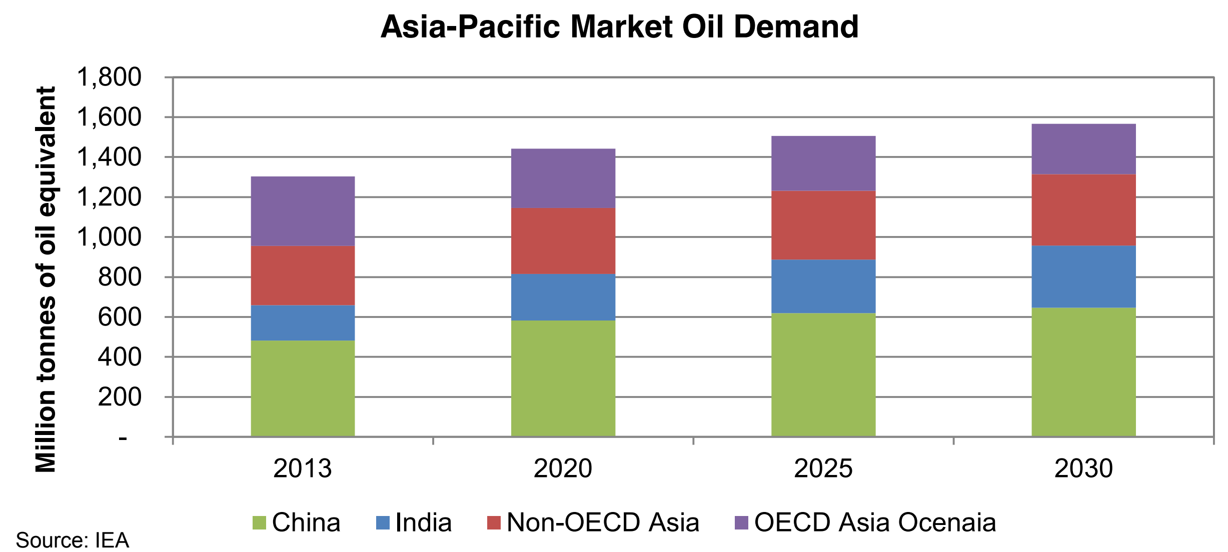
Figure 6





In contrast to the outlook for oil consumption under the Bridge Scenario on a world and U.S. basis, the IEA Bridge Scenario is predicting that oil consumption will continue to climb in the Asia-Pacific markets, as shown in Figure 7 below. It is particularly notable that oil consumption will increase in China, which the analysis has identified as a key market for shippers on TMEP. Per the IEA Bridge Scenario, the rate of oil demand growth in China through 2030 is 1.7 percent per annum, and in the overall Asia-Pacific markets it is 1.1 percent per annum. Should the Bridge Scenario transpire, TMEP will provide the Western Canadian crude oil producers with highly attractive market optionality and diversification benefits, as it enables them to access a region with growing oil demand.

Figure 7

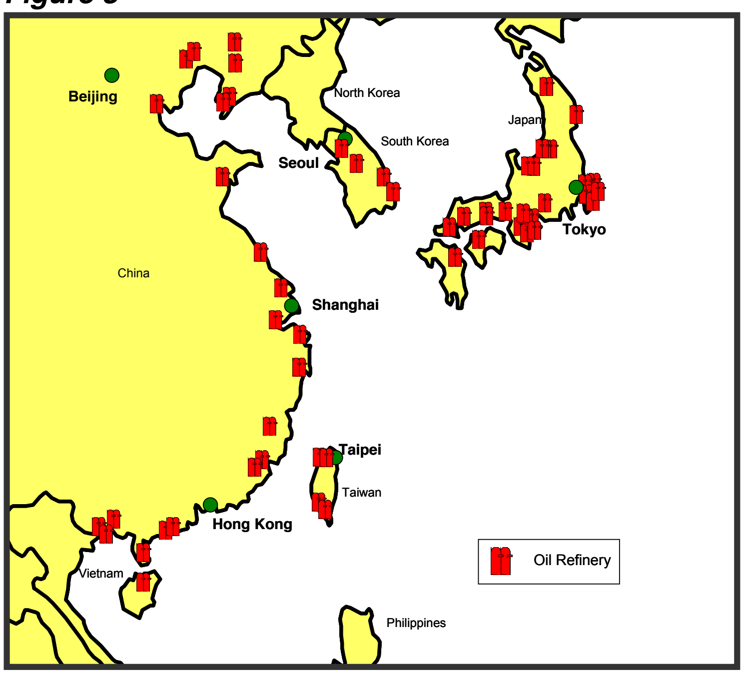


Source: IEA

NORTHEAST ASIA OVERVIEW

Figure 8 illustrates the Northeast Asian refineries explicitly considered in this report. Of all the markets potentially accessible from Westridge, the Northeast Asia market is regarded as the most prospective one for Canadian crude oil producers due to its size, the installed capability of the regional refineries, and its physical proximity to the west coast of Canada.[12] In fact, China and Japan are the second and third largest oil markets in the world, following only the United States. Moreover, refiners in this region are very interested in diversifying their supply sources so as to reduce their heavy reliance upon Middle East crude supply. This is not to say that there will be no other purchasers of Canadian crude oil in Asia-Pacific or India, as such sales are highly likely. However, such sales beyond Northeast Asia are likely to be somewhat opportunistic in nature, mostly due to the greater distances involved and, thus, difficult to analytically quantify.

Figure 8



[12] Western Europe and India are also represented in the Muse Crude Oil Market Distribution Model. However, the model did not elect to route any Canadian crude oil to India from Westridge, and Western Europe is not a permissible destination from Westridge. Accordingly, these two markets are not further discussed in this report.

Table 4 provides the voyage distances to three key Northeast Asia markets from the Middle East, West Africa, and Westridge. The distance from Westridge to Northeast Asia is between 65 to 85 percent of that from the region's supply sources in the Middle East, and less than half the distance from West Africa. Accordingly, the relative proximity of Westridge to the Northeast Asia market provides an important long-term structural competitive advantage for the Western Canadian crude oil producers seeking to supply this market, and helps ensure that the Trans Mountain Pipeline will be fully utilized.

Table 4

WATERBORNE VOYAGE DISTANCES

(Nautical Miles, Round Trip)

		Load Port	
Destination	***Westridge***	***Arabian Gulf***	***Nigeria***
China (Shanghai)	10,253	11,994	20,649
Japan (Yokohama)	8,604	13,277	21,931
South Korea (Ulsan)	9,249	12,546	21,201

In 2014, crude oil imports into China, Japan, South Korea, and Taiwan totaled 2,072,900 m^3/d (13,038 kb/d).[13] At the regional level, the preponderance of crude oil imports is sourced from the Middle East, with an increasing proportion in recent years being obtained from West Africa.

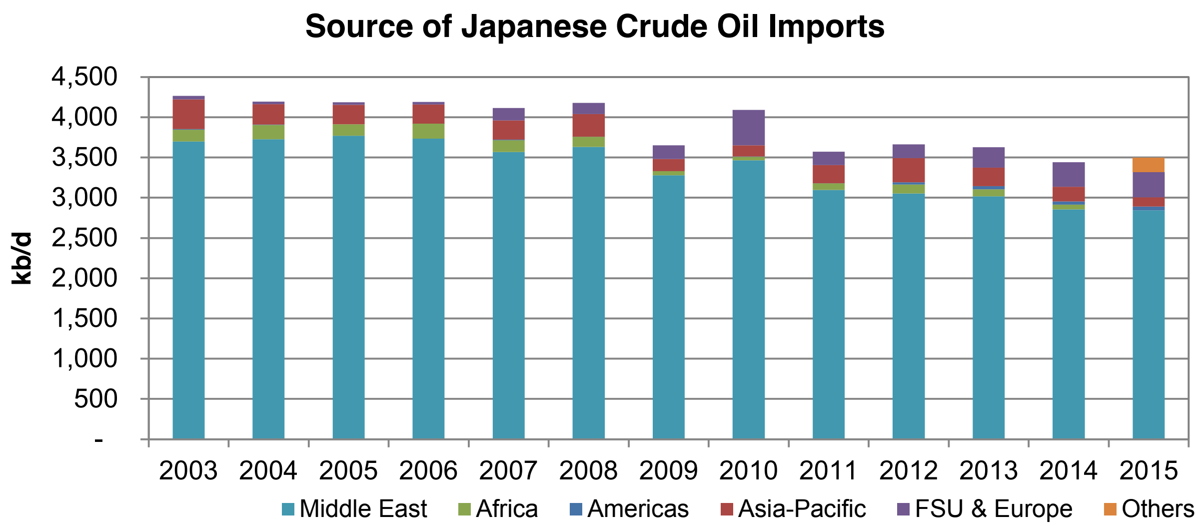
JAPAN

Japan is the second largest importer of crude oil in Northeast Asia, following China. Japan is also advantageously located to receive crude oil shipments from Westridge, as it is the closest major Asian market to the coast of Canada. Total crude oil imports in

[13] The volume of North Korean crude imports is negligible.

2014 totaled 547,100 m^3/d (3,441 kb/d), and Figure 9 provides an overview of the source of Japanese crude oil imports since 2003.

Figure 9

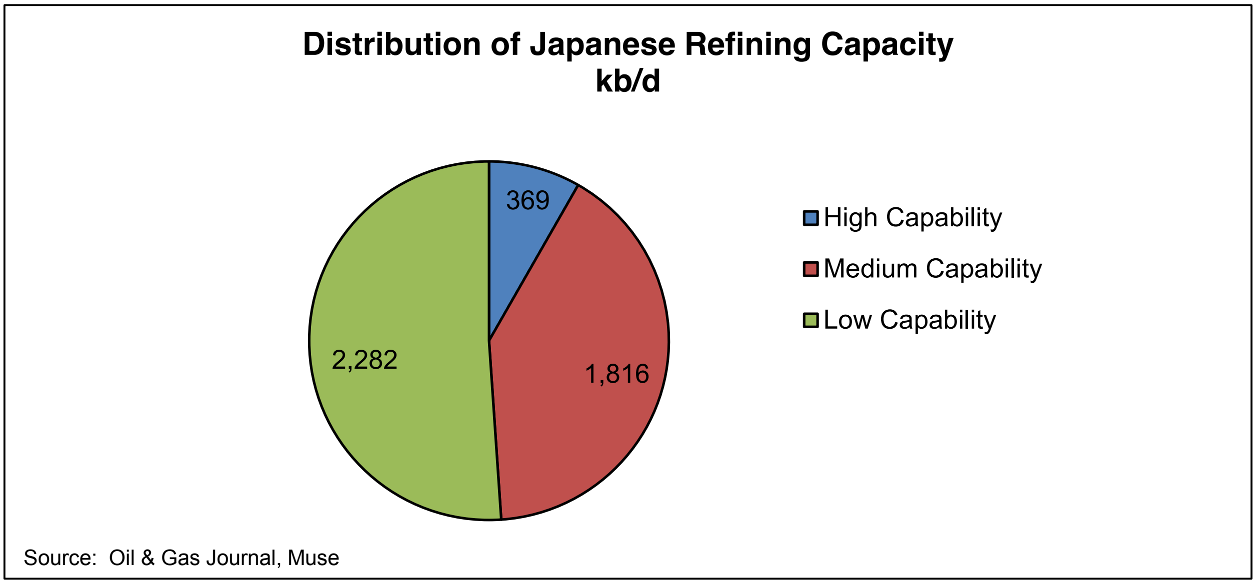


Source: Petroleum Intelligence Weekly

About 83 percent of Japanese crude oil imports were from the Middle East in 2014, and Middle Eastern imports have been the primary supply source for Japanese refiners for many years. Japanese refiners are concerned about this degree of reliance upon the Middle East, and have been seeking to diversify their crude oil sources in recent years. Most Middle Eastern crude oils are in the medium sour category and, accordingly, the average sulphur and gravity of the Japanese imported crude oil basket is reflective of a medium sour grade. Crude oil imports from non-Middle Eastern sources tend to be various sweet grades with about the same crude oil gravity of the Middle Eastern imports. The small volume of imports from the Americas (mostly Latin America) is the exception, as these tend to be both heavy and high sulphur.

Figure 10 provides an assessment of the technical capabilities of the Japanese refining sector to process heavy, high sulphur crude oils. About 8 percent of the Japanese refining industry is assessed to have a high capability to process heavy, high sulphur crude oils, and roughly 40 percent is estimated to have a medium capability. The capability estimates are primarily based upon the proportion of residuum processing capacity, expressed as percent of crude oil distillation capacity, for each Japanese refinery relative to that required to process heavy crude oils. Although the number of Japanese refineries that are capable of processing a high volume of heavy crude oil is not particularly high, the total refining capacity that is in the high and medium category is material, totaling some 347,400 m^3/d (2,185 kb/d).

Figure 10

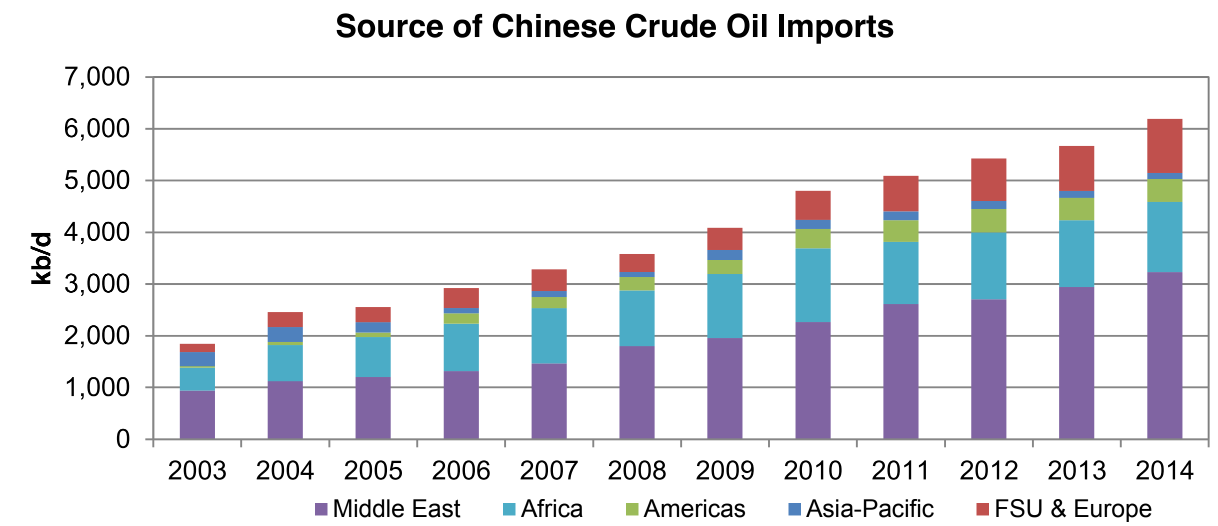


The Japanese industry is a strong potential customer for Canadian synthetic crude oils, particularly the premium synthetic crude oil grades that feature better distillate properties. The interest in the premium grades is because the diesel specifications in Japan are somewhat more difficult to satisfy than in North America. Overall, the potential market size for Canadian crude oil producers in Japan is estimated to be about 93,800 m^3/d (590 kb/d). This market size estimate is based upon an assessment of the capacity and capabilities of the individual Japanese refineries, which is translated into the potential demand estimate for Canadian light and heavy crude oils. It is not a forecast of Canadian crude oil demand in any particular year. A similar methodology is used for the other Northeast Asian markets.

CHINA

China has perhaps the most diversified array of crude oil sources in all of Northeast Asia, as illustrated by Figure 11 below. China is the only country in Northeast Asia for which the share of Middle Eastern crude oil imports is as low as about 50 percent. The trend in Chinese imports is also noteworthy, growing at an annualized rate of 10 percent since 2008. Total crude oil imports in 2014 totaled 982,900 m^3/d (6,182 kb/d).

Figure 11

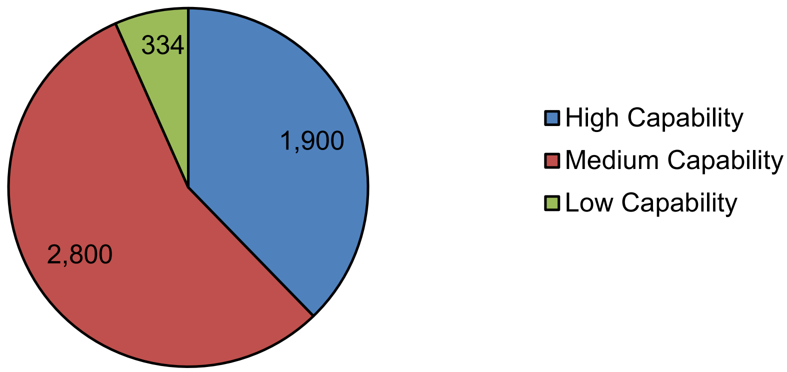


Source: Petroleum Intelligence Weekly

Data regarding the specific crude oil grades imported by China are not available, but the review of the source countries of importation suggests that the Chinese import basket is predominately a blend of medium sour crude oils and various sweet crude oil grades. Figure 12 below provides an assessment of the technical capabilities of the northern coastal Chinese refineries to process heavy, high sulphur crude oils. The analysis is limited to the refineries on the coast itself and those connected to the coast via pipeline to focus on the most prospective customers for Canadian crude oil. The analysis further disaggregates total coastal refining capacity between that in northern China and southern China, as Canadian supply to the southern China refineries is somewhat handicapped by the greater distance from Westridge and the lessened distance from competing sources of crude oil supply.

Figure 12

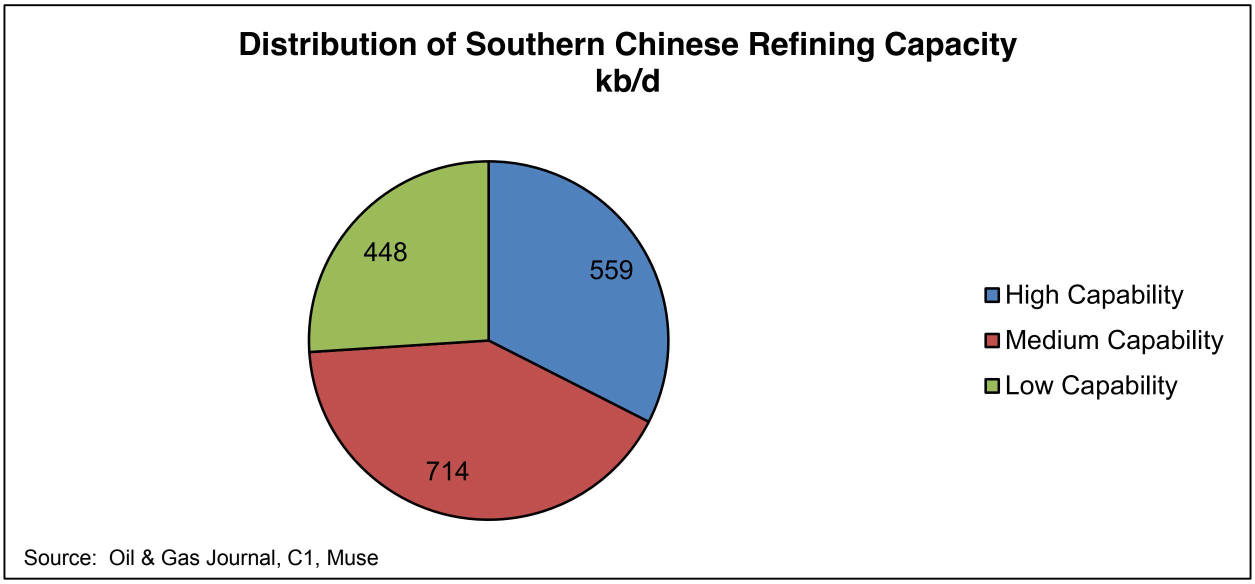
Distribution of Northern Chinese Refining Capacity
kb/d



Source: Oil & Gas Journal, C1, Muse

As can be seen on Figure 12 above, over 90 percent of the northern Chinese refining industry is assessed to have a high or medium capability to process heavy, high sulphur crude oils. The total capacity of the northern Chinese refineries is approximately 799,700 m^3/d (5,030 kb/d). Moreover, the Chinese refiners have been steadily increasing both the capacity and capability of their domestic refineries over the last several years. They specifically have been adding residuum conversion units that will increase their capability to process heavy crude oil, and this trend is expected to continue. The attributes of the southern Chinese refineries are shown below in Figure 13.

Figure 13



The current potential market size for Canadian crude oil producers in China is estimated to be approximately 168,500 m^3/d (1,060 kb/d), and the market potential is estimated to be growing at a rate of about 5 percent per year.

SOUTH KOREA

South Korea imported 404,000 m^3/d (2,541 kb/d) of crude oil in 2014. Figure 14 below provides an overview of the source of the South Korean crude oil imports over the last 13 years. As shown, roughly 85 percent of South Korean imports are from the Middle East. Crude oil imports from Asia-Pacific tend to be various heavy sweet grades.

Figure 14

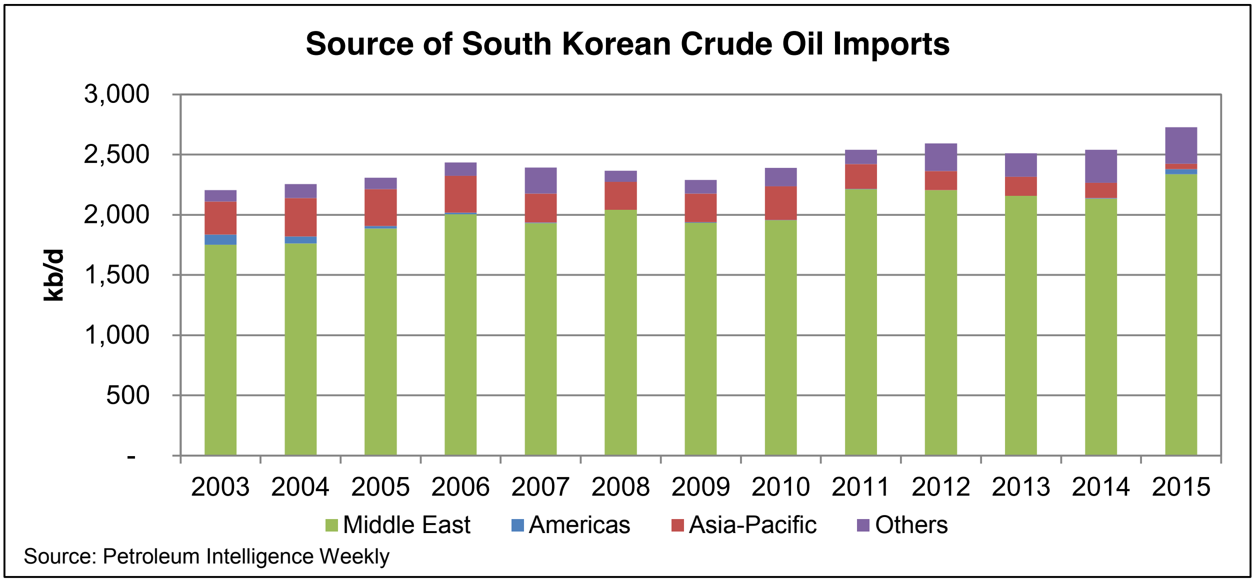
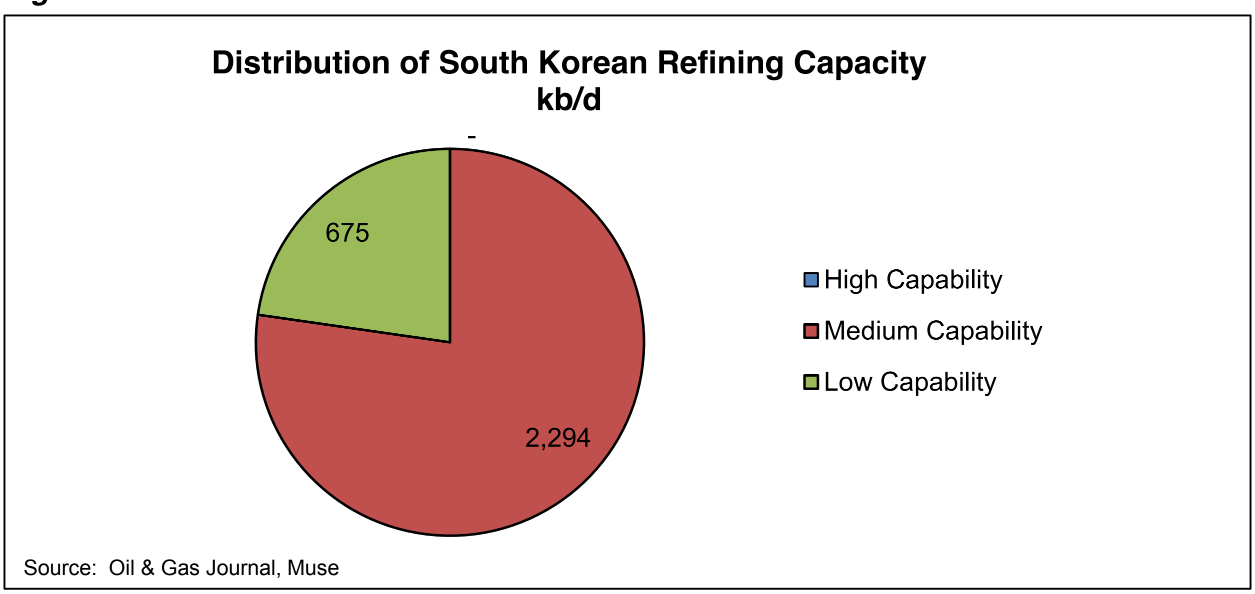


Figure 15 below provides an assessment of the technical capabilities of the South Korean refining sector to process heavy, high sulphur crude oils. Although many of the South Korean refineries are very large, they are not specifically designed to process heavy sour crude oils. Nonetheless, South Korean refining capacity totals 472,000 m^3/d (2,969 kb/d) and, accordingly, there is a strong potential for Canadian crude oil sales to South Korea. The overall potential market size for Canadian crude oil is estimated to be approximately 77,900 m^3/d (490 kb/d).

Figure 15



TAIWAN

Total Taiwanese crude oil imports were 137,400 m^3/d (864 kb/d) in 2014. An overview of the sources of the Taiwanese crude oil imports over the last 12 years is provided on Figure 16. Fully 83 percent of Taiwanese imports are from the Middle East. A review of the countries of importation suggests that the Taiwanese refineries predominately process a mix of light sweet and medium sour crude oils.

Figure 16

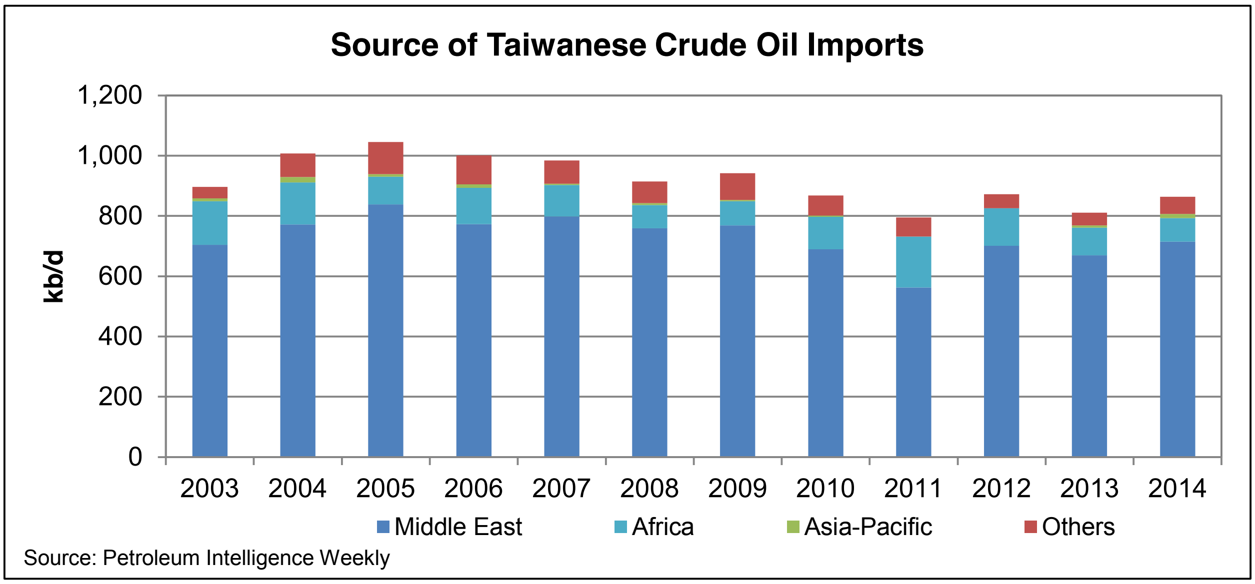
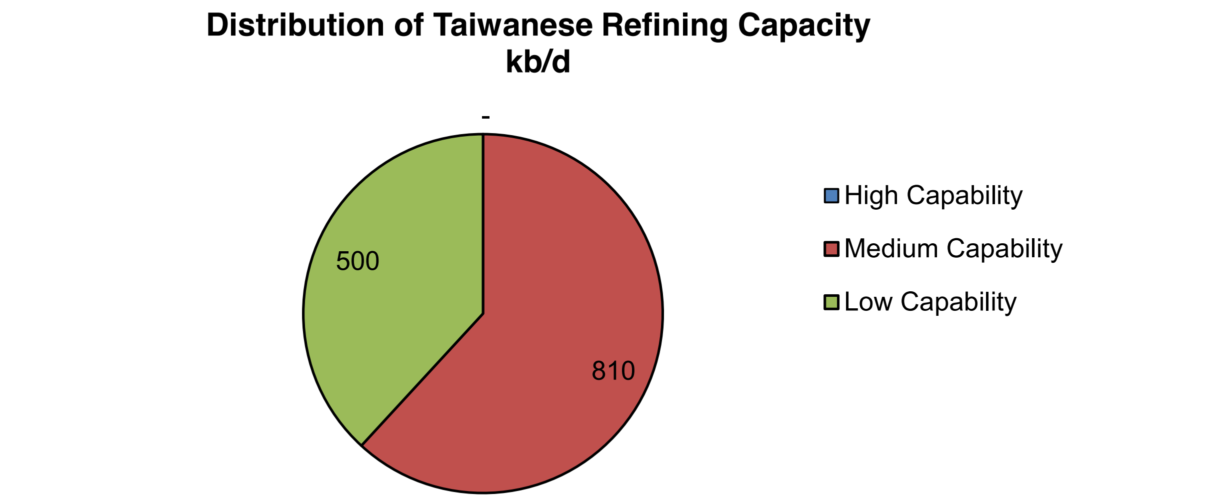


Figure 17 below provides an assessment of the technical capabilities of the refineries in Taiwan. Similar to the situation in South Korea, the Taiwanese refineries are large and quite complex, but not specifically designed to process heavy sour crude oils. Taiwanese refining capacity totals 208,300 m^3/d (1,310 kb/d). The overall potential market size for Canadian crude oil is estimated to be approximately 30,200 m^3/d (190 kb/d).

Figure 17



Source: Oil & Gas Journal, Muse

Table 5 provides a summary of the potential demand in Northeast Asia for Western Canadian crude oils. Total potential demand exceeds 369,700 m^3/d (2,330 kb/d) and, moreover, Northeast Asia has one of strongest projected oil demand growth rates in the world. Due to its size and proximity, Northeast Asia is expected to be a very important market for the shippers on TMEP.

Table 5

TOTAL NORTHEAST ASIA POTENTIAL DEMAND

Country	*m^3/d*	*kb/d*
Japan	93,500	590
Northern China	129,800	820
Southern China	38,400	240
South Korea	78,300	490
Taiwan	29,700	190
Total	**369,700**	**2,330**

TMEP BENEFIT ANALYSIS

The proprietary Muse Crude Oil Market Optimization Model has been used to quantify the effect of TMEP on Western Canadian crude oil prices. This model has been developed by Muse for use in a wide variety of commercial applications, including detailed forecasts of Western Canadian crude oil prices, assessment of likely Western Canadian crude oil consumers, and pipeline utilization studies. The Crude Oil Market Optimization Model is a distribution model that predicts the flow of crude oil to various markets and the Western Canadian crude oil prices that result from such flows. Consequently, it is well-suited for assessing the market implications of changes in the transportation infrastructure that enables Canadian crude oil to reach the market.

The Crude Oil Market Optimization Model is run twice for each year in the period 2018 to 2038. The model is first run without TMEP (the Base Scenario), and the disposition and pricing of all Western Canadian crude oil grades are ascertained. Consequently, all of the market benefits that are attributable to all export routes, including the existing Trans Mountain Pipeline, from Canada are embedded in the analytical results from this first run. For the second model run in a given year, all model input variables (crude oil supply, refinery capacity, etc.) are held constant, but the model is now permitted to use TMEP, if desired, at its indicated capacity and tolls. Accordingly, all differences between the two model runs, including the resultant Canadian crude oil prices, are attributable only to TMEP.

The model uses linear programming (LP) techniques to allocate all Canadian and U.S. crude oil production among Canadian, U.S., and Northeast Asian refineries, within the confines of existing and expected pipeline, rail, barge, and refinery capacity constraints, while maximizing the Western Canadian crude oil netback price at Edmonton.[14] Said differently, the model is seeking to route Western Canadian crude oil to the refineries that will pay the most for the crude oil, taking into consideration the transportation costs from Canada, while simultaneously having due regard for the finite capacities of the pipeline and rail routes, and the refineries themselves.[15] In essence, the model attempts to mirror the crude oil distribution pattern that would arise from an efficiently operating crude oil marketplace. The model is not seeking to maximize or minimize the throughput of Trans Mountain or any other pipeline.

The inputs to the model include: (1) the supply of Canadian and U.S. crude oil, by individual crude grade (heavy sour, sweet synthetic, etc.); (2) the capacity of each pipeline, rail, and barge route (by segment, where necessary); (3) where applicable, pipeline volume commitments; (4) the pipeline tolls/rates and other transportation costs (e.g., tanker, barge, and rail costs); (5) the crude oil capacity of each refinery as well as refinery-specific constraints; and (6) the refining value of the crude oil grades at each refinery, expressed as a function of crude oil throughput. The supply of U.S. crude oil is a model input because it influences the disposition of Canadian crude oil (as U.S. and Canadian crude oil frequently use the same pipeline) and consumes refinery capacity that would be otherwise available for Canadian crude oil. Once the variables are input into the model, LP techniques are used to maximize the desired outcome, which in this case is the aggregate netback crude oil price, while simultaneously satisfying all of the constraints imposed upon the solution.

[14] The netback price is the price that a specific grade of crude oil is sold for at its market-clearing point, less the transportation cost between Edmonton and the market-clearing point. The market-clearing point is also frequently referred to as the parity point. The parity point can, and does, differ between crude grades (heavy sour, sweet synthetic, etc.).

[15] The model is also seeking to minimize the transportation cost (thus maximizing their netback) for various U.S. crude oil grades. It is necessary to also consider U.S. crude oils because U.S. and Canadian crude oils are frequently competing for the same pipeline and refinery capacity.

CRUDE OIL SUPPLY

There are several authoritative public long-term forecasts of Western Canadian crude oil production. The NEB provides Canadian crude oil production outlooks every other year. CAPP releases crude oil supply and production forecasts annually, and the associated report contains a great deal of information regarding the basis for the Canadian crude oil supply outlook and of crude oil market developments. The Alberta Energy Regulator (AER), a quasi-judicial regulatory agency of the Government of Alberta, provides annual crude oil production outlooks for Alberta, which constitutes the preponderance of Western Canadian crude oil production. In Muse's experience, the CAPP crude oil supply forecasts are commonly used for pipeline regulatory purposes in Canada and the U.S.

The June 2015 CAPP supply forecast is the fundamental basis for the Western Canadian crude oil supply outlook used for this analysis.[16] It is the most current of the available forecasts, and is also the only one that specifically provides a crude oil supply outlook for Western Canada. The others provide only a crude oil production outlook. In Western Canada, the volume of crude oil production differs from the volume of crude oil grades supplied to the market because of diluent addition and volumetric losses across upgraders. In addition, CAPP describes its 2015 crude oil supply forecast as being one that is reflective of the current crude oil price environment. In the introduction of the report, CAPP states:

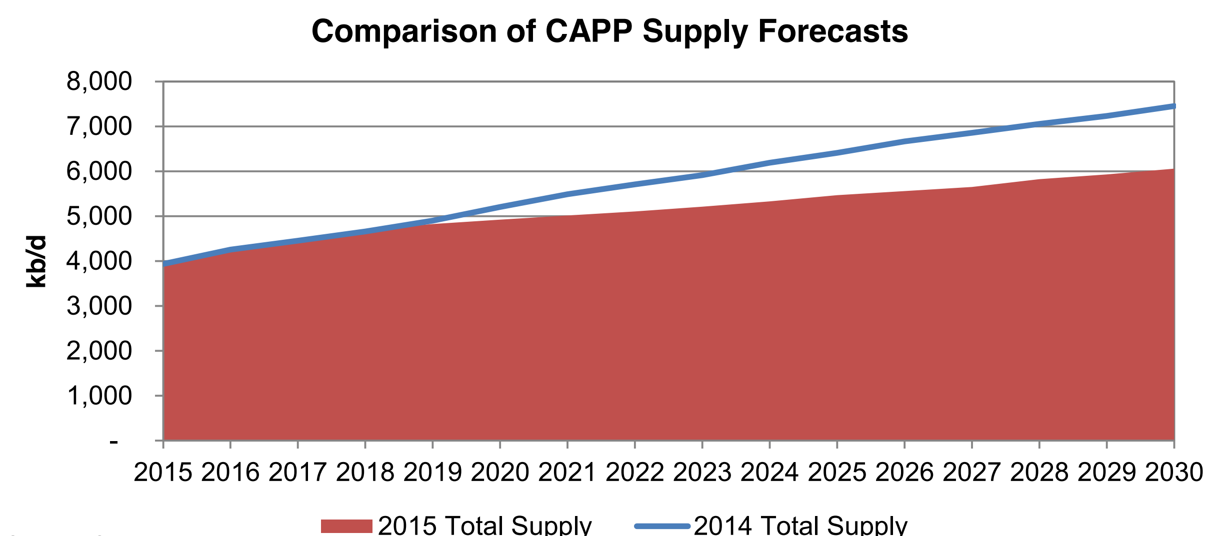
> *The Canadian crude oil industry is managing risks on multiple fronts in an environment transformed by lower oil prices. During the latter part of 2014, the industry witnessed a rapid drop in prices. The benchmark WTI crude oil spot price dropped from a peak of over US$100 per barrel in June 2014 to below US$55 per barrel in December. From January to April 2015, the oil price averaged around $50 per barrel. Lower oil prices are challenging project economics. Against this changed backdrop, CAPP's latest Canadian*

[16] CAPP Crude Oil Forecast, Markets & Transportation, June 2015.

oil production forecast outlook anticipates that total oil production continues to grow but at a slower pace and is 1.1 million b/d lower by 2030 than was the forecast a year ago.[17]

Figure 18 provides a comparison of the 2015 CAPP supply forecast to its 2014 supply forecast. As can be observed, the 2015 crude oil supply forecast, which is reflective of the current lower oil price environment, is appreciably lower than the 2014 forecast for much of the forecast period. However, the 2015 CAPP forecast still projects that crude oil supply will increase from 2015 to 2030 by 52 percent, or by 328,000 m^3/d (2,063 kb/d).

Figure 18



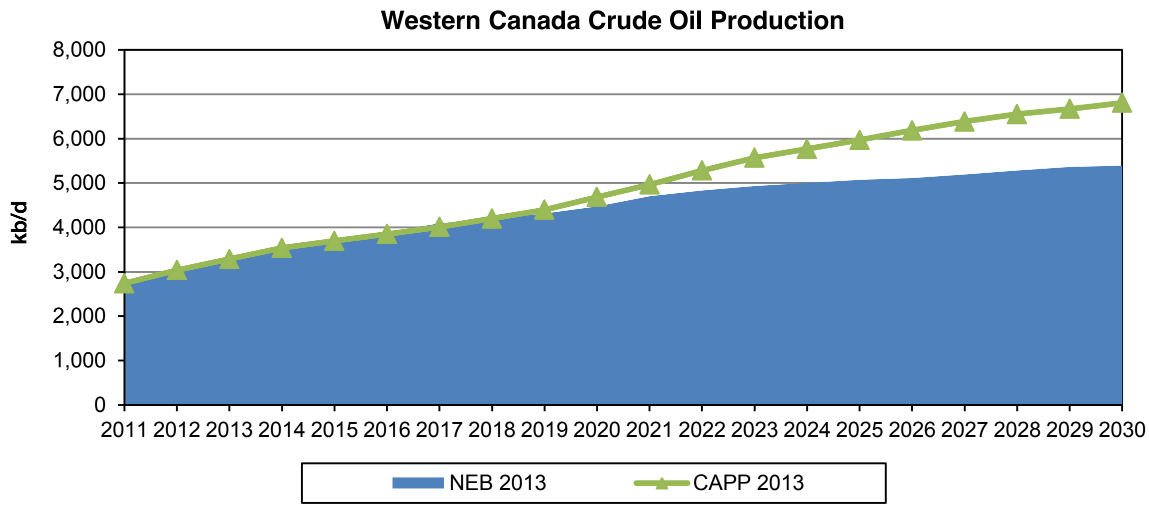
Source: CAPP, Muse

Figure 19 below provides a comparison of the NEB 2013 Reference Case production forecast to the CAPP production forecast of the same year (the 2015 NEB report is not released until November).[18] Until about 2020, the production forecasts are very close. Post-2020, the NEB growth rate of crude oil production is less than that of CAPP, and by the end of the forecast period the NEB crude oil production volume is about

[17] Ibid, pg. 1.
[18] The NEB report is: *Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035*, November 2013. The data for the NEB crude oil production outlook were obtained from Appendix Tables A3.3. The CAPP report is: *Crude Oil: Forecast, Markets & Transportation*, June 2013.

20 percent less than the CAPP production volume. Nonetheless, the most recent NEB forecast is predicting that between 2013 and 2030 the increase in crude oil production will be 333,900 m^3/d (2,100 kb/d).

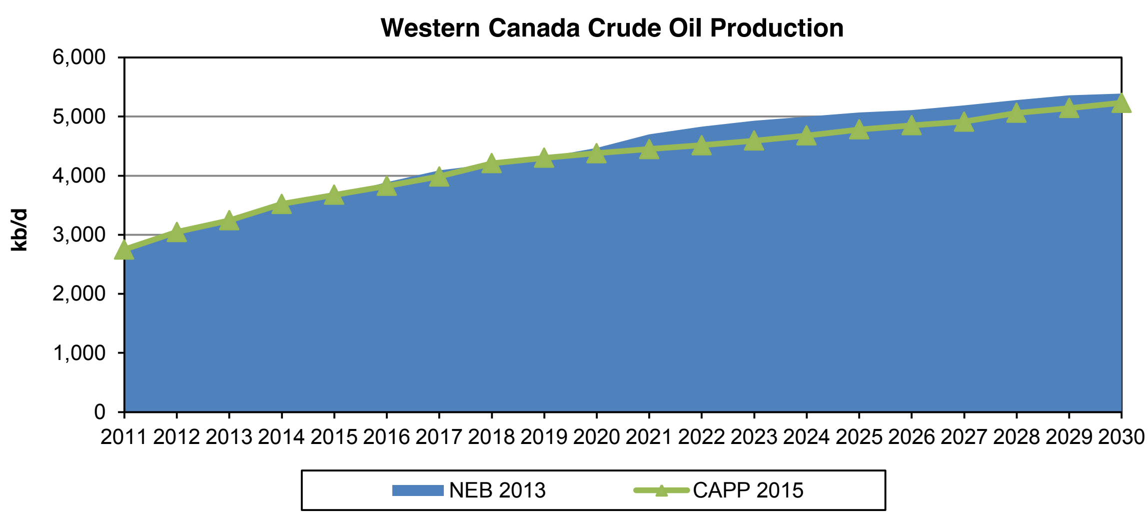
Figure 19



Source: NEB, CAPP

Figure 20 below compares the 2013 NEB Western Canadian crude oil production forecast and the most recent CAPP (2015) production forecast. The production forecasts are very similar throughout the forecast period.

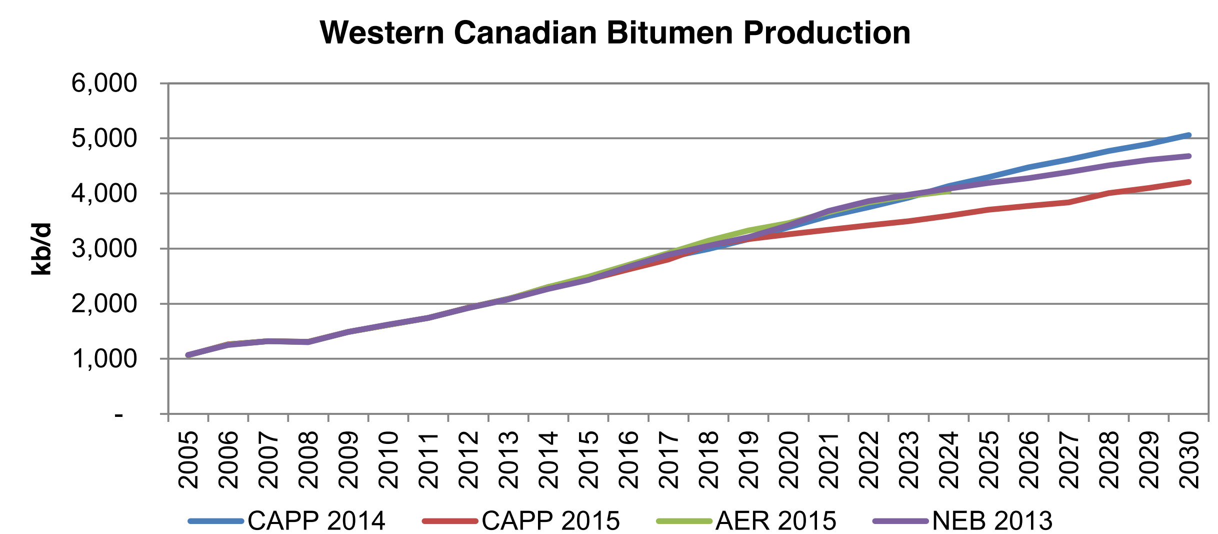
Figure 20



Source: NEB, CAPP

The final comparison is of Western Canadian bitumen production, which comprises the preponderance of the total Western Canadian crude oil production. This comparison of the latest available NEB and AER, plus the two most recent CAPP outlooks, is shown on Figure 21 below.[19] The outlooks are similar, and the CAPP 2015 bitumen production forecast is the lowest of the four. Figure 21 also provides some perspective of the historical growth rate of Western Canadian bitumen production.

Figure 21



Source: NEB, CAPP, AER

In summary, the NEB, CAPP, and AER forecasts differ in the details, but more broadly communicate the same message — the forward outlook for Western Canada is one of significant increases in heavy crude oil supply. As a practical matter, such increases must be transported to the market by some combination of pipeline and rail. The Project represents a small portion of the incremental transportation capacity that will have to be added over the next decade and beyond.

[19] The AER outlook is provided in ST98-2015; Alberta's Energy Reserves 2014 and Supply/Demand Outlook 2015-2024; Figure S3.8; pg. 3-21. The AER forecast ends in 2024.

The 2015 CAPP supply forecast terminates in 2030, and Muse has generated an extension from 2031 to 2038 as outlined below:

- 2031 to 2035: The rate of change (either positive or negative) in the individual crude oil categories provided by CAPP for 2025 to 2030 is applied to the CAPP 2030 estimate. For example, between 2025 and 2030 CAPP is projecting that conventional light and medium crude oil supply would grow at an annualized rate of 0.75 percent. Therefore, from 2031 to 2035 the conventional light and medium crude oil supply grows by 0.75 percent per year.

- 2036 to 2038: The rate of change in the individual crude oil categories provided by CAPP for 2025 to 2030 is halved, and applied to the extrapolated 2035 volume estimate.

The CAPP forecast disaggregates total Canadian supply into Light and Medium Conventional, Conventional Heavy, Upgraded Light (Synthetic), and Oil Sands Heavy. To improve the precision of the optimization model, Muse further disaggregates the Oil Sands Heavy category into Western Canadian Select, Cold Lake Blend, Athabasca Dilbit, Athabasca Synbit, and sour synthetic. The CAPP forecast and the extension are shown in Appendix Table A-1. The supply totals found in Appendix Table A-3 equal that predicted by the CAPP 2015 forecast through 2030.

CRUDE OIL TRANSPORTATION INFRASTRUCTURE AND TOLLS

For the Base Case, all of the major crude oil pipelines in North America are modeled.[20] It is assumed that certain U.S. pipeline projects will be commissioned that, in Muse's opinion, are very likely to proceed, as well as the integrity-related Enbridge Line 3

[20] California and offshore Gulf of Mexico crude pipelines are not included in the model, as they have little influence on the distribution of crude oil in North America.

Replacement Project. As of 2018, the commissioning date for TMEP, the key pipeline assumptions are:

- **Existing Trans Mountain Pipeline.** Total pipeline capacity is 47,700 m^3/d (300 kb/d), less 7,950 m^3/d (50 kb/d) of refined product shipments, for an effective crude oil capacity of 39,750 m^3/d (250 kb/d). The total permissible heavy crude oil capacity is 9,500 m^3/d (60 kb/d), and the Westridge dock loading capacity is 12,600 m^3/d (79 kb/d).

- **Expanded Trans Mountain Pipeline (Post-TMEP).** Total pipeline capacity is 141,500 m^3/d (890 kb/d), less 7,950 m^3/d (50 kb/d) of refined product shipments, for an effective crude oil capacity of 133,500 m^3/d (840 kb/d). The total permissible light and heavy crude oil capacities are 47,700 m^3/d (300 kb/d) and 85,900 m^3/d (540 kb/d), respectively, reflecting the capacities of Line 1 and Line 2. The Westridge dock loading capacity is 99,400 m^3/d (625 kb/d). All Trans Mountain capacity assumptions were provided by Trans Mountain Pipeline.

- **Keystone.** The Keystone Pipeline has an origination capacity of 94,000 m^3/d (591 kb/d) with an estimated volume commitment of 84,300 m^3/d (530 kb/d). The Keystone Pipeline can make deliveries to Wood River, Patoka, and Cushing.

- **Enbridge Mainline.** The Mainline segments have the following capacity:
  - Cromer to Clearbrook – 414,400 m^3/d (2,606 kb/d)[21]
  - Clearbrook to Superior – 446,500 m^3/d (2,808 kb/d)
  - Superior to Chicago – 156,500 m^3/d (984 kb/d)
  - Superior to Flanagan – 190,800 m^3/d (1,200 kb/d)
  - Superior to Sarnia (Line 5) – 86,000 m^3/d (541 kb/d)[22]
  - Chicago to Stockbridge (Line 6B) – 90,600 m^3/d (590 kb/d)
  - Sarnia to Montreal (Line 9B) – Origination capacity of 47,700 m^3/d (300 kb/d), with a maximum heavy crude oil capacity of 7,900 m^3/d (50 kb/d).
  - An effective utilization factor of 90 percent has been applied to the aggregate Mainline capacity, consistent with the Enbridge Line 3 Replacement Project Application to the Minnesota Public Utilities Commission.[23]

- **Enbridge North Dakota System.** The following capacities have been used for the Enbridge North Dakota System:
  - To Clearbrook/Superior – 69,200 m^3/d (435 kb/d)
  - To Cromer – 33,100 m^3/d (145 kb/d)

- **Enbridge Flanagan South and Spearhead.** The Enbridge Flanagan South pipeline project has a capacity of 135,900 m^3/d (855 kb/d) with an estimated volume commitment of 500 kb/d. The Spearhead Pipeline has a capacity of 30,700 m^3/d (193 kb/d). Both of these pipelines originate in the Chicago area and terminate at Cushing.

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[21] The Enbridge Mainline upstream of Cromer is not included in the Crude Market Optimization Model.

[22] In 2018, Line 5 capacity is reduced by approximately 5,600 m^3/d (35 kb/d) to account for shipments of natural gas liquids (NGLs) in the pipeline. NGL shipments are assumed to decrease by about 2 percent per year, and the Line 5 capacity available for crude oil shipments increases accordingly. Line 5 is a light crude oil line only.

[23] Certificate of Need Application for the Minnesota Public Utilities Commission; Enbridge Energy, Limited Partnership Line 3 Replacement Project; MPUC Docket No. PL-9/CN-14-916, April 2015, pg. 3-25.

- **Cushing to the Gulf Coast.** The key pipelines include:
  - Seaway Pipeline (Cushing to Houston) – 163,800 m^3/d (1,030 kb/d), with a 95,400 m3/d (600 kb/d) extension from Houston to the Beaumont/Port Arthur area. There are also volume commitments associated with the Seaway system that are assumed to be 31,800 m^3/d (200 kb/d) in 2018.
  - Keystone Cushing Marketlink (Cushing to Beaumont) – 79,500 m^3/d (500 kb/d), with a spur to Houston of the same capacity.

- **Rockies.** Total crude oil export pipeline capacity to the Rockies (PADD IV) is estimated to be 81,700 m^3/d (514 kb/d) throughout the forecast period. The Crude Oil Market Optimization Model does not individually model the various export pipelines that connect Alberta with the Rockies. The outbound (from the Rockies) pipelines capacities are:
  - Platte Pipeline to Wood River/Patoka – 23,100 m^3/d (145 kb/d)
  - White Cliffs Pipeline to Cushing – 32,800 m^3/d (150 kb/d)
  - Saddlehorn/Grand Mesa to Cushing – 74,000 m^3/d (400 kb/d)

- **Lower Midwest.** Key pipelines in the Lower Midwest include:
  - Southern Access Extension (Flanagan to Patoka) – 47,700 m^3/d (300 kb/d)
  - Energy Transfer Crude Oil Pipeline Project (Patoka to Beaumont) – 79,500 m^3/d (500 kb/d)
  - Ozark (Cushing to Wood River) – 34,200 m^3/d (215 kb/d)

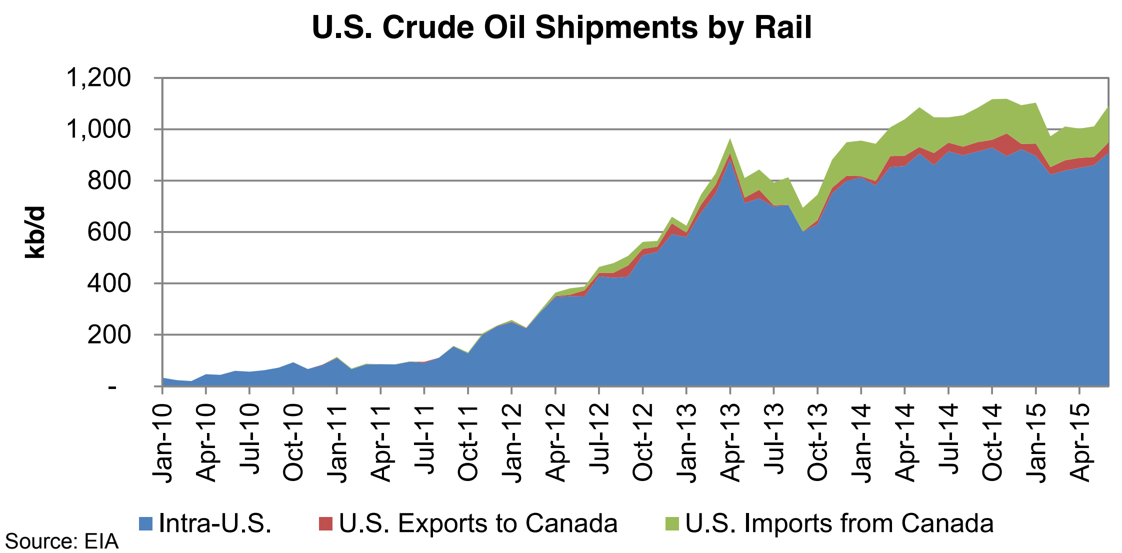
- **West Texas and Gulf Coast.** The key West Texas to Gulf Coast and the intra-Gulf Coast pipelines are:
  - Magellan Longhorn (West Texas to Houston) – 43,700 m^3/d (275 kb/d). Volume commitments are estimated to be 90 percent of pipeline capacity.

- Magellan BridgeTex (West Texas to Houston) – 47,700 m^3/d (300 kb/d). Volume commitments are estimated to be 90 percent of pipeline capacity.
- Sunoco Permian Express (West Texas to Beaumont) – 23,800 m^3/d (150 kb/d). Volume commitments are estimated to be 90 percent of pipeline capacity.
- Plains Cactus (West Texas to Corpus Christi) – 47,200 m^3/d (297 kb/d).
- Shell Zydeco (Houston to Louisiana) – 47,700 m^3/d (300 kb/d) at Houston, and 59,600 m^3/d (375 kb/d) at Beaumont.

- **Barge.** Barge capacity is estimated to be 17,500 m^3/d (110 kb/d). The barge route is via the Mississippi River from the Wood River area to Louisiana.

- **Rail.** Rail has become an important crude oil transportation mode in North America. Figure 22 below illustrates the growth of crude by rail transport from January 2010 through June 2015 (the most recent data as of the date of this report). Crude oil shipments by rail in the U.S. exceed 159,000 m^3/d (1,000 kb/d), and an increasing proportion of the total volume is rail shipments from Canada into the U.S. In addition to the U.S. rail volumes, there are also crude oil shipments by rail within Canada itself.

Figure 22



Source: EIA

At some point, rail deliveries of Canadian heavy crude oil to a port for export overseas becomes necessary to avoid completely saturating the available North American heavy crude oil market, with a consequential collapse in Western Canadian heavy crude oil prices.[24] Accordingly, for analytical purposes, it is necessary to assume that rail unloading facilities at a port, from which crude oil can be shipped to overseas markets, becomes available so as to avoid a market price collapse. Muse has assumed that such facilities would be located in a British Columbia port, primarily because they are the closest ports to Alberta and railways are already built to several British Columbia ports.[25] There are analytical alternatives. It could be assumed that the port facilities would be located on the Gulf Coast or somewhere on the east coast of North America. For example, the press has reported that Canadian heavy crude oil has been railed to the Montreal area, and shipped via tanker to destinations in Italy and the Gulf

[24] Muse has not attempted to assess the exact year in which complete saturation would be reached using the CAPP 2015 crude oil supply forecast, but it appears that by about 2030 such a point would be reached in the Base Scenario (no TMEP).

[25] For purposes of calculating the tanker costs, Muse has used Kitimat as the load port. The specific port assumption (Kitimat, Prince Rupert, Vancouver, or a port in Washington State) is not particularly critical for the analysis. The vessel size assumption (Aframax, Suezmax, etc.) has more influence on the voyage cost to overseas markets than the port assumption.

Coast.[26] However, all of these alternatives to reach overseas markets would incur higher rail and tanker costs. Since the commissioning of TMEP will reduce the volume of Western Canadian crude oil that must be transported by rail, using the lowest cost rail alternative (to British Columbia) to overseas markets provides a more conservative estimate of the TMEP benefits to the Canadian crude oil producers.

The key assumptions regarding rail transport are:

- Total effective Western Canada rail loading capacity in 2018 is 87,400 m^3/d (550 kb/d), growing to 615,300 m3/d (3,870 kb/d) by 2038.

- Total rail unloading capacity at west coast ports, for further transportation by tanker to the Pacific Basin markets, is assumed to be 3,800 m^3/d (25 kb/d) in 2018, and grows to 127,200 m^3/d (800 kb/d) by 2038. The tanker cost from Kitimat to the various Pacific markets is used.

- Total effective rail unloading capacity on the Gulf Coast is estimated to be 61,200 m^3/d (385 kb/d) in 2018, and grows to 336,300 m^3/d (2,115 kb/d) by 2038. Slightly different rail costs are used for the Houston, Beaumont/Port Arthur, and Louisiana markets.

- Total effective rail unloading capacity for crude oil at the Puget Sound area refineries is assumed to be 41,500 m^3/d (261 kb/d) in 2018, and grows to 61,400 m^3/d (386 kb/d) by 2038.

[26] Bloomberg News, 9-24-2014, *"Suncor Looks East for Buyers of Canadian Oil."*

- Total effective rail loading capacity for Bakken crude is estimated to be 131,200 m^3/d (825 kb/d) in 2018, and remains unchanged through 2038.

Rail costs appropriate for the transportation of fully diluted Canadian heavy crude oil (such that they are suitable for pipeline transportation) has been used for this analysis. Muse is aware of both the potential for and current experience with transporting semi-diluted, or un-diluted, crude oil via rail. However, in Muse's opinion the transport of semi-diluted or un-diluted heavy crude oil by rail will continue to be very limited. The receipt of such crude oils requires specialized rail unloading facilities that have steaming capabilities, which is both more manpower intensive and costly. Customized facilities are also required in Canada to load such crude oils. Particularly for un-diluted heavy crude oil, the addition of diluent is typically required before the crude oil can be processed in a refinery, which further adds to cost and operating complexity. Finally, a crude oil producer that is contemplating a strategy of selling un-diluted heavy crude oil is generally compelled to enter into a long-term sales contract with one of the few counterparties that have access to a steam-capable rail unloading facility. Such a requirement greatly limits the market optionality and diversification available to the Canadian crude oil producer.

Pipeline tolls and rates are obtained from NEB, FERC, and state tariff filings. The nominal TMEP tolls (in 2018 dollars) were provided by Trans Mountain Pipeline. Appendix Table A-2 provides both the nominal TMEP tolls and Muse's translation to a real (2015 dollars) toll. The nominal toll estimates are deflated to 2015 dollars using an annual inflation rate of 2.1 percent.[27] For the existing Trans Mountain Pipeline, NEB Tariff No. 97 is used.[28] The barge and rail costs are based on Muse's industry experience and research.

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[27] The Canadian/U.S. exchange rate is assumed to be 1.0/1.0.

[28] The Tank Metered Light toll is used for light and medium crude oil shipments, and the Tank Metered Super Heavy toll is used for all heavy crude oil shipments.

All pipeline volume commitments are modeled as shipments that can take place at discounted tolls, rather than as minimum throughput obligations. This more closely mimics actual market behavior, in that it recognizes that committed shippers incur low incremental cash costs to ship, but are not obligated to physically ship the barrels.

Appendix Table A-3 provides the estimate of the cost to transport Canadian crude oil to key Northeast Asia and West Coast markets via tanker from Westridge, exclusive of physical loss and insurance costs, which are a function of the oil price. For purposes of the modeling effort, shipment on an Aframax (80,000 DWT) class vessel to all Pacific Basin markets from Westridge is assumed. For purposes of assessing the delivered costs of the competing crude oil grades (from the Middle East, Africa, etc.) in Northeast Asia, a VLCC-class vessel has been used.

REFINERY CAPACITY

Within the Crude Oil Market Optimization Model, most refineries located in Canada, the Puget Sound area, the Midwest, and the Mid-Continent are individually represented. Most refineries located in Northern China, Southern China, Japan, Korea, Taiwan, Gulf Coast, the Rockies, and California are represented as a number of aggregates, rather than as individual refineries, mostly due to the large number of refineries in these areas. It should be noted that only the High Capability and Medium Capability Northeast Asian refinery aggregates are explicitly included in the Crude Oil Market Optimization Model, and that the Low Capability aggregates (which are expected to process little Canadian crude oil) are not included. For U.S. refineries, crude oil capacities are obtained from the Energy Information Administration (EIA) Refinery Capacity 2015 Report, adjusted by Muse as appropriate to incorporate known capacity expansions.[29] Capacity information for other refineries is obtained from the *Oil & Gas Journal* 2014 Worldwide Refining Survey, frequently supplemented with information from company and other public sources.[30] Appendix Table A-4 provides the calendar day capacity of the refineries

[29] EIA, *Refinery Capacity 2015*, Table 3, "*Capacity of Operable Petroleum Refineries by State as of January 1, 2015.*"
[30] *Oil & Gas Journal,* December 1, 2014.

individually modeled, and the composition and capacity of the refinery aggregates used for 2018 in the Crude Oil Market Optimization Model. Muse has applied utilization factors, which vary somewhat by region and refinery, to the indicated calendar day capacities within the Crude Oil Market Optimization Model.

Only refineries in operation, or under construction, are included in the model. Muse has not attempted to estimate how refiners, particularly in China, may modify or expand individual refineries to accommodate greater volumes of Western Canadian crude oil. Such modifications are possible over time, much as the Midwestern and Ontario refineries have been upgraded over time to accept greater volumes of Western Canadian crude oil. Muse has assumed that the Chinese and Korean refinery configurations explicitly modeled will increase their overall capacity at a rate of 1 percent per year. The IEA is projecting that Chinese refining capacity between 2014 and 2020 will grow at a rate of 1.9 percent per annum, which equates to an absolute increase in refining capacity of 238,500 m^3/d (1,500 kb/d).[31] The North American, Japanese, and Taiwanese refinery capacities are held constant at their 2015 values.[32] These capacity assumptions are regarded as conservative.

CRUDE OIL REFINING VALUES

A key input variable to the Crude Oil Market Optimization Model is the value of various Western Canadian crude oils to the potential refinery customers. Muse refers to these crude oil values as the refining value. The refining values are developed by Muse via the use of highly complex refinery LP models. Muse licenses the AspenTech PIMS® modeling system, which is the same system used by over half of the North America refiners to optimize their refinery operations. The refiner's optimization objectives include crude oil selection, determining process unit run rates, and selecting the mix of refined products to be produced. The PIMS® models used by Muse are substantially identical to those used by the refiners themselves.

[31] IEA 2015 Medium-Term Oil Market Report, pg. 93.

[32] Refinery closures are anticipated in Japan, but these are expected to be concentrated in the Low Capability refining sector that is not included in the Crude Oil Market Optimization Model.

For each refinery, or refinery aggregate, of interest in the Canadian crude oil market area, a PIMS® model is constructed using public information regarding individual process unit capacities and capabilities. A base case is established whereby the refinery is fully utilizing the key process units using a combination of domestic crude oils and waterborne imports. Next, increasing volumes of the various Canadian crude oil grades are input to the model, backing out some volume of the refiner's crude oil alternatives, thus developing an understanding of the value to the refiner of the Canadian crude oil as a function of the Canadian crude oil's throughput.[33] The value of any crude oil grade typically decreases as its throughput increases, as all refineries generally experience diminishing returns as greater volumes of any specific crude oil grade are processed. This can be because key process unit constraints require the sale of lower-valued intermediate products, various product specifications are becoming increasing difficult to satisfy, or key process units are not fully utilized. By developing an understanding of the value of Canadian crude oils as a function of the individual refinery throughput, the marketplace for Canadian crude oil is disaggregated into a much larger number of demand nodes than would be possible if the individual refineries were treated as if they had a single, fixed, demand for Canadian crude oil. This analytical approach improves the precision of the optimization model.

The development of the Canadian crude oil refining values with a refinery LP model requires a complete set of non-Canadian crude oil and refined product prices. The non-Canadian crude oil prices are important as they are the competitive alternative that is being displaced by the Canadian crude oil. Canadian crude oils also produce a slightly different set of refined products than the non-Canadian alternative, and thus the refined product prices are required to fully assess the refining value of the Canadian crude oils, although this tends to have a rather minor impact on the resultant refining values.

[33] Refining values are developed using the PIMS® models for Cold Lake Blend, Western Canadian Select, Athabasca DilBit, and Sweet Synthetic. Values for the conventional Canadian crude grades and sour synthetic are developed from correlations using the explicitly modeled grades.

CRUDE OIL AND PRODUCT PRICE FORECAST

For the analysis, Muse has used its standard crude oil and refined petroleum product price forecast, as of September 2015. Appendix Tables A-5 and A-6 provide the Gulf Coast refined product and key crude oil prices, respectively. Muse employs a proprietary methodology for the development of its price forecasts that is fundamentally based on five key market variables. These variables are:

1) Dated North Sea, which primarily establishes the absolute price level for all crude oils and products;[34]
2) Natural gas price at the Houston Ship Channel, which influences refinery operating costs and the liquid petroleum gases (LPG) to light product (gasoline, diesel, etc.) pricing relationships;
3) Contribution margin for a Gulf Coast cracking refinery, which primarily influences the light product to crude oil differential;
4) The contribution margin for a Gulf Coast coker, which primarily influences the light-heavy product differential; and,
5) The ultra-low sulfur diesel to unleaded regular differential.

These variables are used because they address the principal aspects of the refining industry and are comparatively independent of one another. The future values for these variables that Muse selects are informed both by the refining industry's historical experience, and Muse's analyses and opinions regarding its forward path. Once the five independent variables are selected, Muse's proprietary pricing models generate a unique set of Gulf Coast refined product, LPG, and intermediate feedstock prices that return the cracking refinery and coking margins required, and are consistent with the three other independent variables.

Muse's crude oil price forecasting methodology is based upon the principle that all crude oils that have their price established in a given market (Gulf Coast, Rotterdam,

[34] Industry frequently uses the term "Dated Brent" when discussing the Dated North Sea price.

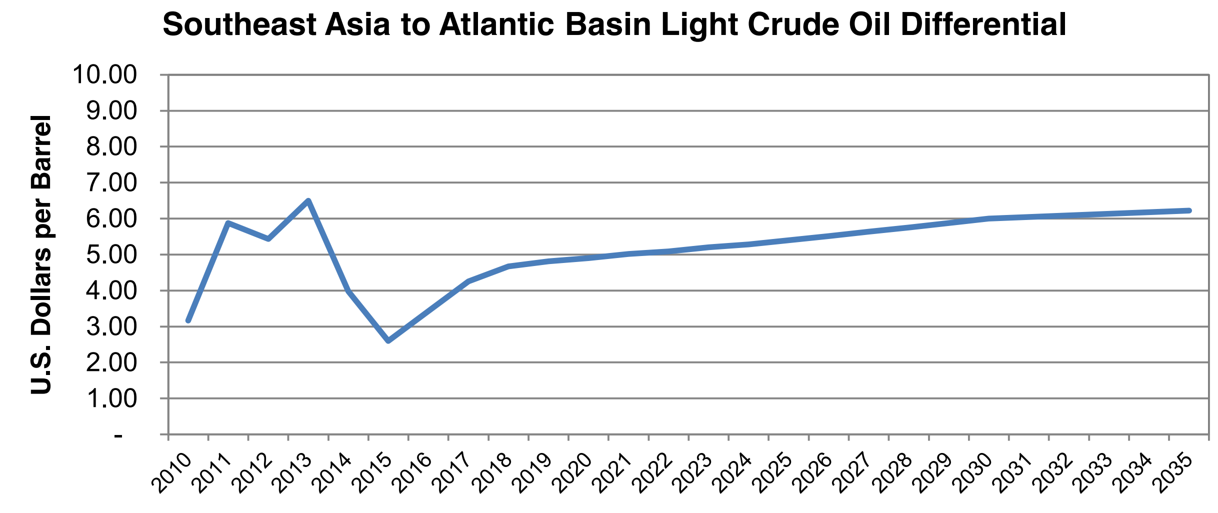
Singapore, etc.) must have the same refining margin.[35] For a refiner, the product yield of a crude oil, and the associated operating costs, is its primary determinant of value. Therefore, as part of its crude oil pricing methodology, Muse generates the product yields and variable operating costs representative of a typical Gulf Coast cracking refinery for a large number of crude oils. The contribution values for all crude oils of interest are then generated by multiplying the crude-specific product yield by the product prices, and subtracting the variable operating costs. The forecast price for all crude oils priced on the Gulf Coast then equals the contribution value less the desired contribution margin for a Gulf Coast cracking refinery. This methodology leaves the refiner indifferent between purchasing one crude oil versus another.

Singapore is used as the pricing location for most Asian crude oil and refined product prices by Muse. To develop a complete Singapore crude oil and refined product price forecast, Muse first establishes the price relationship between light sweet crude oil using Dated North Sea and Tapis, which is a Malaysian light sweet crude oil. It is Muse's view that Tapis will maintain its historical premium to Dated North Sea, particularly as West Africa and increasingly South America are acting as the incremental crude oil supply source for Asia. From West Africa or South America, the voyage distance to Asia is greater than it is to North America. Consequently, the delivered cost of West African and South American crude oil is higher in Asia than in the Atlantic Basin due to the higher freight costs.[36] The historical and Muse's forecast differential between Tapis (FOB Kikeh, Malaysia) and Dated North Sea is provided in Figure 23. It should be noted that the Singapore-to-North Sea differential would be about $0.90/bbl wider than that shown in Figure 23, as this is the approximate Tapis delivery cost from Kikeh to Singapore.

[35] If not, the refiner will buy the higher margin crude oil, increasing its price, and sell (or not buy) the lower margin crude oil, lowering its price, until the crude oil margins come back into equilibrium.

[36] The precise delivered cost for West African and South American crudes to both markets is influenced by vessel size assumptions, the specific load port (which varies by crude grade), and the Asian discharge port.

Figure 23



Source: Argus, Muse

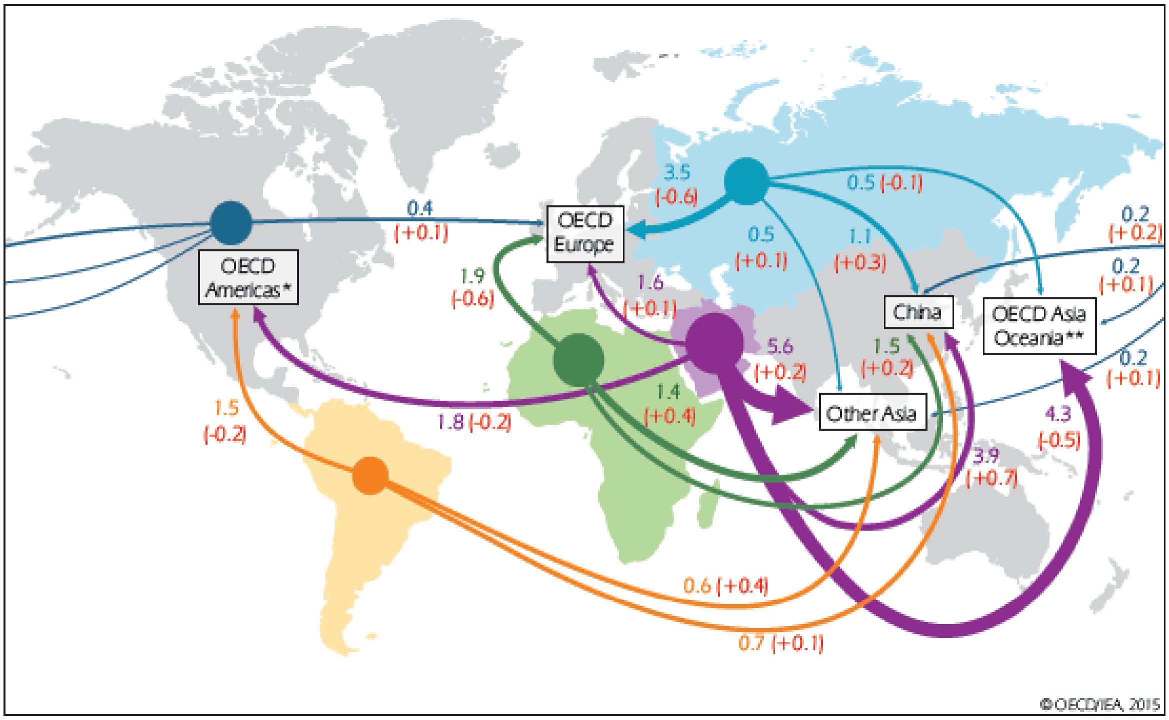
The direction of the trade flows between the Atlantic and Pacific Basins is clearly articulated by the International Energy Agency (IEA). In its *Medium-Term Oil & Gas Markets 2015* report, the IEA provides a forecast of crude oil trade flows around the world.[37] The IEA projection, shown below as Figure 24 below, provides both the estimated crude oil exports in 2020 for Africa and South America and the change in crude oil exports for the period 2014 to 2020 for key trade routes. A notable aspect of the IEA forecast is that crude oil deliveries from Africa to North America have effectively ceased, and that exports from South America to the Pacific Basin are expected to grow strongly. Crude oil shipments from South America to China and Other Asia are forecast to increase by 15,900 m^3/d (100 kb/d) and 63,600 m^3/d (400 kb/d), respectively. As the freight costs must always be paid, the rising flows of South American crude oil to Asia require higher delivered crude oil prices in Asia or lower crude oil prices at the South American load ports. Either way, higher flows from both Africa and South America to Asia widen the crude oil price differential between Asia and North America. All else equal, higher delivered crude oil costs in Asia improve the competitiveness of Canadian

[37] International Energy Agency, Medium-Term Oil & Gas Markets 2015, pg.82.

crude oil exports from British Columbia, versus exporting Canadian crude oil into the U.S. market.

Figure 24

Crude Oil Exports in 2020 and Growth in 2014-2020 for Key Trade Routes



A complete set of Singapore refined product prices is developed in relation to the Tapis price forecast, via a series of refinery margin and product pricing relationships between the Gulf Coast and Singapore. The margin and product price relationships between the Gulf Coast and Singapore used by Muse reflect both the historical experience and Muse's analyses and opinions. To generate the prices for various Middle Eastern and most Asian crude oils at Singapore, a similar methodology as that used for the Gulf Coast crude oils is employed, but using the product yields, operating costs, and contribution margins for a typical Singapore refinery. Once the Singapore crude oil values are obtained, the load port prices for the various crude oils of interest are calculated by subtracting the applicable tanker freight and related fees. Consequently, the delivered price for a given crude oil to refineries in Asia-Pacific is then equal to the load port price plus the appropriate freight and fees to that location, e.g., South Korea.[38]

The refined product and crude oil prices for Singapore are provided in Appendix Tables A-7 and A-8, respectively. To develop the Canadian crude oil refining values in Northeast Asia employed in the Crude Market Optimization Model, the Singapore crude oil and product prices are translated to other Asian locations by applying the applicable freight and quality differentials.

It is critical that the Northeast Asian crude oil prices be high enough, relative to the Gulf Coast alternative, for crude oil to ship on TMEP, but once that threshold price differential is attained, the benefit of further increases in the Asia-Gulf Coast crude oil price differentials mostly flows to the shippers on TMEP and does not get simply expressed as higher crude oil prices at Edmonton. Once TMEP is full, higher Asian crude oil prices cannot further increase shipments on TMEP, and TMEP is no longer acting as the price-setting mechanism for Western Canadian crude oil. In the TMEP Scenario, TMEP is always full, and some other transportation mode and perhaps market must be acting as the price-setting mechanism for Western Canadian crude oils.

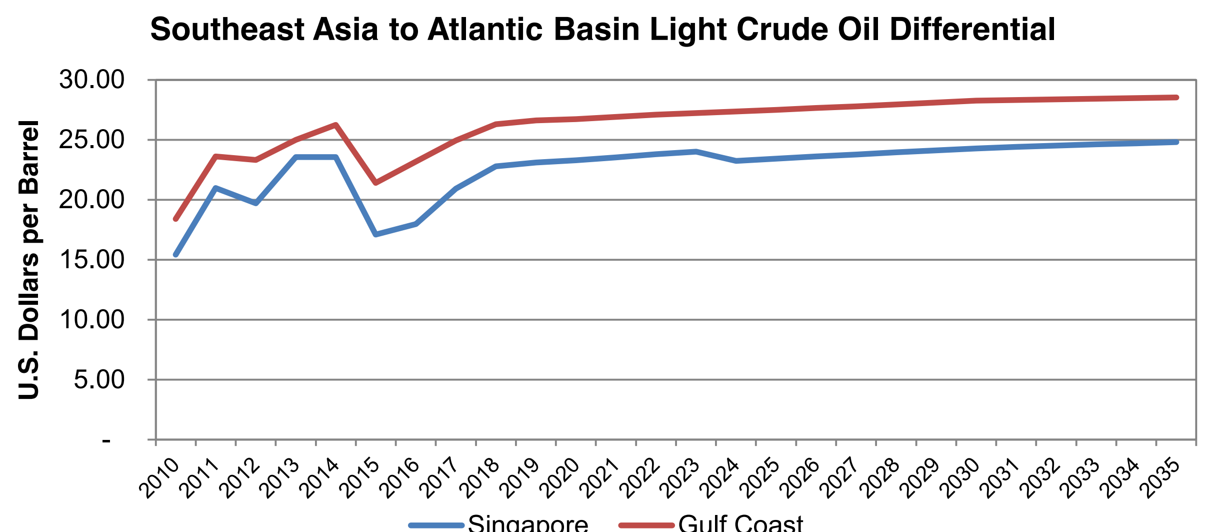
As Western Canada is one of the largest producers of heavy crude oil in the world today, with the prospect of very large supply increases, the pricing relationships between Asia and the Gulf Coast for heavy crude oils are important to TMEP. Unlike the case for the light crude oil price differential between Singapore and the Gulf Coast, Muse does not directly establish a heavy crude oil price differential between these two regions. Instead, refined product pricing relationships and refining economics are used to establish the light-heavy crude oil differentials in each market, which in turn sets the resultant heavy crude oil price differentials between the two regions. Generally, the light-heavy product differential is the most important price relationship for determining the light-heavy crude oil price differential. This is because light and heavy crude oils

[38] Certain crude oils are priced in Northeast Asia rather than Singapore.

produce differing amounts of light and heavy refined products, and refiners are highly sensitive to such yield differences.

All else equal, narrower light-heavy product differentials in Singapore will act to reduce the price differential between light and heavy crude oil grades in Singapore versus that on the Gulf Coast. Figure 22 provides the historical and the Muse forecast light-heavy product differentials for the Gulf Coast and Singapore.[39] As can be observed from Figure 25, Singapore historically has had narrower light-heavy product differentials than that of the Gulf Coast.

Figure 25



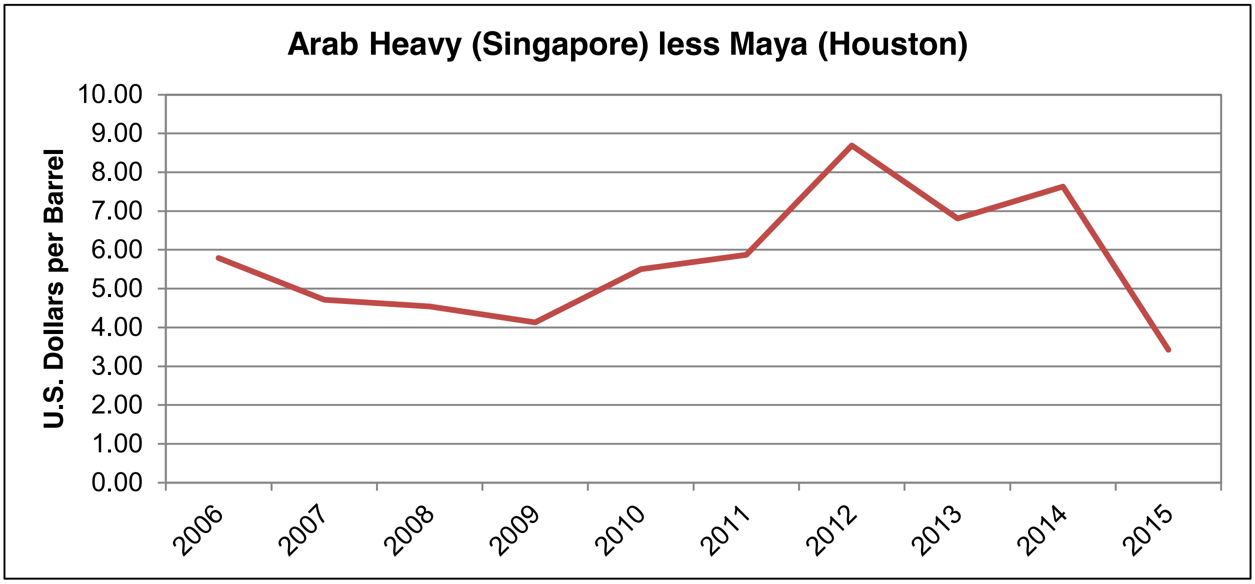
Source: Argus, Muse

Figure 26 below provides some perspective on the price differentials between the Atlantic and Pacific Basins for similar crude oil grades that result from the regional product price relationships. Since 2006 through July 2015, Arab Heavy delivered to Singapore has cost $5.71 per barrel (/bbl) more than Maya delivered to Houston. These are both heavy sour crude oil grades. Maya is regarded by industry as the heavy

[39] The Gulf Coast light-heavy product differential equals ⅔ * conventional regular before oxygenate blending (CBOB) gasoline + ⅓ * ultralow sulfur diesel – No. 6 fuel oil 3%S. The Singapore light-heavy differential equals ½ * regular gasoline + ½ * 0.5%S gasoil – HSFO 180 cSt 3.5%S.

crude oil benchmark for the Gulf Coast, and Arab Heavy fills this role in the Asian markets.

Figure 26



ANALYTICAL RESULTS

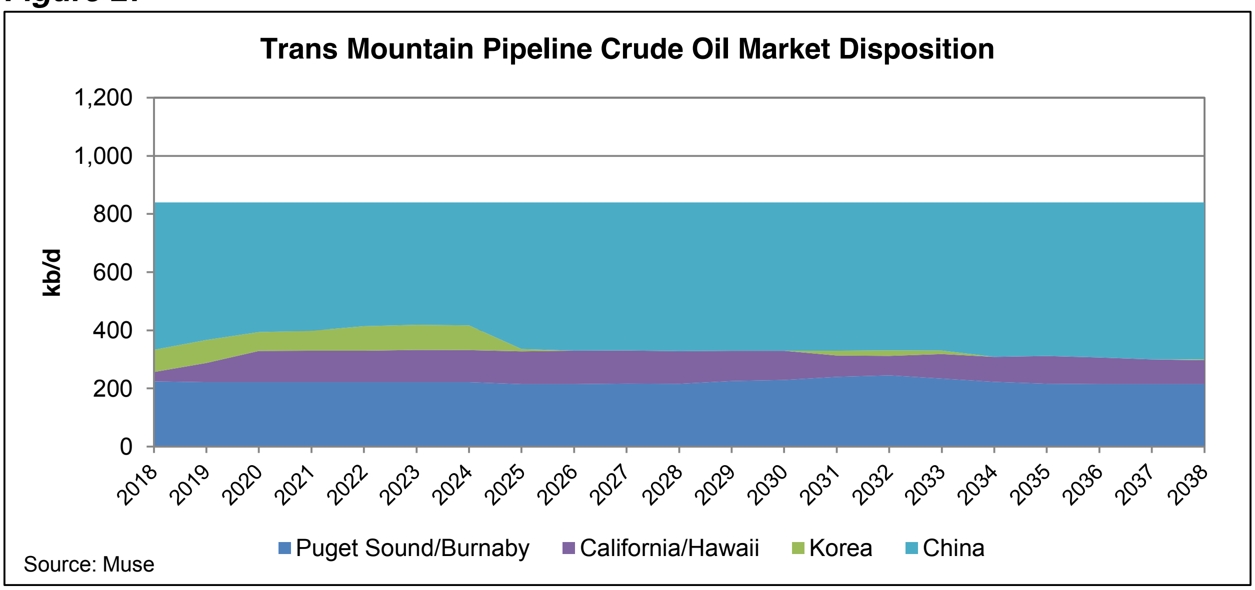
The output of the Crude Oil Market Optimization Model includes: (1) the throughput on each pipeline, barge, tanker, and rail route; (2) the disposition of Western Canadian crude oil by market; (3) the disposition of U.S. crude oil by market; (4) refinery throughput; and, (5) the value (price) of each Canadian crude oil grade. To calculate the benefit of TMEP, the Crude Market Optimization Model was run twice for the years 2018 through 2038, once with TMEP operational (the “TMEP Scenario”) and once without the TMEP (the “Base Scenario”). The only model input variable that differs between the Base Scenario and the TMEP Scenario is the commissioning of TMEP.

Canadian crude oil sellers do not have the ability to partition the market such that different crude oil buyers pay different prices for the same grade of crude oil. Accordingly, the assessment of the price of all Canadian crude oil grades is based upon the principle that the last barrel of each grade sold establishes the market price for the entire volume of each grade. One of the attributes of the type of optimization model used by Muse is that it can report the marginal value (also referred to as the shadow price or dual value) of the last barrel of each grade of Canadian crude oil supplied to the market. Consequently, the marginal value for the individual Canadian crude oil grades equals the predicted market price for Canadian crude oil grades. Therefore, the pricing implications of changing a model input variable can be assessed by comparing the marginal values between model runs.

Western Canadian Crude Oil Shipments – Appendix Table A-9 provides the composition of the crude oil throughput on the Trans Mountain Pipeline, plus similar information for the other pipelines transporting crude oil from Western Canada. Also shown in Appendix Table A-9 are the forecast volumes of crude oil shipped from Western Canada via rail.

Western Canadian Crude Oil Market Disposition – Figure 27 provides the market disposition forecast for the Canadian crude oil transported by the Trans Mountain Pipeline. The sales into Northeast Asia are predominantly heavy crude oil, and the sales in the other markets are mostly light crude oil.

Figure 27



Appendix Tables A-10 and A-11 provide the disposition of Western Canadian conventional light and medium plus the synthetic crude oil grades by market, with and without TMEP, respectively. It should be noted that all of the Western Canadian crude oil production in the Base Scenario can be shipped to a refinery somewhere and, accordingly, the TMEP benefit estimate does not include any credit for the avoidance of crude oil production shut-in. Appendix Tables A-12 and A-13 provide the disposition of the Canadian heavy crude oil grades by market, with and without TMEP, respectively.

Canadian Crude Oil Pricing – The startup of TMEP will act to increase the price of crude oil at Edmonton because roughly 79,500 m^3/d (500 kb/d) of crude oil is diverted from the existing North American markets to Northeast Asia and less rail transport is required. Appendix Tables A-14 and A-15 provide the estimated price at Edmonton for the various grades of Canadian crude oil with and without TMEP, respectively.

In general, prior to about 2024, TMEP greatly reduces the need to transport sizable volumes of Western Canadian heavy crude oil via rail to market. The combination of the market expansion to Northeast Asia, with the concomitant reduction of supply to North America, and avoidance of comparatively expensive rail transport acts to considerably improve the overall netbacks for the Canadian heavy crude oil producers. It should also be noted that TMEP also increases the access of the Canadian light crude oil producers to the Puget Sound, California, and Northeast Asia markets by about 15,900 m^3/d (100 kb/d). In subsequent years, rail transport will be required to transport a portion of the Western Canadian crude oil production even with TMEP. At this point, the per-barrel benefits of TMEP decrease from that generated in the early years as TMEP is in effect only reducing the supply of Canadian crude oil to the finite North American markets. Nonetheless, the per-barrel benefits remain appreciable.

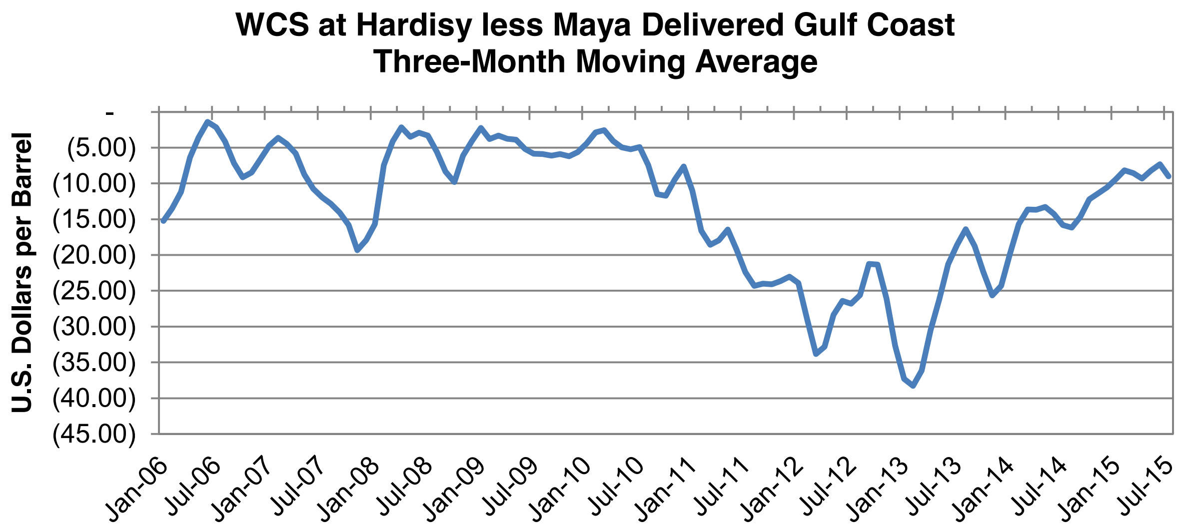
Canadian Crude Oil Producer Benefit Estimate – Since the Canadian crude oil supply volume is the same with and without TMEP, the calculation of the benefit to the Canadian crude oil producers is made by multiplying the change in Canadian crude oil prices (by grade) by the corresponding volume of the Canadian crude oil grades.

Appendix Table A-16 provides the details in 2015 dollars. Appendix Table A-17 converts the 2015 dollar estimate to 2012 dollars, using an inflation factor provided by the Conference Board of Canada.

Appendix Table A-17 also provides the present value of the estimated benefits to the Canadian crude oil producers over a range of discount rates. Using a 5 percent real discount rate, in 2015 the present value of TMEP is approximately CA$38 billion (2012$) through 2038, and the benefits will continue after 2038. On an undiscounted basis, the value of the Canadian oil industry benefits is about CA$73.5 billion (2012$) through 2038.

Potential Market Diversification and Optionality Benefits – Canadian crude oil producers have intermittently struggled with severe market disequilibrium. Figure 28 displays the historical pricing relationship between two heavy sour crude oils that compete in the North American crude oil markets. Western Canadian Select (WCS) at Hardisty is the benchmark heavy crude oil in Canada, and Maya fills that role on the Gulf Coast. The Maya price has been adjusted by Muse to incorporate the freight costs between Mexico and the Gulf Coast. To a refiner, WCS and Maya have similar refining values. It also should be noted that since WCS and Maya are both heavy crude oils, shifts in the global light-heavy crude differentials would equally affect each. Severe market disequilibrium is observable in the Canadian heavy crude oil market for much of 2012 and 2013. In Muse's professional opinion, this disequilibrium is primarily due to the lack of market diversification available to the Canadian crude oil producers. Projects such as TMEP offer the Canadian crude oil producer precisely the diversification that they lacked in 2012-2013.

Figure 28



Source: Argus, Muse

The reasonableness of the key analytical assumptions regarding supply, demand, competition, and transportation costs has been carefully evaluated for this report. The key assumptions include:

Demand – The Northeast Asia demand potential is based upon the region's current capabilities, rather than one in which refineries, particularly in China, have been built or customized to process Canadian crude oils.

- **Supply** – The Western Canadian crude oil supply used in the model is based upon the CAPP June 2015 forecast. In the latter half of 2014, crude oil prices dropped precipitously. It is with this as a backdrop that CAPP developed its 2015 forecast, and it is consistent with the industry's latest, and lower, views on the forward price for oil.

- **Transportation Options** – Ample rail loading and unloading capacity is provided to enable Western Canadian crude oil to reach the North American and overseas markets. The estimated benefits of TMEP are not based upon the avoidance of shut-in of Western Canadian crude oil.

It is Muse’s professional judgment that the key assumptions used to generate the analytical results presented in this report are reasonable and well founded.

APPENDIX A — TABLES

T A B L E A - 1

WESTERN CANADIAN CRUDE OIL SUPPLY

CAPP 2015 SUPPLY OUTLOOK PLUS MUSE EXTENSION

(Thousands of Barrels per Day, Unless Noted)

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*	*2031*	*2032*	*2033*	*2034*	*2035*	*2036*	*2037*	*2038*
Canadian Light Sweet	464	448	439	433	432	435	439	441	444	447	449	452	456	460	464	467	470	474	477	481	484	486	488	490
Canadian Medium Sour	309	299	292	289	288	290	293	294	296	298	300	302	304	307	310	311	313	316	318	321	323	324	325	327
Light Synthetic	796	820	844	918	929	964	977	982	968	951	932	916	908	1,012	1,038	1,070	1,099	1,130	1,162	1,194	1,227	1,244	1,262	1,279
Total Light	**1,569**	**1,566**	**1,575**	**1,639**	**1,648**	**1,690**	**1,709**	**1,717**	**1,708**	**1,696**	**1,681**	**1,669**	**1,668**	**1,779**	**1,812**	**1,847**	**1,883**	**1,919**	**1,957**	**1,995**	**2,035**	**2,055**	**2,075**	**2,096**
Conventional Heavy (LLB)	360	357	357	350	341	327	312	298	288	282	276	271	266	263	260	257	254	250	247	243	240	238	237	235
Western Canadian Select	325	350	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375
Cold Lake Blend	549	560	571	582	594	606	606	606	606	606	606	606	606	606	606	606	606	606	606	606	606	606	606	606
Athabasca SynBit	190	208	234	231	246	214	226	251	282	382	514	558	576	574	718	850	856	866	880	898	923	989	1,064	1,150
Athabasca DilBit	883	1,043	1,178	1,389	1,490	1,577	1,651	1,719	1,813	1,845	1,866	1,929	2,008	2,064	1,981	1,933	2,017	2,100	2,181	2,258	2,332	2,313	2,285	2,246
Sour Synthetic	120	120	120	130	132	134	137	139	139	144	150	151	151	164	177	190	194	199	204	209	215	222	229	237
Total Heavy	**2,426**	**2,637**	**2,835**	**3,057**	**3,177**	**3,233**	**3,306**	**3,388**	**3,503**	**3,633**	**3,786**	**3,889**	**3,982**	**4,045**	**4,117**	**4,210**	**4,302**	**4,396**	**4,492**	**4,590**	**4,691**	**4,743**	**4,796**	**4,849**
Total Western Canada	**3,995**	**4,204**	**4,410**	**4,696**	**4,825**	**4,922**	**5,015**	**5,105**	**5,211**	**5,329**	**5,467**	**5,558**	**5,650**	**5,824**	**5,929**	**6,058**	**6,185**	**6,315**	**6,449**	**6,586**	**6,726**	**6,798**	**6,871**	**6,945**

T A B L E   A - 2

TRANS MOUNTAIN PIPELINE TOLL CALCULATION

(Canadian Dollars per Barrel, Unless Noted)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Nominal (2018$)																					
Light Committed																					
Burnaby	4.15	4.16	4.26	4.37	4.47	4.58	4.70	4.81	4.93	5.05	5.18	5.30	5.44	5.57	5.71	5.85	5.99	6.14	6.29	6.45	6.61
Westridge	4.63	4.64	4.76	4.87	4.99	5.12	5.24	5.37	5.51	5.64	5.78	5.92	6.07	6.22	6.37	6.53	6.69	6.86	7.03	7.20	7.38
Sumas	3.97	3.98	4.08	4.18	4.28	4.39	4.50	4.61	4.72	4.84	4.96	5.08	5.20	5.33	5.46	5.60	5.74	5.88	6.02	6.17	6.33
Light Spot																					
Burnaby	5.10	5.11	5.24	5.37	5.50	5.63	5.77	5.92	6.06	6.21	6.37	6.52	6.69	6.85	7.02	7.19	7.37	7.55	7.74	7.93	8.13
Westridge	5.71	5.72	5.86	6.00	6.15	6.30	6.46	6.62	6.78	6.95	7.12	7.30	7.48	7.66	7.85	8.05	8.25	8.45	8.66	8.88	9.10
Sumas	4.88	4.89	5.01	5.13	5.26	5.39	5.53	5.66	5.80	5.95	6.09	6.24	6.40	6.56	6.72	6.88	7.05	7.23	7.41	7.59	7.78
Heavy Committed																					
Burnaby	4.22	4.23	4.33	4.44	4.55	4.66	4.77	4.89	5.01	5.13	5.26	5.39	5.52	5.66	5.80	5.94	6.09	6.24	6.39	6.55	6.71
Westridge	4.70	4.71	4.83	4.95	5.07	5.19	5.32	5.45	5.59	5.72	5.87	6.01	6.16	6.31	6.47	6.63	6.79	6.96	7.13	7.30	7.48
Sumas	4.04	4.05	4.15	4.25	4.36	4.46	4.57	4.69	4.80	4.92	5.04	5.17	5.29	5.42	5.56	5.69	5.83	5.98	6.12	6.27	6.43
Heavy Spot																					
Burnaby	5.17	4.83	4.95	5.07	5.19	5.32	5.45	5.59	5.73	5.87	6.01	6.16	6.31	6.47	6.63	6.79	6.96	7.13	7.30	7.49	7.67
Westridge	5.78	5.78	5.93	6.07	6.22	6.38	6.54	6.70	6.86	7.03	7.21	7.38	7.57	7.75	7.95	8.14	8.34	8.55	8.76	8.98	9.20
Sumas	4.95	4.96	5.08	5.21	5.34	5.47	5.60	5.74	5.88	6.03	6.18	6.33	6.48	6.64	6.81	6.98	7.15	7.33	7.51	7.69	7.88
Real (2015$)																					
Light Committed																					
Burnaby	3.90	3.83	3.84	3.85	3.87	3.88	3.90	3.91	3.92	3.94	3.95	3.97	3.98	3.99	4.01	4.02	4.04	4.05	4.07	4.08	4.10
Westridge	4.35	4.27	4.29	4.30	4.32	4.33	4.35	4.37	4.38	4.40	4.41	4.43	4.44	4.46	4.48	4.49	4.51	4.53	4.54	4.56	4.58
Sumas	3.73	3.66	3.68	3.69	3.70	3.72	3.73	3.74	3.76	3.77	3.78	3.80	3.81	3.82	3.84	3.85	3.87	3.88	3.89	3.91	3.92
Light Spot																					
Burnaby	4.79	4.70	4.72	4.74	4.75	4.77	4.79	4.81	4.82	4.84	4.86	4.88	4.90	4.91	4.93	4.95	4.97	4.99	5.00	5.02	5.04
Westridge	5.36	5.26	5.28	5.30	5.32	5.34	5.36	5.38	5.40	5.42	5.44	5.46	5.48	5.50	5.52	5.54	5.56	5.58	5.60	5.62	5.64
Sumas	4.59	4.50	4.52	4.53	4.55	4.57	4.58	4.60	4.62	4.63	4.65	4.67	4.68	4.70	4.72	4.74	4.75	4.77	4.79	4.80	4.82
Heavy Committed																					
Burnaby	3.96	3.89	3.90	3.92	3.93	3.95	3.96	3.97	3.99	4.00	4.02	4.03	4.04	4.06	4.07	4.09	4.10	4.12	4.13	4.15	4.16
Westridge	4.42	4.34	4.35	4.37	4.38	4.40	4.41	4.43	4.44	4.46	4.48	4.49	4.51	4.53	4.54	4.56	4.57	4.59	4.61	4.62	4.64
Sumas	3.80	3.73	3.74	3.75	3.77	3.78	3.79	3.81	3.82	3.83	3.85	3.86	3.87	3.89	3.90	3.92	3.93	3.94	3.96	3.97	3.99
Heavy Spot																					
Burnaby	4.86	4.44	4.46	4.47	4.49	4.51	4.52	4.54	4.56	4.57	4.59	4.60	4.62	4.64	4.65	4.67	4.69	4.70	4.72	4.74	4.76
Westridge	5.43	5.32	5.34	5.36	5.38	5.40	5.42	5.44	5.46	5.48	5.50	5.52	5.54	5.56	5.58	5.60	5.62	5.64	5.66	5.68	5.70
Sumas	4.65	4.56	4.58	4.60	4.61	4.63	4.65	4.66	4.68	4.70	4.71	4.73	4.75	4.76	4.78	4.80	4.82	4.83	4.85	4.87	4.89

Note: General Inflation = 2.1%

T A B L E A - 3

VOYAGE COSTS FROM WESTRIDGE MARINE TERMINAL

(U.S. Dollars per Barrel, Unless Noted)

	Barrels per Metric Ton	*World Scale Flat Rate $/MT*	*Spill Tax & Other*	*>=2018 Tug Fee $/B*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*	*2031*	*2032*	*2033*	*2034*	*2035*	*2036*	*2037*	*2038*
Escort Tug Fees, US$ per port call				60,000																					
Percent of Worldscale																									
80k DWT NA West Coast					112.32	113.51	114.38	115.30	116.18	117.08	117.97	118.87	119.77	120.64	121.51	122.39	123.27	123.70	124.13	124.56	124.99	125.42	125.85	126.29	126.72
80k DWT Voyage Cost Westridge																									
Synthetic																									
Jamnagar	7.36	39.20	0.22	0.16	6.36	6.43	6.47	6.52	6.57	6.62	6.66	6.71	6.76	6.81	6.85	6.90	6.95	6.97	6.99	7.02	7.04	7.06	7.08	7.11	7.13
Southern China (Quanzhou)	7.36	23.10	0.21	0.10	3.83	3.87	3.90	3.93	3.95	3.98	4.01	4.04	4.07	4.09	4.12	4.15	4.18	4.19	4.20	4.22	4.23	4.24	4.26	4.27	4.29
Northern China (Tsingtao)	7.36	21.99	0.21	0.10	3.66	3.70	3.73	3.75	3.78	3.81	3.83	3.86	3.89	3.91	3.94	3.96	3.99	4.00	4.02	4.03	4.04	4.06	4.07	4.08	4.09
Japan (Chiba)	7.36	19.46	0.21	0.10	3.28	3.31	3.33	3.36	3.38	3.40	3.43	3.45	3.47	3.50	3.52	3.54	3.57	3.58	3.59	3.60	3.61	3.62	3.64	3.65	3.66
Korea (Yosu)	7.36	20.19	0.21	0.10	3.39	3.42	3.45	3.47	3.49	3.52	3.54	3.57	3.59	3.62	3.64	3.67	3.69	3.70	3.71	3.72	3.74	3.75	3.76	3.77	3.78
Taiwan (Kaohsiung)	7.36	22.95	0.21	0.10	3.81	3.85	3.87	3.90	3.93	3.96	3.99	4.01	4.04	4.07	4.10	4.12	4.15	4.17	4.18	4.19	4.21	4.22	4.23	4.25	4.26
Anacortes	7.36	4.33	0.35	0.10	1.11	1.12	1.13	1.13	1.14	1.14	1.15	1.15	1.16	1.16	1.17	1.17	1.18	1.18	1.18	1.19	1.19	1.19	1.19	1.20	1.20
Los Angeles	7.36	7.91	0.35	0.10	1.66	1.67	1.68	1.69	1.70	1.71	1.72	1.73	1.74	1.75	1.76	1.77	1.78	1.78	1.79	1.79	1.80	1.80	1.81	1.81	1.81
San Francisco	7.36	6.90	0.35	0.10	1.51	1.52	1.52	1.53	1.54	1.55	1.56	1.57	1.58	1.58	1.59	1.60	1.61	1.61	1.62	1.62	1.62	1.63	1.63	1.64	1.64
Hawaii	7.36	12.17	0.35	0.10	2.31	2.33	2.34	2.36	2.37	2.39	2.40	2.42	2.43	2.45	2.46	2.48	2.49	2.50	2.51	2.51	2.52	2.53	2.53	2.54	2.55
Cold Lake Blend																									
Jamnagar	6.77	39.20	0.24	0.18	6.92	6.99	7.04	7.09	7.14	7.19	7.24	7.30	7.35	7.40	7.45	7.50	7.55	7.58	7.60	7.63	7.65	7.68	7.70	7.73	7.75
Southern China (Quanzhou)	6.77	23.10	0.22	0.11	4.17	4.21	4.24	4.27	4.30	4.33	4.36	4.39	4.42	4.45	4.48	4.51	4.54	4.55	4.57	4.58	4.60	4.61	4.63	4.64	4.66
Northern China (Tsingtao)	6.77	21.99	0.22	0.11	3.98	4.02	4.05	4.08	4.11	4.14	4.17	4.19	4.22	4.25	4.28	4.31	4.34	4.35	4.37	4.38	4.39	4.41	4.42	4.44	4.45
Japan (Chiba)	6.77	19.46	0.22	0.11	3.56	3.60	3.62	3.65	3.67	3.70	3.73	3.75	3.78	3.80	3.83	3.85	3.88	3.89	3.90	3.91	3.93	3.94	3.95	3.96	3.98
Korea (Yosu)	6.77	20.19	0.22	0.11	3.68	3.72	3.75	3.77	3.80	3.83	3.85	3.88	3.91	3.93	3.96	3.98	4.01	4.02	4.04	4.05	4.06	4.07	4.09	4.10	4.11
Taiwan (Kaohsiung)	6.77	22.95	0.22	0.11	4.14	4.18	4.21	4.24	4.27	4.30	4.33	4.36	4.39	4.42	4.45	4.48	4.51	4.53	4.54	4.56	4.57	4.59	4.60	4.61	4.63
Anacortes	6.77	4.33	0.37	0.11	1.20	1.21	1.21	1.22	1.22	1.23	1.23	1.24	1.25	1.25	1.26	1.26	1.27	1.27	1.27	1.28	1.28	1.28	1.28	1.29	1.29
Los Angeles	6.77	7.91	0.37	0.11	1.79	1.81	1.82	1.83	1.84	1.85	1.86	1.87	1.88	1.89	1.90	1.91	1.92	1.92	1.93	1.93	1.94	1.94	1.95	1.95	1.96
San Francisco	6.77	6.90	0.37	0.11	1.62	1.64	1.64	1.65	1.66	1.67	1.68	1.69	1.70	1.71	1.72	1.73	1.74	1.74	1.74	1.75	1.75	1.76	1.76	1.77	1.77
Hawaii	6.77	12.17	0.37	0.11	2.50	2.52	2.54	2.55	2.57	2.58	2.60	2.62	2.63	2.65	2.66	2.68	2.70	2.70	2.71	2.72	2.73	2.73	2.74	2.75	2.76

MUSE STANCIL

T A B L E A - 4

REFINERY AND REFINERY AGGREGATE CRUDE CAPACITIES

(Barrels per Calendar Day, Unless Noted)

Refinery Owner and Location	Submarket Location	2018 Crude Capacity
Northwest Upgrading	Edmonton	77,000
Imperial Strathcona		189,000
Husky Prince George		10,250
Shell Scotford		100,000
Suncor Edmonton		143,000
Edmonton (Aggregate)	Edmonton	442,250
Husky Lloydminster	Lloydminster	23,000
Coop Regina	Regina	110,000
Calumet Superior	Northern Tier	38,000
Flint Hills Pine Bend	Northern Tier	290,000
Northern Tier Energy St. Paul	Northern Tier	98,500
Tesoro Mandan	Northern Tier	103,860
BP Whiting	Chicago	413,500
CITGO Lemont	Chicago	175,940
ExxonMobil Joliet	Chicago	238,600
BP-Husky Toledo	Toledo	152,000
Marathon Detroit	Toledo	130,000
PBF Toledo	Toledo	160,000
WRB Wood River	Wood River	314,000
CountryMark Mt. Vernon	Patoka	27,100
Marathon Catlettsburg	Patoka	277,000
Marathon Robinson	Patoka	242,000
Husky Lima	Lima	155,000
Marathon Canton	Lima	115,000
CVR Energy Coffeyville	Kansas	115,000
Holly-Frontier El Dorado	Kansas	138,000
Cenex McPherson	McPherson	86,000
Phillips 66 Ponca City	Ponca	200,000
WRB Borger	Borger	146,000
Holly-Frontier Navaho	Artesia	102,000
Holly-Frontier Tulsa	Tulsa	155,300
CVR Energy Wynnewood	Cushing	70,000
Valero Ardmore	Cushing	86,000
Alon Big Spring	West Texas	70,000
Delek Tyler	West Texas	60,000
Western El Paso	West Texas	122,000
Western Gallup	West Texas	25,500
Valero McKee	West Texas	168,000
Lion Oil El Dorado	El Dorado	83,000
CENEX Laurel		59,600
ExxonMobil Billings		60,000
Phillips 66 Billings		59,000
Billings (Aggregate)	Billings	178,600
Calumet Great Falls	Billings	10,000
Chevron Salt Lake City		50,000
Sinclair Rawlins		85,000
Wyoming Utah Coking (Aggregate)	Wyoming Utah	135,000
Big West Salt Lake City		30,500
Holly-Fronter Woods Cross		25,050
Sinclair Casper		24,500
Tesoro Salt Lake City		57,500
Wyoming Refining Newcastle		14,000
PADD IV Lt Sweet Cracking (Aggregate)	Wyoming Utah	151,550
Holly-Frontier Cheyenne	Wyoming Utah	47,000
Suncor Denver	Wyoming Utah	103,000
Chevron Burnaby	Burnaby	52,000
Phillips 66 Ferndale		101,000
Tesoro Anacortes		120,000
Puget Sound Cracking (Aggregate)	Puget Sound	221,000
BP Cherry Point	Puget Sound	221,000
Shell Anacortes	Puget Sound	145,000
Imperial Sarnia	Sarnia	120,800
Nova Corruna	Sarnia	30,000
Shell Sarnia	Sarnia	71,400
Suncor Sarnia	Sarnia	85,000
United Warren	Nanticoke	65,000

T A B L E A - 4

REFINERY AND REFINERY AGGREGATE CRUDE CAPACITIES

(Barrels per Calendar Day, Unless Noted)

Refinery Owner and Location	*Submarket Location*	*2018 Crude Capacity*
Imperial Nanticoke	Nanticoke	112,000
Suncor Montreal	Quebec	129,800
Irving St. John	Atlantic Canada	250,000
North Atlantic Come by Chance	Atlantic Canada	115,000
Valero Levis	Atlantic Quebec	215,000
Philadelphia Energy Solutions Philadelphia		335,000
Monroe Trainer		185,000
Philadelphia Light Sweet Cracking (Aggregate)	Philadelphia	520,000
PBF Energy Delaware City	Philadelphia	182,200
PBF Paulsboro	Philadelphia	160,000
Phillips 66 Linden	Linden	238,000
Axeon Specialty Paulsboro	Linden	38,000
ExxonMobil Torrance		149,500
Phillips 66 Los Angeles		139,000
Tesoro Wilmington		104,500
Valero Wilmington		78,000
Los Angeles California Heavy (Aggregate)	California	471,000
Phillips 66 Rodeo		120,200
Chevron Richmond		245,271
Tesoro Los Angeles		257,300
Chevron El Segundo		269,000
California Medium Sour Coking (Aggregate)	California	526,300
Shell Martinez		156,400
Tesoro Martinez		166,000
Valero Benicia		145,000
California High FCC (Aggregate)	California	467,400
Kern Bakersfield		26,000
Lunday South Gate		8,500
San Joaquin Bakersfield		15,000
Santa Maria Refining		9,500
California Other (Aggregate)	California	59,000
Hawaii	Hawaii	147,500
Alaska	Alaska	165,200
Houston Refining Houston		264,000
Phillips 66 Sweeny		247,000
USGC Extra Heavy Coking (Aggregate)	Houston	511,000
Deer Park Refining Deer Park		316,600
Valero Texas City		225,000
USGC Heavy Coking (Aggregate)	Houston	541,600
ExxonMobil Baytown		560,500
Marathon Galveston Bay		451,000
USGC Medium Coking (Aggregate)	Houston	1,011,500
Valero Houston	Houston	190,000
Valero Port Arthur	Beaumont Port Arthur	335,000
Motiva Port Arthur		603,000
Phillips 66 Westlake		260,000
Total Port Arthur		225,500
USGC Heavy Coking (Aggregate)	Beaumont Port Arthur	1,088,500
ExxonMobil Beaumont		344,600
CITGO Lake Charles		427,800
USGC Heavy Coking Low Hydrotreat (Aggregate)	Beaumont Port Arthur	772,400
Chevron Pascagoula	Pascagoula	330,000
Valero St. Charles	Lower Mississippi	215,000
Hunt Tuscaloosa	Mobile	72,000
Marathon Garyville		522,000
ExxonMobil Chalmette		192,500
USGC Heavy Coking (Aggregate)	Lower Mississippi	714,500
ExxonMobil Baton Rouge	Baton Rouge	502,500
Valero Meraux	Lower Mississippi	125,000
Motiva Norco	Lower Mississippi	238,000
Motiva Convent	Lower Mississippi	235,000
Phillips 66 Belle Chase	Belle Chase	247,000
Alon Krotz Springs		80,000
Calumet Sherveport		57,000
Placid Port Allen		75,000
USGC Sweet Cracking (Aggregate)	Baton Rouge	212,000

T A B L E A - 4

REFINERY AND REFINERY AGGREGATE CRUDE CAPACITIES

(Barrels per Calendar Day, Unless Noted)

Refinery Owner and Location	*Submarket Location*	*2018 Crude Capacity*
Shell Saraland	Mobile	80,000
Valero Three Rivers	South Texas	89,000
Calumet San Antonio	South Texas	16,800
CITGO Corpus Christi	Corpus Christi	157,500
Flint Hills Corpus Christi	Corpus Christi	330,000
Valero Corpus Christi	Corpus Christi	275,000
China National Petroleum Corp. Jinzhou		159,700
CNOOC Daxie Liwan PetChem		173,200
CNOOC Taizhou (Jiangsu)		32,500
CNOOC Shandong Haihua		21,600
Sinopec Shanghai Gaoqiao		277,400
Sinopec Jingmen		109,700
Sinopec Jinling		287,400
Sinopec Qilu		422,100
Sinopec Qingdao		212,900
Sinopec Wuhan		184,000
Sinopec Yangzi		175,600
Northern China High Conversion (Aggregate)	Northern China	2,056,100
China National Petroleum Corp. Dalian		436,400
China National Petroleum Corp. Daqang Petrochem		108,200
China National Petroleum Corp. Jinxi		149,000
Sinopec Anqing		192,900
Sinopec Changling		279,600
Sinopec Cangzhou		74,500
Sinopec Jinan		138,600
Sinopec Jiujiang		140,700
Sinopec Luoyang		216,500
Sinopec Shanghai		298,100
Sinopec Tianjin		281,400
Sinopec Zhenhai		497,900
WEPEC Dalian		216,500
Northern China Medium Conversion (Aggregate)	Northern China	3,030,300
China National Petroleum Corp. Gaofu		49,800
CNOOC Huizhou		255,500
Sinopec Beihai		12,800
Sinopec Maoming		287,400
Southern China High Conversion (Aggregate)	Southern China	605,500
Sinopec Fujian		259,800
Sinopec Guangzhou		339,900
Sinopec Hainan		173,200
Southern China Medium Conversion (Aggregate)	Southern China	772,900
Japan Energy Co. Mizushima, Okayama		194,940
Seibu Oil Co. Ltd. Yamaguchi		110,000
Toa Oil Co. Ltd. Mizue Factory, Kawasaki		64,000
Japan High Conversion (Aggregate)	Japan	368,940
Cosmo Oil Co. Ltd. Chiba		228,000
Fuji Oil Co. Ltd. Sodegaura		192,000
Idemitsu Kosan Co. Ltd. Chita, Aichi		152,000
Idemitsu Kosan Co. Ltd. Ichihara, Chiba		209,000
Idemitsu Kosan Co. Ltd. Tomakomai, Hokkaido		133,000
JX Nippon Oil & Energy Corp. Muroran		180,000
JX Nippon Oil & Energy Corp. Negishi		340,000
JX Nippon Oil & Energy Corp. Sendai		145,000
JX Nippon Oil & Energy Corp. Marifu, Yamguchi		127,000
Toa Oil Co. Ltd. Ohgimachi Factory, Kawasaki		110,000
Japan Medium Conversion (Aggregate)	Japan	1,816,000
GS-Caltex Yosu		785,000
S-Oil Corp. Onsan		669,000
SK Corp. Ulsan		840,000
Korea Medium Conversion (Aggregate)	Korea	2,294,000
Chinese Petroleum Corp. Kaohsiung		270,000
Formosa Petrochemical Co. Mailiao		540,000
Taiwan Medium Conversion (Aggregate)	Taiwan	810,000
India (Aggregate)	Taiwan	1,303,252
Grand Total		**32,354,063**

T A B L E   A - 5

U.S. GULF COAST PRODUCT PRICE FORECAST

(U.S. Currency in the Units as Noted)

		Historical (Nominal $)					*Projected (Real $)*									*Averages*		
	Units	*2010*	*2011*	*2012*	*2013*	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*2025*	*2030*	*2035*	*2010-14*	*2015-20*	*2021-35*
Reference Prices																		
Light Louisiana Sweet	$/B	82.73	112.28	111.70	107.41	96.80	56.15	66.17	75.32	80.05	82.07	83.47	91.41	99.54	102.84	102.19	73.87	95.34
Natural Gas at Henry Hub	$/MMbtu	4.40	4.01	2.76	3.704	4.35	2.98	3.38	3.90	4.31	4.66	4.99	5.57	5.81	5.95	3.84	4.04	5.68
Natural Gas-Houston Ship Channel	$/MMbtu	4.35	3.96	2.71	3.698	4.34	2.87	3.27	3.79	4.20	4.55	4.88	5.46	5.70	5.84	3.81	3.93	5.57
Refined Products																		
Conventional gasoline																		
ULS Reg 87	¢/G	207.0	277.4	285.56	273.0	253.6	159.1	182.5	203.6	214.6	219.0	221.68	238.9	256.7	263.6	259.29	200.10	247.46
ULS Prem 93	¢/G	217.1	294.5	313.75	303.4	278.9	177.2	201.8	223.9	235.6	240.2	242.9	260.9	279.5	286.6	281.52	220.28	269.83
CBOB Regular	¢/G	206.3	276.4	281.15	268.3	249.4	155.0	178.1	199.4	210.9	215.8	219.0	236.5	254.3	261.1	256.31	196.36	245.04
CBOB Premium	¢/G	215.4	290.9	305.05	294.9	274.9	170.7	195.0	217.2	229.3	234.4	237.7	255.8	274.4	281.4	276.24	214.03	264.73
Reformulated gasoline	¢/G																	
RBOB 83.7	¢/G	208.5	280.3	287.2	275.5	253.1	159.0	182.8	204.3	215.7	220.4	223.3	240.9	259.1	266.1	260.92	200.92	249.65
RBOB 91.4	¢/G	218.6	297.8	313.1	300.9	277.0	176.9	201.6	223.9	235.8	240.6	243.6	261.8	280.6	287.7	281.48	220.42	270.81
Jet fuel	¢/G	214.8	299.6	305.3	292.3	269.6	175.2	199.2	221.3	233.2	238.3	241.6	259.8	278.3	285.4	276.32	218.14	268.65
Distillate																		
Diesel (15 ppm)	¢/G	215.6	296.9	305.2	296.9	271.0	176.2	200.2	222.3	234.2	239.3	242.6	260.8	279.3	286.4	277.12	219.14	269.65
Diesel (500 ppm)	¢/G	211.8	292.5	298.7	287.3	262.3	171.8	195.4	217.0	228.6	233.5	236.7	254.4	272.7	279.6	270.54	213.85	263.19
No. 2 (5,000 ppm)	¢/G	209.9	291.3	298.7	286.9	259.5	170.7	194.2	215.7	227.3	232.1	235.2	252.8	271.0	277.9	269.26	212.53	261.57
Heavy Products																		
No.6 1%S	$/B	72.08	99.99	104.54	96.03	87.51	49.54	57.95	65.59	69.30	71.14	72.42	79.35	86.44	89.18	92.03	64.32	82.75
No.6 3%S	$/B	69.72	95.63	99.35	93.01	82.71	46.66	54.71	62.02	65.54	67.31	68.56	75.23	82.05	84.67	88.08	60.80	78.50
No.6 3.5%S	$/B	70.47	97.17	100.35	94.01	83.71	46.26	54.31	61.62	65.14	66.91	68.16	74.83	81.65	84.27	89.14	60.40	78.10
Asphalt	$/T	459.17	505.00	553.75	539.38	552.71	274.34	321.70	364.67	385.38	395.80	403.14	442.36	482.46	497.84	522.00	357.50	461.58
Asphalt	$/B	81.99	90.18	98.88	96.32	92.03	48.99	57.45	65.12	68.82	70.68	71.99	78.99	86.15	88.90	91.88	63.84	82.42
LPGs																		
Natural Gasoline	¢/G	183.4	233.8	215.2	213.28	198.7	113.6	133.9	152.4	162.4	166.2	169.2	185.1	201.8	206.1	208.88	149.63	192.65
Isobutane	¢/G	157.9	205.1	180.5	142.87	125.0	72.2	85.9	104.3	118.2	128.4	137.9	161.3	175.6	179.3	162.27	107.81	167.76
Normal Butane	¢/G	149.8	184.7	165.4	139.44	121.9	70.2	83.5	101.6	115.4	125.5	135.0	150.9	164.1	167.6	152.24	105.18	156.88
Propane	¢/G	116.5	145.8	100.2	100.07	104.1	59.0	70.2	82.7	88.7	94.4	101.1	118.5	128.1	130.9	113.34	82.68	121.80
Purity ethane	¢/G	59.9	76.4	39.7	26.01	26.8	18.4	22.1	28.2	30.7	35.8	39.4	43.8	46.2	47.3	45.76	29.08	44.90

T A B L E A - 6

U.S. GULF COAST CRUDE PRICE FORECAST

(U.S. Dollars per Barrel)

	Historical (Nominal $)					*Projected (Real $)*									*Averages*		
	2010	***2011***	***2012***	***2013***	***2014***	***2015***	***2016***	***2017***	***2018***	***2019***	***2020***	***2025***	***2030***	***2035***	***2010-14***	***2015-20***	***2021-35***
Reference Prices (FOB)																	
Domestic																	
LLS at St James	82.73	112.28	111.70	107.41	96.80	56.15	66.17	75.32	80.05	82.07	83.47	91.41	99.54	102.84	102.19	73.87	95.34
ANS at Long Beach	79.89	110.01	110.62	107.74	97.84	56.89	66.77	75.71	80.27	82.18	83.48	90.96	98.71	101.75	101.22	74.22	94.69
Mars at Clovelly	77.98	107.45	106.82	102.30	92.84	53.27	62.79	71.39	75.72	77.56	78.83	86.05	93.57	96.50	97.48	69.93	89.67
Poseidon at Houma	77.79	107.22	106.35	101.90	91.81	53.05	62.55	71.12	75.44	77.28	78.55	85.77	93.28	96.19	97.01	69.66	89.38
Bonito Sour	80.52	110.28	109.03	104.90	94.56	55.68	65.58	74.55	79.14	81.06	82.37	90.01	97.91	101.08	99.86	73.06	93.83
HLS	81.56	112.56	112.28	107.49	96.16	55.93	65.95	75.05	79.72	81.70	83.05	90.85	98.88	102.14	102.01	73.57	94.74
International																	
North Sea Dated	79.49	111.23	111.58	108.68	98.99	57.78	67.72	76.44	80.78	82.47	83.55	90.20	97.28	99.76	101.99	74.79	93.55
Maya at Cayo	70.24	98.65	99.58	97.33	85.80	47.18	56.08	64.04	67.90	69.60	70.76	77.49	84.52	87.21	90.32	62.59	80.86
Dubai at Fateh	78.04	106.19	108.89	105.48	96.54	53.08	63.52	72.15	76.35	78.07	79.18	86.21	93.58	96.10	99.03	70.39	89.65
Tapis at Kerteh	82.65	117.11	117.01	115.18	102.97	60.38	71.16	80.69	85.45	87.28	88.46	95.59	103.28	105.98	106.98	78.90	99.25
Arab Light (to U.S.)	77.46	107.43	106.91	102.90	94.79	52.03	61.60	70.24	74.61	76.42	77.66	84.92	92.49	95.44	97.90	68.76	88.56
Arab Heavy (to U.S.)	74.32	103.24	102.86	98.81	90.89	46.96	56.09	64.36	68.50	70.32	71.60	78.73	86.09	88.97	94.02	62.97	82.27
Prices at USGC, Delivered																	
Domestic																	
Light Louisiana Sweet	82.73	112.28	111.70	107.41	96.80	56.15	66.17	75.32	80.05	82.07	83.47	91.41	99.54	102.84	102.19	73.87	95.34
Mars, at St James	78.05	107.52	106.89	102.37	92.91	53.27	62.79	71.39	75.72	77.56	78.83	86.05	93.57	96.50	97.55	69.93	89.67
Poseidon at St James	78.00	107.43	106.56	102.11	92.02	53.05	62.55	71.12	75.44	77.28	78.55	85.77	93.28	96.19	97.23	69.66	89.38
Western Hemisphere																	
Isthmus	78.91	109.48	107.93	106.46	94.91	55.66	65.38	74.14	78.56	80.39	81.62	88.90	96.52	99.47	99.54	72.62	92.57
Maya	71.29	99.87	100.89	98.55	87.12	48.24	57.22	65.26	69.15	70.86	72.04	78.83	85.93	88.65	91.54	63.80	82.24
Oriente	75.73	104.28	99.952	95.45	87.47	51.53	60.92	69.38	73.56	75.38	76.63	83.81	91.28	94.22	92.58	67.90	87.41
Castilla	73.07	101.89	104.52	99.82	89.20	46.97	55.90	63.86	67.68	69.35	70.50	77.25	84.34	87.06	93.70	62.38	80.65
Other Foreign																	
North Sea Dated	81.38	113.26	113.57	110.52	100.95	60.24	70.34	79.18	83.59	85.31	86.41	93.18	100.39	102.94	103.93	77.51	96.61
Bonny Light	84.43	116.32	116.72	114.30	104.21	64.06	74.46	83.76	88.44	90.25	91.40	98.25	105.70	108.36	107.19	82.06	101.82
Kissanje	82.09	113.42	112.98	110.78	100.40	59.41	69.74	78.58	82.97	84.75	85.87	92.95	100.30	102.89	103.93	76.89	96.41
Arab Light (FOB + Freight)	80.17	110.65	109.95	105.59	97.72	54.51	64.19	72.93	77.34	79.18	80.44	87.81	95.50	98.51	100.81	71.43	91.51
Arab Heavy (FOB + Freight)	77.03	106.33	105.97	101.55	93.89	49.49	58.72	67.09	71.27	73.13	74.43	81.68	89.15	92.10	96.95	65.69	85.27
Crude Relationships																	
FOB Relationships																	
LLS - Brent	3.25	1.05	0.12	-1.27	-2.19	-1.64	-1.56	-1.12	-0.73	-0.40	-0.08	1.21	2.26	3.08	0.19	-0.92	1.79
LLS-Mars	4.75	4.83	4.87	5.11	3.96	2.88	3.38	3.93	4.34	4.51	4.64	5.35	5.97	6.34	4.70	3.94	5.67
LLS-Maya at USGC	11.44	12.42	10.81	8.86	9.68	7.90	8.95	10.06	10.90	11.21	11.43	12.58	13.61	14.20	10.64	10.08	13.10

MUSE STANCIL

T A B L E A - 7

SINGAPORE PRODUCT PRICE FORECAST

(U.S. Currency in the Units as Noted)

		Historical (Nominal $)					*Projected (Real $)*									*Averages*		
	Units	***2010***	***2011***	***2012***	***2013***	***2014***	***2015***	***2016***	***2017***	***2018***	***2019***	***2020***	***2025***	***2030***	***2035***	***2010-14***	***2015-20***	***2021-35***
Key Parameters																		
Tapis FOB	$/B	82.65	117.11	117.01	115.18	102.97	60.38	71.16	80.69	85.45	87.28	88.46	95.59	103.28	105.98	106.98	78.90	99.25
Tapis at Singapore	$/B	83.45	118.09	118.02	116.15	103.95	61.07	71.92	81.52	86.31	88.15	89.33	96.52	104.25	106.98	107.93	79.72	100.20
Tapis 2-1-1 Crack	$/B	5.31	4.29	6.32	4.26	6.93	5.50	5.61	4.42	4.97	5.26	5.36	5.67	6.14	6.40	5.42	5.19	5.94
Light vs. Heavy Products	$/B	16.24	22.19	20.99	25.11	24.47	18.07	19.03	22.00	23.88	24.21	24.43	24.58	25.49	26.02	21.80	21.94	25.23
Diesel 50 ppm - Regular 92	¢/G	11.38	21.36	21.10	20.05	13.56	17.71	17.99	18.24	18.37	18.43	18.47	18.68	18.91	19.00	17.49	18.20	18.79
Refined Products																		
Unleaded Gasoline																		
Premium 97 (500 ppm)	¢/G	214.30	290.24	299.89	289.37	269.24	156.62	183.67	204.41	217.60	222.86	226.03	244.50	264.75	272.12	272.61	201.87	254.25
Regular 92 (500 ppm)	¢/G	205.65	280.71	285.49	276.66	257.24	149.64	175.59	195.49	208.14	213.20	216.24	233.96	253.39	260.46	261.15	193.05	243.32
Naphtha	¢/G	189.05	244.45	247.14	241.29	225.05	135.63	157.35	172.33	181.91	185.43	187.87	203.23	219.50	225.04	229.40	170.09	210.88
Jet fuel	¢/G	214.74	299.00	302.03	292.86	267.89	166.63	192.23	211.90	224.38	229.37	232.37	249.89	269.08	276.06	275.30	209.48	259.13
Distillate																		
Gasoil (50 S, 53 C)	¢/G	217.03	302.07	306.59	296.71	270.80	167.35	193.58	213.73	226.52	231.63	234.70	252.64	272.30	279.46	278.64	211.25	262.11
Gasoil (500 S, 49 C)	¢/G	214.90	300.31	304.36	293.83	269.12	165.68	191.80	211.88	224.61	229.70	232.76	250.63	270.21	277.34	276.51	209.41	260.06
Gas Oil (0.5%S, 48 C)	¢/G	213.08	296.30	300.46	289.34	266.51	162.67	188.63	208.59	221.24	226.30	229.34	247.11	266.57	273.65	273.14	206.13	256.48
Residual fuel																		
LSWR	$/B	73.17	109.81	115.50	106.27	98.64	53.18	63.59	69.74	73.65	75.57	76.70	84.23	91.87	94.48	100.68	68.74	87.73
HSFO 180 cSt 2.0%S	$/B	75.07	105.08	106.35	97.56	88.37	49.08	60.30	66.36	70.22	72.25	73.44	81.68	89.86	92.60	94.49	65.28	85.37
HSFO 180 cSt 3.5%S	$/B	72.52	100.20	103.35	95.30	86.41	48.50	58.50	63.93	67.40	69.20	70.27	77.61	84.91	87.36	91.56	62.97	80.91
HSFO 380 cSt 4.0%S	$/B	71.18	98.16	101.55	94.19	85.24	47.53	57.33	62.66	66.05	67.82	68.86	76.06	83.21	85.61	90.07	61.71	79.29
Singapore Relationships																		
Premium 97 - Regular 92	¢/G	8.65	9.53	14.40	12.71	12.00	6.98	8.08	8.92	9.45	9.66	9.79	10.54	11.36	11.66	11.46	8.81	10.94
Unleaded Reg - Naphtha	¢/G	16.60	36.26	38.35	35.37	32.19	14.01	18.24	23.16	26.24	27.77	28.37	30.73	33.89	35.41	31.75	22.96	32.44
Gas Oil 50 S - Reg Gasoline 92	¢/G	11.38	21.36	21.10	20.05	13.56	17.71	17.99	18.24	18.37	18.43	18.47	18.68	18.91	19.00	17.49	18.20	18.79
Gas Oil 50 vs 0.5%S	¢/G	3.95	5.77	6.13	7.37	4.29	4.68	4.95	5.15	5.28	5.33	5.36	5.54	5.73	5.80	5.50	5.12	5.63
Gas Oil 50 S vs 500 S	¢/G	2.13	1.76	2.22	2.87	1.67	1.67	1.77	1.85	1.91	1.93	1.94	2.01	2.09	2.12	2.13	1.85	2.05
Gas Oil 50 S - Jet	¢/G	2.29	3.07	4.55	3.84	2.91	0.73	1.35	1.83	2.13	2.26	2.33	2.76	3.22	3.39	3.33	1.77	2.98
LSWR - HSFO 180 3.5%S	$/B	0.65	9.62	12.16	10.98	12.22	4.68	5.09	5.81	6.26	6.36	6.43	6.62	6.97	7.13	9.12	5.77	6.83
2-1-1 Light/Heavy Products	$/B	15.41	20.98	19.70	23.56	23.57	17.09	17.99	20.92	22.78	23.09	23.30	23.41	24.28	24.81	20.64	20.86	24.05

MUSE STANCIL

TABLE A-8

SINGAPORE CRUDE PRICE FORECAST

(U.S. Dollars per Barrel)

	Historical (Nominal $)					*Projected (Real $)*								*Averages*		
	2010	***2011***	***2012***	***2013***	***2014***	***2015***	***2016***	***2017***	***2018***	***2019***	***2020***	***2025***	***2035***	***2010-14***	***2015-20***	***2021-35***
Reference Prices, FOB																
LLS at St James	82.73	112.28	111.70	107.41	96.80	56.15	66.17	75.32	80.05	82.07	83.47	91.41	102.84	102.19	73.87	95.34
North Sea Dated	79.49	111.23	111.58	108.68	98.99	57.78	67.72	76.44	80.78	82.47	83.55	90.20	99.76	101.99	74.79	93.55
Maya at Cayo	70.24	98.65	99.58	97.33	85.80	47.18	56.08	64.04	67.90	69.60	70.76	77.49	87.21	90.32	62.59	80.86
Dubai at Fateh	78.04	106.19	108.89	105.48	96.54	53.08	63.52	72.15	76.35	78.07	79.18	86.21	96.10	99.03	70.39	89.65
Arab Light (to Asia)	78.18	108.42	111.29	108.10	97.82	54.13	64.67	73.47	77.76	79.52	80.64	87.73	97.75	100.76	71.70	91.22
Arab Heavy (to Asia)	75.47	104.40	108.07	103.94	93.28	49.88	60.24	68.49	72.43	74.13	75.21	82.27	92.01	97.03	66.73	85.63
Tapis FOB	82.65	117.11	117.01	115.18	102.97	60.38	71.16	80.69	85.45	87.28	88.46	95.59	105.98	106.98	78.90	99.25
Prices at Singapore																
Tapis	83.45	118.09	118.02	116.15	103.95	61.07	71.92	81.52	86.31	88.15	89.33	96.52	106.98	107.93	79.72	100.20
Dubai	80.05	108.63	111.40	107.88	99.19	54.13	64.66	73.38	77.61	79.36	80.47	87.59	97.59	101.43	71.60	91.07
Arab Light	79.57	109.82	112.78	109.51	99.28	55.23	65.87	74.75	79.08	80.86	82.00	89.16	99.30	102.19	72.96	92.69
Arab Heavy	76.87	105.80	109.58	105.36	94.76	50.99	61.45	69.78	73.76	75.48	76.57	83.71	93.57	98.48	68.01	87.12
Minas	82.92	115.21	117.25	111.12	101.36	57.24	68.10	77.16	81.61	83.44	84.60	91.91	102.27	105.57	75.36	95.52
Duri	77.40	108.40	113.72	106.95	98.63	49.99	60.54	68.72	72.62	74.35	75.44	82.68	87.97	101.02	66.94	85.01
Northwest Shelf Condensate	80.05	109.63	107.55	106.22	97.95	59.90	70.32	79.90	84.68	86.40	87.55	94.38	104.47	100.28	78.12	97.96
Crude Relationships																
FOB Differentials																
Dated - Dubai Fateh	1.45	5.04	2.69	3.20	2.45	4.71	4.21	4.29	4.43	4.40	4.37	3.98	3.66	2.97	4.40	3.90
Tapis - Dubai	4.61	10.91	8.12	9.70	6.43	7.31	7.64	8.54	9.10	9.21	9.28	9.38	9.88	7.96	8.51	9.59
Tapis - LLS	-0.08	4.82	5.32	7.77	6.17	4.24	4.99	5.37	5.40	5.21	4.99	4.19	3.14	4.80	5.03	3.91
Tapis - Dated	3.16	5.87	5.43	6.50	3.98	2.60	3.43	4.25	4.67	4.81	4.91	5.40	6.22	4.99	4.11	5.70
Arab Lt - Dubai	0.15	2.23	2.40	2.62	1.28	1.05	1.16	1.31	1.41	1.45	1.46	1.52	1.64	1.73	1.31	1.57
Arab Hvy - Maya	5.23	5.75	8.49	6.60	7.48	2.70	4.17	4.44	4.53	4.53	4.45	4.78	4.79	6.71	4.14	4.77
At Singapore																
Tapis vs Tapis FOB	0.80	0.98	1.01	0.96	0.98	0.69	0.76	0.83	0.86	0.87	0.88	0.93	1.00	0.95	0.81	0.95
Tapis - Dubai	3.40	9.46	6.62	8.27	4.76	6.94	7.26	8.14	8.69	8.79	8.86	8.93	9.39	6.50	8.11	9.13
Tapis - Duri	6.05	9.69	4.30	9.20	5.32	11.08	11.38	12.80	13.69	13.80	13.89	13.83	19.01	6.91	12.77	15.19
Tapis - Arab Lt	3.89	8.27	5.24	6.64	4.68	5.85	6.05	6.77	7.22	7.29	7.34	7.35	7.68	5.74	6.75	7.51
Tapis - Arab Hvy	6.58	12.28	8.44	10.78	9.20	10.08	10.47	11.74	12.55	12.67	12.76	12.81	13.41	9.46	11.71	13.08

T A B L E A - 9

TRANSPORTATION SUMMARY ANALYSIS

TRANS MOUNTAIN EXPANSION SCENARIO

(Thousands of Barrels per Day, Unless Noted)

Year	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*	*2031*	*2032*	*2033*	*2034*	*2035*	*2036*	*2037*	*2038*
Trans Mountain																					
Light	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0
Heavy	540.0	540.0	540.0	540.0	540.0	540.0	540.0	540.0	540.0	540.0	540.0	540.0	540.0	540.0	540.0	540.0	540.0	540.0	540.0	540.0	540.0
Total	**840.0**	**840.0**	**840.0**	**840.0**	**840.0**	**840.0**	**840.0**	**840.0**	**840.0**	**840.0**	**840.0**	**840.0**	**840.0**	**840.0**	**840.0**	**840.0**	**840.0**	**840.0**	**840.0**	**840.0**	**840.0**
Total Other Pipelines from Western Canada																					
Light[1]	803.4	826.7	804.6	802.7	768.9	775.5	761.5	736.8	761.1	772.8	760.7	806.1	801.8	826.9	829.3	799.6	777.2	756.4	756.8	790.1	812.5
Heavy	2,941.2	2,960.8	2,995.3	3,035.4	3,047.3	3,039.2	3,125.4	3,149.7	3,155.0	3,152.1	3,150.6	3,154.0	3,152.6	3,159.7	3,159.5	3,155.0	3,143.4	3,131.9	3,130.0	3,125.7	3,126.7
Total	**3,744.6**	**3,787.4**	**3,799.9**	**3,838.1**	**3,816.2**	**3,814.6**	**3,886.9**	**3,886.5**	**3,916.0**	**3,924.9**	**3,911.4**	**3,960.1**	**3,954.4**	**3,986.6**	**3,988.9**	**3,954.6**	**3,920.6**	**3,888.3**	**3,886.9**	**3,915.8**	**3,939.3**
Total Rail from Western Canada																					
Light	25.0	50.0	75.0	100.0	125.0	150.0	185.1	305.5	295.8	266.5	393.7	357.8	416.1	429.3	466.5	575.4	672.9	744.1	763.0	758.4	761.0
Heavy	0.8	-	22.8	39.5	39.5	39.5	50.8	68.7	139.7	251.8	312.0	404.6	480.4	562.1	652.9	711.9	785.5	887.0	941.5	990.0	1,037.8
Total	**25.8**	**50.0**	**97.8**	**139.5**	**164.5**	**189.5**	**235.9**	**374.2**	**435.6**	**518.3**	**705.7**	**762.4**	**896.4**	**991.4**	**1,119.4**	**1,287.3**	**1,458.3**	**1,631.0**	**1,704.5**	**1,748.4**	**1,798.8**
Total Shipments																					
Light	1,128.4	1,176.7	1,179.6	1,202.7	1,193.9	1,225.5	1,246.6	1,342.4	1,356.9	1,339.3	1,454.4	1,463.9	1,517.8	1,556.2	1,595.9	1,675.0	1,750.1	1,800.5	1,819.9	1,848.5	1,873.5
Heavy	3,482.0	3,500.8	3,558.1	3,614.9	3,626.8	3,618.7	3,716.1	3,758.3	3,834.7	3,943.9	4,002.6	4,098.6	4,173.0	4,261.8	4,352.4	4,406.9	4,468.8	4,558.8	4,611.5	4,655.7	4,704.5
Total	**4,610.4**	**4,677.4**	**4,737.7**	**4,817.6**	**4,820.7**	**4,844.1**	**4,962.8**	**5,100.7**	**5,191.6**	**5,283.2**	**5,457.1**	**5,562.5**	**5,690.8**	**5,817.9**	**5,948.3**	**6,081.9**	**6,218.9**	**6,359.4**	**6,431.3**	**6,504.2**	**6,578.0**

Note: 1) Volume includes U.S. Bakken crude oil reciepts at Regina and Cromer.

T A B L E A - 10

DISPOSITION OF WESTERN CANADIAN SYNTHETIC AND LIGHT/MEDIUM CONVENTIONAL

TRANS MOUNTAIN EXPANSION SCENARIO

(Thousands of Barrels per Day, Unless Noted)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Sweet Synthetic																					
Western Canada	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2
Ontario/Quebec	93.7	87.7	87.7	87.7	105.3	105.3	99.2	106.0	100.0	100.0	106.0	117.6	117.6	117.6	117.6	106.0	106.0	106.0	106.0	106.0	106.0
Atlantic Canada	-	15.3	37.4	43.2	43.2	43.2	104.4	104.4	98.8	102.8	111.2	112.1	111.1	112.1	112.1	112.1	121.6	127.3	133.8	130.7	138.0
U.S. East Coast	5.9	16.8	16.8	16.8	16.8	16.8	16.8	16.8	22.4	25.1	16.8	30.3	81.1	111.0	114.6	124.1	131.3	131.3	131.3	131.3	131.3
Rockies	48.4	48.4	52.5	56.6	56.6	56.6	57.7	57.7	57.7	64.6	72.7	72.7	72.7	72.7	72.7	72.7	72.7	72.7	73.5	72.7	72.7
Upper Midwest	152.8	145.6	152.8	152.8	152.8	156.8	153.5	143.1	143.1	154.2	160.0	160.0	153.1	152.8	154.8	175.1	172.8	170.6	172.8	172.6	164.2
Lower Midwest	55.8	55.8	55.8	55.8	69.8	70.8	55.8	58.4	58.4	55.8	55.8	55.8	56.2	57.7	57.7	73.5	71.6	70.8	73.5	73.5	73.5
Mid-Continent	49.9	49.9	49.9	31.4	49.6	39.3	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7
Puget Sound/Burnaby	27.6	27.6	50.4	50.4	50.4	50.4	50.4	33.8	45.3	50.4	50.4	50.4	50.4	50.4	62.6	62.6	62.6	62.6	62.6	62.6	62.6
California/Hawaii	-	-	-	-	-	-	-	-	-	7.8	20.9	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5
U.S. Gulf Coast	202.3	209.4	205.0	203.9	161.6	142.1	102.2	50.5	48.6	50.6	69.3	98.6	112.5	125.5	176.6	190.0	222.0	252.6	257.6	279.1	295.1
Europe	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northeast Asia	101.4	92.3	75.9	98.5	95.5	106.2	110.4	160.4	140.4	95.5	148.1	107.3	81.6	66.2	28.0	12.1	-	-	-	-	2.7
India	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**917.9**	**928.8**	**964.3**	**977.1**	**981.6**	**967.6**	**951.3**	**932.0**	**915.5**	**907.6**	**1,012.0**	**1,038.3**	**1,069.5**	**1,099.4**	**1,130.1**	**1,161.6**	**1,194.0**	**1,227.3**	**1,244.5**	**1,261.8**	**1,279.4**
Canadian Light Sweet/Medium Sour																					
Western Canada	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1
Ontario/Quebec	115.6	113.4	110.0	106.8	95.8	88.1	97.4	59.2	59.2	59.2	59.2	59.2	59.2	59.2	59.2	59.2	59.2	59.2	59.2	59.2	59.2
Atlantic Canada	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. East Coast	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rockies	48.3	45.8	46.0	58.5	58.9	59.2	87.0	93.3	117.5	122.4	102.2	147.6	143.3	168.4	170.8	141.1	118.7	97.9	97.5	131.6	154.0
Upper Midwest	185.2	171.2	165.2	164.6	171.4	171.5	100.7	98.6	81.6	80.2	57.4	57.4	54.6	54.6	53.9	52.5	53.4	54.2	53.4	53.0	54.4
Lower Midwest	27.3	25.3	25.3	4.1	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Continent	37.0	21.3	18.2	34.2	15.5	15.5	23.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Puget Sound/Burnaby	164.0	164.0	141.3	141.3	141.3	138.7	139.2	153.4	139.5	135.8	182.8	150.1	153.7	159.6	151.6	166.1	191.2	214.8	217.9	186.0	163.9
California/Hawaii	32.0	66.1	107.5	109.9	137.8	154.8	185.1	232.5	243.9	250.2	252.9	247.7	254.8	229.6	241.9	264.4	266.7	269.2	270.4	271.6	272.8
U.S. Gulf Coast	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Europe	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northeast Asia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
India	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**721.5**	**719.3**	**725.6**	**731.5**	**735.7**	**739.9**	**744.8**	**749.1**	**753.8**	**759.9**	**766.6**	**774.1**	**777.7**	**783.5**	**789.4**	**795.3**	**801.3**	**807.3**	**810.4**	**813.4**	**816.5**

T A B L E A - 11

DISPOSITION OF WESTERN CANADIAN SYNTHETIC AND LIGHT/MEDIUM CONVENTIONAL

BASE SCENARIO

(Thousands of Barrels per Day, Unless Noted)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Sweet Synthetic																					
Western Canada	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2	180.2
Ontario/Quebec	106.0	106.0	106.0	106.0	106.0	106.0	100.0	106.0	100.0	100.0	100.0	106.0	103.1	117.6	106.0	106.0	106.0	106.0	106.0	106.0	106.0
Atlantic Canada	26.5	43.2	53.0	50.9	61.7	82.2	147.6	147.7	132.7	128.2	147.7	147.7	147.7	116.7	140.7	126.7	112.1	126.8	133.8	130.7	138.0
U.S. East Coast	33.5	16.8	16.8	16.8	34.1	16.8	48.9	16.8	18.4	20.6	76.4	102.0	109.0	109.0	109.0	114.6	114.6	114.6	123.8	128.3	122.8
Rockies	72.7	72.7	72.7	72.7	72.7	72.7	72.7	72.7	72.7	72.7	72.7	72.7	72.7	72.7	72.7	72.7	72.7	72.7	72.7	72.7	72.7
Upper Midwest	174.4	189.9	195.2	191.7	185.5	179.4	151.5	152.9	144.2	154.2	154.6	161.9	147.0	143.0	150.3	165.9	170.7	168.8	168.8	162.2	162.2
Lower Midwest	77.9	77.9	77.9	60.6	57.0	55.8	56.5	57.2	59.4	55.8	56.0	59.6	60.0	60.0	60.0	71.8	71.8	70.8	71.8	70.8	70.8
Mid-Continent	36.8	20.7	20.7	20.7	20.7	20.7	12.8	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7
Puget Sound/Burnaby	56.7	56.7	56.7	61.9	62.6	62.6	62.6	62.1	50.4	50.4	50.4	50.4	50.4	56.3	53.0	62.6	62.6	62.6	62.6	62.6	62.6
California/Hawaii	-	16.3	32.5	32.5	32.5	32.5	32.5	29.1	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5
U.S. Gulf Coast	116.5	86.7	77.2	83.2	89.0	102.8	74.0	86.6	104.4	92.5	120.8	104.6	146.2	190.7	205.0	207.9	250.1	271.6	271.6	295.2	310.9
Europe	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northeast Asia	36.9	61.9	75.5	100.0	79.6	56.0	12.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
India	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**917.9**	**928.8**	**964.3**	**977.1**	**981.6**	**967.6**	**951.3**	**932.0**	**915.5**	**907.6**	**1,012.0**	**1,038.3**	**1,069.5**	**1,099.4**	**1,130.1**	**1,161.6**	**1,194.0**	**1,227.3**	**1,244.5**	**1,261.8**	**1,279.4**
Canadian Light Sweet/Medium Sour																					
Western Canada	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1	112.1
Ontario/Quebec	97.0	92.8	90.7	78.6	58.9	59.2	59.2	59.2	59.2	59.2	59.2	59.2	59.2	59.2	59.2	59.2	59.2	59.2	59.2	59.2	59.2
Atlantic Canada	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. East Coast	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rockies	113.0	115.5	116.5	121.6	125.0	155.1	180.4	184.8	164.9	123.0	118.4	142.9	153.4	179.1	164.9	169.5	172.6	167.9	171.6	179.8	200.7
Upper Midwest	147.6	143.6	125.5	86.6	83.5	76.9	65.0	62.0	59.8	62.3	59.8	56.2	54.6	54.6	52.1	56.9	51.9	55.1	48.1	48.1	52.3
Lower Midwest	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Continent	11.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Puget Sound/Burnaby	102.9	107.7	129.1	149.0	156.7	151.5	148.6	149.8	173.1	203.4	214.9	221.6	227.1	194.9	227.0	198.0	203.4	208.5	213.7	182.3	159.0
California/Hawaii	136.6	147.7	151.8	183.6	199.4	185.1	179.5	181.2	184.8	199.8	202.1	182.1	171.3	183.6	174.1	199.7	202.1	204.6	205.8	232.0	233.2
U.S. Gulf Coast	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Europe	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northeast Asia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
India	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**721.5**	**719.3**	**725.6**	**731.5**	**735.7**	**739.9**	**744.8**	**749.1**	**753.8**	**759.9**	**766.6**	**774.1**	**777.7**	**783.5**	**789.4**	**795.3**	**801.3**	**807.3**	**810.4**	**813.4**	**816.5**

T A B L E A - 12

DISPOSITION OF CANADIAN HEAVY

TRANS MOUNTAIN EXPANSION SCENARIO

(Thousands of Barrels per Day, Unless Noted)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Conventional Heavy (LLB)																					
Western Canada	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3
Ontario/Quebec	41.5	45.9	45.9	45.9	45.9	45.9	45.9	34.4	34.4	34.4	34.4	34.4	33.5	33.5	33.5	33.5	33.5	33.5	33.5	33.5	33.5
Atlantic Canada	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. East Coast	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rockies	112.0	112.3	125.1	129.2	119.3	85.4	52.1	44.6	35.7	32.0	36.7	32.4	32.0	38.8	38.6	33.4	32.0	32.0	30.4	25.7	26.9
Upper Midwest	98.7	86.1	92.4	92.2	88.1	112.6	101.6	134.0	131.7	131.0	124.0	120.9	114.0	102.1	98.1	111.1	109.9	115.6	107.2	102.8	89.6
Lower Midwest	74.2	73.1	40.6	21.2	21.2	21.2	58.8	39.7	45.5	45.5	44.2	48.7	54.7	56.1	56.8	45.5	44.8	35.7	44.0	51.5	61.8
Mid-Continent	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Puget Sound	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. Gulf Coast	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Europe	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northeast Asia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
India	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**349.6**	**340.7**	**327.4**	**311.8**	**297.8**	**288.3**	**281.7**	**276.0**	**270.6**	**266.2**	**262.6**	**259.7**	**257.4**	**253.8**	**250.3**	**246.9**	**243.5**	**240.1**	**238.4**	**236.8**	**235.1**
Western Canadian Select																					
Western Canada	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ontario/Quebec	12.9	8.1	8.1	8.1	8.1	-	-	-	-	-	-	-	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Atlantic Canada	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. East Coast	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rockies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Upper Midwest	269.4	279.5	270.4	266.6	267.4	208.5	236.3	195.9	222.0	222.0	222.1	235.4	254.0	266.6	276.2	279.8	283.4	269.4	278.9	284.4	301.6
Lower Midwest	-	1.7	-	1.7	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Continent	43.1	41.2	36.8	43.2	20.8	19.9	10.1	4.6	4.7	4.7	4.6	4.1	3.8	0.1	4.1	0.1	4.1	4.7	4.4	4.1	4.7
Puget Sound	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. Gulf Coast	49.7	44.6	59.8	55.5	77.0	146.6	128.6	174.5	148.3	148.3	148.3	135.6	116.2	107.3	93.8	94.2	86.6	100.0	90.7	85.5	67.7
Europe	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northeast Asia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
India	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**
Cold Lake Blend																					
Western Canada	100.2	100.2	100.2	100.2	100.2	134.8	134.8	134.8	134.8	134.8	134.8	134.8	134.8	134.8	134.8	134.8	134.8	134.8	134.8	134.8	134.8
Ontario/Quebec	63.2	63.2	63.2	63.2	63.2	63.2	63.2	70.4	70.4	70.4	70.4	70.4	70.4	70.4	70.4	70.4	70.4	70.4	70.4	70.4	70.4
Atlantic Canada	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. East Coast	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rockies	16.0	16.0	16.0	16.5	16.5	16.5	14.0	14.0	27.1	27.4	20.9	28.1	26.8	28.1	28.1	28.1	15.7	4.2	4.0	4.0	4.0
Upper Midwest	69.7	80.8	84.7	97.3	98.8	86.5	97.8	95.0	87.3	85.2	90.3	86.7	91.5	96.3	96.7	96.0	96.1	95.6	96.3	99.5	109.9
Lower Midwest	29.7	29.5	67.2	91.8	92.2	84.6	54.2	55.9	49.5	49.5	50.9	47.9	43.8	37.6	37.3	49.5	50.3	62.3	55.6	52.5	42.0
Mid-Continent	19.5	19.5	23.3	29.5	25.1	22.3	22.3	16.2	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	22.3	22.3	22.3
Puget Sound	11.0	8.1	6.7	6.7	6.6	6.6	6.6	6.6	7.7	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. Gulf Coast	49.7	148.3	148.3	148.3	190.7	177.7	212.6	212.6	212.6	212.6	212.6	212.0	212.6	212.6	212.6	201.2	212.6	212.6	212.6	212.6	212.6
Europe	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northeast Asia	223.0	128.1	96.0	52.1	12.2	13.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
India	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**582.1**	**593.7**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**

T A B L E A - 12

DISPOSITION OF CANADIAN HEAVY

TRANS MOUNTAIN EXPANSION SCENARIO

(Thousands of Barrels per Day, Unless Noted)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Athabasca SynBit																					
Western Canada	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ontario/Quebec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Atlantic Canada	-	-	-	-	-	-	-	-	-	8.6	8.6	7.6	13.4	13.4	13.4	0.2	13.4	13.4	13.4	13.4	15.3
U.S. East Coast	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rockies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Upper Midwest	-	-	-	-	0.4	15.4	16.1	17.4	40.8	40.9	41.6	41.1	42.1	43.0	42.9	43.3	43.3	43.5	43.2	43.1	42.6
Lower Midwest	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Continent	-	-	-	-	-	-	-	3.4	3.4	3.4	3.4	4.0	4.2	8.0	4.0	8.0	4.0	3.4	3.7	4.0	3.4
Puget Sound	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. Gulf Coast	68.2	82.5	80.5	85.2	94.7	106.2	144.1	193.8	210.3	217.3	216.4	270.8	320.3	322.7	326.3	331.6	338.7	348.0	372.8	401.2	433.6
Europe	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northeast Asia	163.0	163.1	133.0	140.8	156.1	160.1	222.1	299.4	303.4	306.1	304.1	394.8	469.7	468.9	479.0	496.4	499.1	514.9	555.8	602.5	655.2
India	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**231.2**	**245.7**	**213.6**	**226.0**	**251.2**	**281.7**	**382.3**	**514.0**	**557.8**	**576.3**	**574.1**	**718.3**	**849.7**	**855.9**	**865.6**	**879.5**	**898.4**	**923.1**	**988.9**	**1,064.1**	**1,150.1**
Athabasca DilBit																					
Western Canada	102.1	102.1	102.1	102.1	102.1	136.7	136.7	136.7	136.7	136.7	136.7	136.7	136.7	136.7	136.7	136.7	136.7	136.7	136.7	136.7	136.7
Ontario/Quebec	16.0	15.5	16.3	22.1	22.1	30.1	30.1	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7
Atlantic Canada	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. East Coast	21.9	21.9	43.9	54.8	54.8	54.8	66.1	77.4	77.4	77.4	77.4	77.4	77.4	77.4	77.4	77.4	77.4	77.4	77.4	77.4	77.4
Rockies	10.1	9.8	8.3	9.4	15.8	19.6	25.2	26.1	27.2	27.7	28.0	28.5	28.9	27.8	27.8	28.4	30.7	30.7	30.6	31.1	30.9
Upper Midwest	455.4	448.1	446.8	442.6	441.4	471.8	464.5	468.1	445.7	449.7	446.3	441.5	425.7	419.2	414.1	407.7	404.3	406.3	405.5	401.8	390.2
Lower Midwest	94.6	94.6	90.9	87.5	89.4	94.6	97.9	103.3	104.0	103.7	103.5	102.0	100.2	105.1	104.8	105.7	105.4	102.4	101.1	96.7	96.8
Mid-Continent	57.9	59.3	61.9	61.4	78.5	88.6	95.7	93.4	96.7	90.1	89.4	91.9	93.1	91.5	93.1	95.4	93.1	93.1	94.6	94.6	94.6
Puget Sound	21.9	21.9	23.3	23.3	23.3	25.9	25.4	27.8	30.2	30.7	28.4	29.7	29.7	29.9	31.1	30.5	32.3	29.5	31.4	29.5	25.8
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. Gulf Coast	488.4	497.7	502.0	530.7	549.8	556.9	617.4	686.5	701.4	690.7	687.5	606.4	573.3	579.6	585.5	627.2	637.7	684.1	674.9	671.1	674.9
Europe	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northeast Asia	121.2	218.8	280.9	317.2	341.7	334.0	285.9	212.8	276.4	368.1	432.5	433.2	434.1	516.4	595.9	638.1	707.2	738.3	727.5	712.5	684.8
India	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**1,389.4**	**1,489.7**	**1,576.5**	**1,651.0**	**1,718.9**	**1,813.3**	**1,844.9**	**1,865.8**	**1,929.4**	**2,008.5**	**2,063.5**	**1,981.1**	**1,932.7**	**2,017.2**	**2,100.1**	**2,180.7**	**2,258.4**	**2,332.2**	**2,313.3**	**2,285.0**	**2,245.9**
Sour Synthetic																					
Western Canada	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2
Ontario/Quebec	33.3	33.8	33.9	33.8	33.3	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2
Atlantic Canada	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. East Coast	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rockies	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8
Upper Midwest	8.2	10.1	12.5	15.1	17.8	14.9	20.8	19.7	24.9	21.5	27.5	31.7	44.4	48.7	53.4	58.4	61.6	61.6	61.6	63.9	71.9
Lower Midwest	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Continent	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Puget Sound	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. Gulf Coast	-	-	-	-	-	2.2	0.7	7.9	3.4	7.0	14.6	23.3	23.3	23.3	23.3	23.3	25.5	31.5	38.1	43.0	43.0
Northeast Asia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
India	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**129.5**	**131.9**	**134.5**	**137.0**	**139.2**	**139.4**	**143.8**	**149.9**	**150.6**	**150.8**	**164.3**	**177.2**	**189.9**	**194.3**	**198.9**	**204.0**	**209.4**	**215.4**	**222.0**	**229.2**	**237.1**

T A B L E A - 13

DISPOSITION OF CANADIAN HEAVY

BASE SCENARIO

(Thousands of Barrels per Day, Unless Noted)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Conventional Heavy (LLB)																					
Western Canada	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3
Ontario/Quebec	38.0	38.0	38.0	36.6	33.5	34.4	34.4	34.4	34.4	34.4	33.5	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2	26.2
Atlantic Canada	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. East Coast	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rockies	122.8	115.8	115.4	108.5	104.2	70.3	34.9	32.0	33.4	32.0	32.0	32.4	32.0	43.5	60.4	55.2	42.0	28.9	22.5	17.7	18.8
Upper Midwest	121.9	130.9	124.6	112.2	90.8	107.2	153.4	165.1	179.5	176.5	173.8	177.9	176.0	161.0	140.5	142.3	152.0	161.7	166.5	169.7	166.9
Lower Midwest	43.7	32.7	26.2	31.2	45.9	53.2	35.6	21.2	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Continent	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Puget Sound	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. Gulf Coast	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Europe	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northeast Asia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
India	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**349.6**	**340.7**	**327.4**	**311.8**	**297.8**	**288.3**	**281.7**	**276.0**	**270.6**	**266.2**	**262.6**	**259.7**	**257.4**	**253.8**	**250.3**	**246.9**	**243.5**	**240.1**	**238.4**	**236.8**	**235.1**
Western Canadian Select																					
Western Canada	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ontario/Quebec	-	-	-	-	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Atlantic Canada	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. East Coast	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rockies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Upper Midwest	154.4	159.2	171.0	191.3	219.0	222.1	171.0	141.1	144.6	123.4	130.3	137.5	152.4	170.5	196.2	172.8	184.1	157.2	159.4	170.5	160.0
Lower Midwest	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Continent	4.0	2.6	7.7	10.8	5.5	4.6	4.6	-	-	-	-	-	-	-	-	-	-	-	-	1.7	2.8
Puget Sound	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. Gulf Coast	216.6	213.2	196.3	172.9	149.6	148.3	199.3	233.9	230.4	251.6	244.7	237.5	222.6	204.5	178.8	202.2	190.9	217.8	215.6	202.8	212.2
Europe	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northeast Asia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
India	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**	**375.0**
Cold Lake Blend																					
Western Canada	100.2	100.2	100.2	100.2	100.2	134.8	134.8	134.8	134.8	134.8	134.8	134.8	134.8	134.8	134.8	134.8	134.8	134.8	134.8	134.8	134.8
Ontario/Quebec	70.4	70.4	70.4	70.4	70.4	70.4	70.4	70.4	70.4	70.4	71.3	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0
Atlantic Canada	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. East Coast	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.3
Rockies	24.2	27.9	26.2	28.0	28.3	28.1	28.1	23.1	28.1	28.1	25.6	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1
Upper Midwest	113.1	106.4	111.7	117.9	113.3	101.9	85.9	91.6	101.2	107.5	118.0	126.7	130.2	133.3	137.0	164.2	140.4	155.8	156.1	150.9	170.2
Lower Midwest	38.8	53.5	61.8	53.6	53.7	49.5	63.2	78.6	102.4	100.2	100.4	100.2	113.0	113.0	113.0	113.3	142.5	130.5	141.6	141.3	150.2
Mid-Continent	16.1	16.1	16.1	16.2	17.6	16.2	16.2	16.2	16.2	16.2	16.2	19.9	22.4	22.4	24.1	24.1	30.6	28.7	31.6	30.6	29.3
Puget Sound	6.6	6.6	6.6	6.6	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.7	9.5
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. Gulf Coast	212.6	212.6	212.6	212.6	212.6	195.2	197.4	181.4	142.8	138.8	129.7	107.3	88.4	85.3	79.9	52.4	40.6	39.0	24.8	31.1	-
Europe	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northeast Asia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
India	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**582.1**	**593.7**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**

T A B L E A - 13

DISPOSITION OF CANADIAN HEAVY

BASE CASE (NO NORTHERN GATEWAY)

(Thousands of Barrels per Day, Unless Noted)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Conventional Heavy																		
Western Canada	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Ontario/Quebec	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Rockies	3.5	15.2	12.0	17.5	17.5	30.6	25.8	26.1	29.1	28.9	26.4	27.1	16.6	16.6	16.6	16.6	16.6	17.2
Upper Midwest	162.9	142.7	139.0	120.6	126.5	124.5	122.7	103.4	96.1	93.2	87.2	78.1	80.8	73.5	66.7	60.3	54.3	48.2
Lower Midwest	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Continent	2.9	8.7	8.7	8.7	8.7	6.6	-	-	-	-	-	-	-	-	-	-	-	-
Puget Sound	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. Gulf Coast	64.3	53.3	46.2	47.5	29.5	6.9	6.3	13.6	7.6	0.5	-	-	-	-	-	-	-	-
Northeast Asia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**246.4**	**232.7**	**218.7**	**207.1**	**195.0**	**181.4**	**167.5**	**155.8**	**145.5**	**135.9**	**127.0**	**118.6**	**110.8**	**103.5**	**96.6**	**90.2**	**84.3**	**78.7**
Western Canadian Select																		
Western Canada	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ontario/Quebec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rockies	-	20.2	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	29.2	30.7	31.1	30.2	33.8	35.4	35.4
Upper Midwest	15.9	15.7	21.8	15.6	15.6	23.9	24.5	15.6	15.6	15.6	15.6	19.9	35.4	37.6	46.3	55.8	61.9	75.6
Lower Midwest	108.9	87.3	20.1	26.3	21.2	35.6	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	0.0	0.0	0.0
Mid-Continent	-	-	-	-	-	-	-	-	-	-	-	-	-	2.7	8.4	8.4	8.4	8.4
Puget Sound	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. Gulf Coast	370.2	371.8	425.1	425.1	430.2	407.6	436.7	445.6	445.6	445.6	445.6	440.1	423.2	417.8	404.3	396.9	389.3	375.5
Northeast Asia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**495.0**	**495.0**	**495.0**	**495.0**	**495.0**	**495.0**	**495.0**	**495.0**	**495.0**	**495.0**	**495.0**	**495.0**	**495.0**	**495.0**	**495.0**	**495.0**	**495.0**	**495.0**
Cold Lake Blend																		
Western Canada	83.7	83.7	83.7	83.7	83.7	83.7	83.7	83.7	83.7	83.7	83.7	83.7	83.7	83.7	83.7	83.7	83.7	83.7
Ontario/Quebec	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2	63.7	50.5	50.5	50.5	50.5	50.5
Rockies	97.9	107.6	119.4	115.5	115.7	109.2	115.0	115.1	115.7	116.9	118.3	117.9	127.6	127.6	127.6	127.2	128.1	127.4
Upper Midwest	263.1	191.4	151.9	156.9	146.8	171.0	172.9	200.0	181.1	185.0	191.3	198.0	177.6	166.7	154.8	125.4	126.0	122.4
Lower Midwest	-	-	-	9.4	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
Mid-Continent	42.1	48.0	48.0	48.0	48.0	56.1	62.7	61.8	64.1	56.7	56.7	56.7	54.2	53.0	53.0	26.5	26.5	27.7
Puget Sound	2.0	2.0	2.0	2.0	2.0	2.0	2.0	1.6	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. Gulf Coast	-	14.7	1.1	42.6	4.2	-	-	-	9.3	-	-	-	-	-	3.1	48.4	52.7	52.7
Northeast Asia	28.1	81.1	134.2	82.2	121.2	99.7	85.3	59.5	67.7	79.3	71.6	65.3	80.0	105.4	114.3	125.3	119.5	122.6
Total	**582.1**	**593.7**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**	**605.6**

TABLE A-13

DISPOSITION OF CANADIAN HEAVY

BASE SCENARIO

(Thousands of Barrels per Day, Unless Noted)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Athabasca SynBit																					
Western Canada	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ontario/Quebec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Atlantic Canada	-	13.8	15.3	15.3	15.3	15.3	15.3	17.1	15.3	15.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3
U.S. East Coast	26.3	22.5	16.9	20.5	5.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rockies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Upper Midwest	67.7	67.7	54.0	54.5	54.5	51.0	44.8	55.0	54.9	54.9	54.9	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0
Lower Midwest	41.0	31.2	27.5	30.6	15.8	-	-	3.2	-	-	-	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Mid-Continent	27.9	27.9	8.0	8.0	8.0	3.4	3.4	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	6.3	5.2
Puget Sound	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.3	3.8
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. Gulf Coast	68.2	82.5	80.5	85.2	94.7	106.2	144.1	193.8	210.3	217.3	216.4	270.8	320.3	322.7	326.3	331.6	338.7	348.0	372.8	401.2	433.6
Europe	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northeast Asia	-	-	11.3	11.9	57.2	105.9	174.7	236.9	269.3	280.9	272.6	359.9	441.7	445.6	451.7	460.3	472.1	487.5	528.5	573.8	627.9
India	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**231.2**	**245.7**	**213.6**	**226.0**	**251.2**	**281.7**	**382.3**	**514.0**	**557.8**	**576.3**	**574.1**	**718.3**	**849.7**	**855.9**	**865.6**	**879.5**	**898.4**	**923.1**	**988.9**	**1,064.1**	**1,150.1**
Athabasca DilBit																					
Western Canada	102.1	102.1	102.1	102.1	102.1	136.7	136.7	136.7	136.7	136.7	136.7	136.7	136.7	136.7	136.7	136.7	136.7	136.7	136.7	136.7	136.7
Ontario/Quebec	30.1	30.1	30.1	31.5	33.7	33.7	33.7	33.7	33.7	33.7	33.6	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3
Atlantic Canada	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. East Coast	32.9	54.8	60.5	56.9	71.7	77.4	77.4	77.4	77.4	77.4	77.4	77.4	77.4	77.4	77.4	77.4	77.4	77.4	77.4	77.4	77.4
Rockies	17.5	18.4	18.5	19.4	19.9	24.0	28.2	29.7	28.4	28.5	28.6	28.5	28.5	26.8	24.1	24.7	26.3	27.9	28.6	29.2	29.1
Upper Midwest	449.3	449.4	455.7	451.4	447.8	450.1	464.4	466.7	447.5	462.1	449.8	434.1	419.2	413.0	406.6	402.7	410.4	409.0	402.3	393.9	386.8
Lower Midwest	78.5	84.7	86.7	84.7	84.3	96.0	99.9	96.7	96.6	98.5	98.3	97.5	92.9	93.3	92.7	94.6	85.0	86.3	81.3	79.5	76.9
Mid-Continent	74.2	73.5	86.5	83.4	90.8	92.2	90.0	91.8	93.2	93.0	92.9	95.9	99.1	97.7	97.2	98.2	94.1	94.0	92.3	92.9	93.7
Puget Sound	11.7	11.7	20.4	23.6	30.0	30.2	30.3	36.1	36.5	37.7	37.5	36.8	36.1	38.8	36.3	39.9	39.7	39.4	39.2	40.8	40.4
California	-	-	-	-	-	10.5	17.8	12.0	11.7	10.5	10.7	11.4	38.2	29.3	45.2	17.7	15.7	27.6	41.4	55.1	57.1
U.S. Gulf Coast	593.0	664.9	716.1	797.9	838.6	862.5	866.4	885.0	950.2	974.5	983.9	952.5	926.2	979.6	1,015.3	1,079.0	1,125.0	1,151.2	1,147.4	1,133.1	1,130.5
Europe	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Northeast Asia	-	-	-	-	-	-	-	-	17.5	56.0	114.3	77.0	45.1	91.2	135.2	176.5	214.8	249.4	233.4	213.1	184.0
India	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**1,389.4**	**1,489.7**	**1,576.5**	**1,651.0**	**1,718.9**	**1,813.3**	**1,844.9**	**1,865.8**	**1,929.4**	**2,008.5**	**2,063.5**	**1,981.1**	**1,932.7**	**2,017.2**	**2,100.1**	**2,180.7**	**2,258.4**	**2,332.2**	**2,313.3**	**2,285.0**	**2,245.9**
Sour Synthetic																					
Western Canada	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2
Ontario/Quebec	33.5	34.0	34.6	34.2	34.2	34.8	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2	34.2
Atlantic Canada	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. East Coast	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rockies	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8
Upper Midwest	8.0	9.9	11.8	14.7	16.9	16.5	11.2	4.4	19.7	8.0	18.8	31.7	44.4	48.7	53.4	54.8	47.9	50.2	56.7	63.9	69.6
Lower Midwest	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Continent	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Puget Sound	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
U.S. Gulf Coast	-	-	-	-	-	-	10.4	23.3	8.6	20.6	23.3	23.3	23.3	23.3	23.3	26.9	39.2	43.0	43.0	43.0	45.3
Northeast Asia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
India	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**129.5**	**131.9**	**134.5**	**137.0**	**139.2**	**139.4**	**143.8**	**149.9**	**150.6**	**150.8**	**164.3**	**177.2**	**189.9**	**194.3**	**198.9**	**204.0**	**209.4**	**215.4**	**222.0**	**229.2**	**237.1**

T A B L E A - 14

KEY NORTH AMERICAN CRUDE OIL PRICES

TRANS MOUNTAIN EXPANSION SCENARIO

(Real 2015 U.S. Dollars per Barrel, Unless Noted)

	2018	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*	*2031*	*2032*	*2033*	*2034*	*2035*	*2036*	*2037*	*2038*
Marker Crudes																					
Dated North Sea	82.23	83.92	85.00	86.28	87.57	88.88	90.22	91.57	92.94	94.34	95.75	97.19	98.65	99.14	99.63	100.13	100.63	101.14	101.14	101.14	101.14
Maya (FOB Cayo)	67.90	69.60	70.76	72.09	73.41	74.76	76.11	77.49	78.86	80.26	81.67	83.09	84.52	85.06	85.61	86.14	86.68	87.21	87.21	87.21	87.21
U.S. Crudes																					
West Texas Intermediate (Cushing)	73.92	75.33	76.41	78.14	79.69	81.82	83.09	84.67	86.38	87.84	89.14	91.08	92.61	93.36	94.12	94.93	95.57	96.19	96.24	96.19	96.19
Canadian Crudes @ Edmonton																					
Canadian Mixed Sweet	70.16	71.48	72.20	73.62	75.17	76.80	78.23	79.58	81.20	82.64	84.05	85.82	87.33	88.18	88.91	89.64	90.23	90.71	90.77	90.71	90.64
Canadian Mixed Sour	67.47	68.83	69.41	70.70	72.04	73.64	74.84	76.13	77.64	79.42	80.56	82.19	83.65	84.47	85.18	85.93	86.55	87.16	87.14	86.99	87.00
Sweet Synthetic	71.86	73.22	73.77	75.12	76.51	78.09	79.48	81.28	82.84	83.81	84.90	86.42	87.94	88.46	89.07	89.70	90.27	90.80	90.75	90.71	90.71
Sour Synthetic	67.74	69.00	69.61	71.45	72.76	73.68	74.50	75.78	77.11	78.08	79.17	79.89	80.22	80.39	81.06	81.40	81.22	81.79	81.79	81.54	81.23
Lloydminster Blend	59.09	60.18	60.63	61.04	62.51	63.84	64.55	65.69	66.91	67.67	68.81	70.47	71.85	72.24	72.76	73.48	73.88	74.35	74.35	74.30	74.20
Western Canadian Select	59.25	60.35	60.80	61.24	62.69	63.98	64.69	65.84	67.02	67.77	68.91	70.55	71.91	72.30	72.82	73.54	73.93	74.40	74.40	74.35	74.24
Cold Lake Blend	57.57	58.60	58.95	59.27	60.69	61.97	62.62	63.69	64.87	65.59	66.68	68.35	69.71	70.08	70.57	71.24	71.58	72.03	72.03	71.98	71.94
Athabasca DilBit	54.82	55.60	55.87	56.17	57.65	58.92	59.42	60.13	61.16	61.78	62.77	64.17	65.53	65.86	66.29	66.85	67.19	67.61	67.61	67.56	67.45
Athabasca SynBit	62.13	63.13	63.61	63.97	65.19	66.51	66.84	67.52	68.58	69.36	70.39	71.83	73.23	73.60	74.16	74.74	75.11	75.55	75.48	75.38	75.27
Canadian Crudes @ Hardisty																					
Lloydminster Blend	59.57	60.66	61.11	61.52	62.99	64.32	65.03	66.17	67.39	68.15	69.29	70.95	72.33	72.72	73.24	73.96	74.36	74.83	74.83	74.78	74.68
Western Canadian Select	59.73	60.83	61.28	61.72	63.17	64.46	65.17	66.32	67.50	68.25	69.39	71.03	72.39	72.78	73.30	74.02	74.41	74.88	74.88	74.83	74.72

T A B L E A - 15

KEY NORTH AMERICAN CRUDE OIL PRICES

BASE SCENARIO

(Real 2015 U.S. Dollars per Barrel, Unless Noted)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Marker Crudes																					
Dated North Sea	82.23	83.92	85.00	86.28	87.57	88.88	90.22	91.57	92.94	94.34	95.75	97.19	98.65	99.14	99.63	100.13	100.63	101.14	101.14	101.14	101.14
Maya (FOB Cayo)	67.90	69.60	70.76	72.09	73.41	74.76	76.11	77.49	78.86	80.26	81.67	83.09	84.52	85.06	85.61	86.14	86.68	87.21	87.21	87.21	87.21
U.S. Crudes																					
West Texas Intermediate (Cushing)	73.87	75.40	76.75	78.61	80.26	81.52	83.04	84.27	85.92	87.25	88.26	90.23	92.10	93.36	94.04	94.78	95.44	95.99	96.04	96.03	95.98
Canadian Crudes @ Edmonton																					
Canadian Mixed Sweet	68.52	69.97	71.04	72.57	74.14	75.74	77.29	78.69	80.49	82.05	83.07	84.98	86.64	87.80	88.40	89.16	89.88	90.43	90.45	90.42	90.35
Canadian Mixed Sour	65.82	67.08	68.15	69.49	70.78	72.17	73.60	74.92	76.74	78.40	79.49	81.32	82.91	84.05	84.57	85.47	86.12	86.76	86.74	86.70	86.55
Sweet Synthetic	69.47	70.79	71.66	73.28	74.86	76.43	77.89	79.35	81.15	82.80	83.92	85.54	87.21	88.30	88.96	89.60	90.13	90.74	90.72	90.72	90.68
Sour Synthetic	65.34	66.85	67.64	68.68	70.03	71.32	72.33	73.67	75.39	77.03	78.06	78.78	79.03	79.45	79.99	80.50	81.19	81.47	81.09	80.88	80.73
Lloydminster Blend	57.11	57.87	58.39	59.46	60.44	61.52	62.68	63.92	65.09	66.28	67.22	68.82	70.16	71.17	71.39	71.79	72.07	72.57	72.55	72.43	72.33
Western Canadian Select	57.23	58.00	58.48	59.52	60.47	61.59	62.79	64.03	65.21	66.41	67.35	68.95	70.27	71.28	71.49	71.92	72.20	72.70	72.67	72.56	72.44
Cold Lake Blend	55.37	56.06	56.53	57.52	58.48	59.57	60.65	61.80	62.93	64.01	64.91	66.42	67.70	68.68	68.87	69.15	69.40	69.89	69.86	69.73	69.62
Athabasca DilBit	52.48	53.11	53.30	53.84	54.68	55.67	56.67	57.76	58.81	59.82	60.66	62.10	63.32	64.26	64.41	64.63	64.86	65.30	65.28	65.14	64.96
Athabasca SynBit	57.11	57.95	58.72	59.33	60.69	62.19	63.85	64.18	66.13	67.18	68.06	69.54	70.76	71.73	71.90	72.15	72.40	72.92	72.84	72.70	72.51
Canadian Crudes @ Hardisty																					
Lloydminster Blend	57.59	58.35	58.87	59.94	60.92	62.00	63.16	64.40	65.57	66.76	67.70	69.30	70.64	71.65	71.87	72.27	72.55	73.05	73.03	72.91	72.81
Western Canadian Select	57.71	58.48	58.96	60.00	60.95	62.07	63.27	64.51	65.69	66.89	67.83	69.43	70.75	71.76	71.97	72.40	72.68	73.18	73.15	73.04	72.92

T A B L E A - 16

CANADIAN CRUDE OIL PRODUCER BENEFIT ESTIMATE

(Units as Noted)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
TMEP less Base Scenario Prices, Real 2015 U.S. Dollars																					
Canadian Mixed Sweet	1.63	1.51	1.16	1.05	1.04	1.07	0.94	0.89	0.71	0.59	0.98	0.84	0.69	0.38	0.51	0.47	0.35	0.29	0.32	0.30	0.29
Canadian Mixed Sour	1.65	1.75	1.26	1.21	1.25	1.47	1.24	1.21	0.90	1.02	1.07	0.87	0.73	0.42	0.61	0.46	0.43	0.40	0.40	0.29	0.45
Sweet Synthetic	2.38	2.43	2.11	1.84	1.65	1.66	1.59	1.93	1.69	1.00	0.98	0.88	0.73	0.16	0.12	0.11	0.14	0.05	0.03	(0.01)	0.03
Lloydminster Blend	1.99	2.31	2.23	1.57	2.07	2.31	1.88	1.78	1.82	1.38	1.59	1.65	1.68	1.07	1.37	1.69	1.80	1.78	1.80	1.87	1.87
Western Canadian Select	2.02	2.35	2.32	1.72	2.21	2.39	1.90	1.81	1.81	1.36	1.56	1.60	1.64	1.02	1.33	1.62	1.74	1.71	1.73	1.80	1.80
Cold Lake Blend	2.20	2.54	2.42	1.74	2.21	2.40	1.97	1.89	1.94	1.59	1.78	1.94	2.01	1.39	1.70	2.10	2.18	2.15	2.17	2.25	2.32
Athabasca DilBit	2.34	2.48	2.57	2.32	2.98	3.25	2.74	2.37	2.34	1.96	2.12	2.07	2.21	1.60	1.88	2.21	2.34	2.31	2.33	2.41	2.49
Athabasca SynBit	5.02	5.18	4.89	4.64	4.50	4.32	2.98	3.34	2.45	2.18	2.33	2.29	2.47	1.87	2.26	2.60	2.70	2.63	2.64	2.68	2.76
Sour Synthetic	2.40	2.15	1.97	2.77	2.74	2.36	2.17	2.11	1.72	1.05	1.11	1.12	1.18	0.94	1.07	0.90	0.03	0.32	0.70	0.66	0.50
Western Canadian Crude Oil Supply, kb/d																					
Canadian Light Sweet	433	432	435	439	441	444	447	449	452	456	460	464	467	470	474	477	481	484	486	488	490
Canadian Medium Sour	289	288	290	293	294	296	298	300	302	304	307	310	311	313	316	318	321	323	324	325	327
Sweet Synthetic	918	929	964	977	982	968	951	932	916	908	1,012	1,038	1,070	1,099	1,130	1,162	1,194	1,227	1,244	1,262	1,279
Subtotal Light	**1,639**	**1,648**	**1,690**	**1,709**	**1,717**	**1,708**	**1,696**	**1,681**	**1,669**	**1,668**	**1,779**	**1,812**	**1,847**	**1,883**	**1,919**	**1,957**	**1,995**	**2,035**	**2,055**	**2,075**	**2,096**
Conventional Heavy (LLB)	350	341	327	312	298	288	282	276	271	266	263	260	257	254	250	247	243	240	238	237	235
Western Canadian Select	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375
Cold Lake Blend	582	594	606	606	606	606	606	606	606	606	606	606	606	606	606	606	606	606	606	606	606
Athabasca DilBit	1,389	1,490	1,577	1,651	1,719	1,813	1,845	1,866	1,929	2,008	2,064	1,981	1,933	2,017	2,100	2,181	2,258	2,332	2,313	2,285	2,246
Athabasca SynBit	231	246	214	226	251	282	382	514	558	576	574	718	850	856	866	880	898	923	989	1,064	1,150
Sour Synthetic	130	132	134	137	139	139	144	150	151	151	164	177	190	194	199	204	209	215	222	229	237
Subtotal Heavy	**3,057**	**3,177**	**3,233**	**3,306**	**3,388**	**3,503**	**3,633**	**3,786**	**3,889**	**3,982**	**4,045**	**4,117**	**4,210**	**4,302**	**4,396**	**4,492**	**4,590**	**4,691**	**4,743**	**4,796**	**4,849**
Impact on Western Canadian Crude Oil Value, Millions of U.S. Dollars per Year																					
Canadian Light Sweet	43	238	185	168	167	173	154	146	117	98	165	142	117	64	88	82	61	51	57	53	43
Canadian Medium Sour	29	184	134	129	134	159	135	132	99	113	120	99	83	48	71	54	50	48	48	35	44
Sweet Synthetic	133	825	745	657	592	586	554	656	563	333	362	332	284	64	49	45	60	24	15	(5)	12
Subtotal Light	**206**	**1,247**	**1,064**	**955**	**894**	**917**	**844**	**933**	**780**	**544**	**648**	**573**	**484**	**176**	**208**	**181**	**172**	**123**	**119**	**82**	**99**
Conventional Heavy (LLB)	42	287	268	179	225	244	193	179	179	134	152	156	158	99	125	152	160	156	157	161	134
Western Canadian Select	46	322	318	236	303	328	261	248	247	187	214	219	225	140	182	222	238	234	238	246	205
Cold Lake Blend	78	550	535	385	488	531	436	417	429	350	394	428	444	308	376	464	481	474	481	497	428
Athabasca DilBit	198	1,349	1,482	1,400	1,867	2,151	1,852	1,616	1,650	1,439	1,598	1,496	1,558	1,176	1,442	1,761	1,925	1,965	1,975	2,013	1,701
Athabasca SynBit	71	465	383	383	413	444	417	627	499	458	490	600	766	585	715	833	886	885	954	1,041	964
Sour Synthetic	19	104	97	139	139	120	114	115	95	58	67	72	82	67	78	67	2	25	57	55	36
Subtotal Heavy	**455**	**3,076**	**3,082**	**2,722**	**3,435**	**3,817**	**3,275**	**3,202**	**3,099**	**2,627**	**2,916**	**2,971**	**3,233**	**2,375**	**2,919**	**3,499**	**3,693**	**3,739**	**3,862**	**4,013**	**3,467**
Total Impact	**660**	**4,323**	**4,146**	**3,677**	**4,329**	**4,734**	**4,118**	**4,136**	**3,878**	**3,171**	**3,563**	**3,544**	**3,717**	**2,551**	**3,127**	**3,680**	**3,865**	**3,862**	**3,981**	**4,095**	**3,566**
Days/Year	61	365	366	365	365	365	366	365	365	365	366	365	365	365	366	365	365	365	366	365	304

TABLE A-17

CANADIAN CRUDE OIL PRODUCER BENEFIT ESTIMATE

(Thousands of Canadian Dollars)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	Total
2015 Dollars																									
Canadian Light Sweet	-	-	-	43	238	185	168	167	173	154	146	117	98	165	142	117	64	88	82	61	51	57	53	43	2,413
Canadian Medium Sour	-	-	-	29	184	134	129	134	159	135	132	99	113	120	99	83	48	71	54	50	48	48	35	44	1,948
Sweet Synthetic	-	-	-	133	825	745	657	592	586	554	656	563	333	362	332	284	64	49	45	60	24	15	(5)	12	6,887
Subtotal Light	**-**	**-**	**-**	**206**	**1,247**	**1,064**	**955**	**894**	**917**	**844**	**933**	**780**	**544**	**648**	**573**	**484**	**176**	**208**	**181**	**172**	**123**	**119**	**82**	**99**	**11,247**
Conventional Heavy (LLB)	-	-	-	42	287	268	179	225	244	193	179	179	134	152	156	158	99	125	152	160	156	157	161	134	3,543
Western Canadian Select	-	-	-	46	322	318	236	303	328	261	248	247	187	214	219	225	140	182	222	238	234	238	246	205	4,857
Cold Lake Blend	-	-	-	78	550	535	385	488	531	436	417	429	350	394	428	444	308	376	464	481	474	481	497	428	8,976
Athabasca DilBit	-	-	-	198	1,349	1,482	1,400	1,867	2,151	1,852	1,616	1,650	1,439	1,598	1,496	1,558	1,176	1,442	1,761	1,925	1,965	1,975	2,013	1,701	33,615
Athabasca SynBit	-	-	-	71	465	383	383	413	444	417	627	499	458	490	600	766	585	715	833	886	885	954	1,041	964	12,878
Sour Synthetic	-	-	-	19	104	97	139	139	120	114	115	95	58	67	72	82	67	78	67	2	25	57	55	36	1,608
Subtotal Heavy	**-**	**-**	**-**	**455**	**3,076**	**3,082**	**2,722**	**3,435**	**3,817**	**3,275**	**3,202**	**3,099**	**2,627**	**2,916**	**2,971**	**3,233**	**2,375**	**2,919**	**3,499**	**3,693**	**3,739**	**3,862**	**4,013**	**3,467**	**65,476**
Total Impact	**-**	**-**	**-**	**660**	**4,323**	**4,146**	**3,677**	**4,329**	**4,734**	**4,118**	**4,136**	**3,878**	**3,171**	**3,563**	**3,544**	**3,717**	**2,551**	**3,127**	**3,680**	**3,865**	**3,862**	**3,981**	**4,095**	**3,566**	**76,724**
2012 Dollars																									
Canadian Light Sweet	-	-	-	41	228	177	161	160	165	148	140	113	94	158	136	112	62	84	79	59	49	54	50	41	2,311
Canadian Medium Sour	-	-	-	28	176	128	124	129	152	130	126	95	108	115	94	80	46	68	51	48	46	46	33	42	1,866
Sweet Synthetic	-	-	-	128	791	713	630	568	561	531	628	539	319	347	318	272	61	47	43	58	23	14	(5)	12	6,597
Subtotal Light	**-**	**-**	**-**	**197**	**1,194**	**1,019**	**915**	**856**	**879**	**808**	**894**	**747**	**522**	**620**	**549**	**464**	**169**	**199**	**173**	**165**	**118**	**114**	**78**	**95**	**10,774**
Conventional Heavy (LLB)	-	-	-	41	275	256	172	216	233	185	171	172	129	146	150	152	95	120	146	153	149	151	155	128	3,394
Western Canadian Select	-	-	-	44	308	305	226	290	314	250	237	237	179	205	209	215	134	174	212	228	224	228	235	196	4,652
Cold Lake Blend	-	-	-	75	527	513	369	468	509	418	400	411	336	377	410	425	295	361	444	461	454	461	476	410	8,598
Athabasca DilBit	-	-	-	190	1,293	1,419	1,341	1,788	2,060	1,774	1,548	1,581	1,378	1,531	1,433	1,493	1,126	1,382	1,687	1,844	1,882	1,892	1,928	1,629	32,201
Athabasca SynBit	-	-	-	68	445	366	367	395	425	400	601	478	439	470	575	734	560	685	798	849	848	914	997	923	12,337
Sour Synthetic	-	-	-	18	99	93	133	133	115	110	110	91	56	64	69	79	64	74	64	2	24	54	53	34	1,540
Subtotal Heavy	**-**	**-**	**-**	**436**	**2,947**	**2,953**	**2,607**	**3,290**	**3,657**	**3,137**	**3,067**	**2,969**	**2,516**	**2,793**	**2,846**	**3,097**	**2,275**	**2,797**	**3,352**	**3,537**	**3,582**	**3,700**	**3,844**	**3,321**	**62,723**
Total Impact	**-**	**-**	**-**	**633**	**4,141**	**3,972**	**3,522**	**4,147**	**4,535**	**3,945**	**3,962**	**3,715**	**3,038**	**3,413**	**3,395**	**3,561**	**2,443**	**2,996**	**3,525**	**3,702**	**3,700**	**3,814**	**3,923**	**3,416**	**73,497**

Net Present Values (2012$)	
Discount Rate (Real)	
3%	**49,146**
5%	**38,438**
8%	**27,405**
10%	**22,273**

APPENDIX B — CURRICULUM VITAE

NEIL K. EARNEST

SUMMARY OF EXPERIENCE:

Neil has over 30 years of experience focused on the downstream sector of the energy business, and has played key roles in major international arbitrations, multi-billion dollar downstream asset acquisitions, and Canadian crude marketing and upgrading programs totaling hundreds of thousands of barrels per day. As a consultant, he has worked on a broad range of assignments around the world with an emphasis on asset acquisition and divestitures, crude and refined product marketing analyses, expert testimony in support for highly complex arbitrations and major pipeline projects, and project feasibility assessment. Neil began his career at Phillips Petroleum Company, where he spent 11 years in a variety of roles at Phillips' largest refinery and petrochemical plant and in corporate planning/engineering.

REPRESENTATIVE CONSULTING EXPERIENCE:

Asset Acquisition and Divestitures

As director of the M&A practice area, has frequently headed Muse's teams that have assisted clients contemplating downstream acquisitions or divestitures. Over the years, dozens of detailed valuations of North American refineries for a variety of clients have been completed. Several representative assignments follow:

1. Provided a detailed technical and economic assessment of the range of options available to a Canadian heavy crude producer commencing a downstream integration strategy. Assistance included board-level presentations and assistance negotiating the purchase-sales agreements and the joint-venture operating agreements.
2. Developed a detailed valuation of the combined sales value of the European downstream assets of a major oil company. Included projecting refinery cash flow considering the evolving environmental, product demand, and product specification issues regarding Europe.
3. Provided economic, technical, and LP modeling assistance to a corporate team considering entry into the Asia-Pacific refining industry.
4. Conducted due diligence of, and assessed the potential for, investment in four state-owned African refineries.
5. Assisted a U.S. client considering the merger of their refining assets with another refiner. The assistance included an assessment of the competitive position of the potential merger partner.

Market, Strategic, and Competitive Analysis

Have provided a broad range of market and competitive analyses in support of client's strategy objectives. Clients include pipeline companies, refiners, and crude producers. Several representative examples include:

1. Assisted a number of Canadian crude producers with their development strategy, including detailed market and potential customer assessments, for their synthetic and heavy sour crude programs.
2. On behalf of several refiners, developed a detailed assessment of their competitive position versus domestic and foreign competition.
3. Generated a detailed assessment, considering multiple market scenarios, of the expected prices for a range of potential synthetic crude formulations that was instrumental in finalizing the design basis for a multi-billion dollar Canadian oil sands upgrader.
4. Assisted a client with the development of a marketing program for a new, high acid, North Sea crude.
5. Provided the market analysis in support of a new proposed product pipeline in the Rockies.
6. Assisted several clients with quantifying the value of their equity crude to specific purchasers. The purchasers were either being considered for term contracts or were large volume buyers.
7. Provided the Government of Alberta, Ministry of Energy, detailed analysis of bitumen blends and targeted markets.

Project Feasibility Analysis

Representative project and refinery feasibility analyses include:

1. In-depth evaluation of resid upgrading options for a large Middle East refinery.
2. Provided a detailed assessment of the value of a partial-upgraded biofuel to the refining industry on behalf of the biofuel manufacturer.
3. Provided a detailed technical and economic assessment of a heavy crude partial upgrader, including certifying field-scale performance tests.
4. Developed the configuration, yields, and operating costs for a proposed Middle East refinery.
5. Performed a detailed study for a U.S. client considering various resid upgrading options.
6. Assisted a South American client with process optimization in connection with a major upgrade of their lube manufacturing facilities.
7. Performed a technical and economic analysis for a South American client considering the construction of a resid FCC unit.

Expert Testimony

1. Private Arbitration (1998): Koch Shipping Inc., Koch Supply & Trading Company, and Koch Refining Company, L.P. v. Mobil Shipping and Transportation Company.

2. Provided expert report, in 2006, on behalf of Enbridge Pipelines regarding the market demand for Canadian crude oils and quantified the benefits that would flow to Illinois and other U.S. consumers regarding the Southern Access Pipeline. Report filed with the Illinois Commerce Commission.

3. Provided expert report and direct testimony before the National Energy Board (Canada) regarding the Southern Lights Project, on behalf of Enbridge Pipelines, Inc., with hearings held in Calgary, Alberta, in 2007.

4. Expert report and direct testimony before the National Energy Board (Canada) regarding the Alberta Clipper Project, on behalf of Enbridge Pipelines, Inc., with hearings held in Calgary, Alberta, in 2007.

5. Provided expert report, in 2007, on behalf of Enbridge Pipelines to the National Energy Board (Canada) regarding the crude supply and demand for Ontario and Montréal refineries.

6. Provided expert reports, in 2007, to the U.S. Federal Energy Regulatory Commission on behalf of Enbridge Pipelines regarding the expected utilization of the Southern Access Extension pipeline, as well as other non-rate shipper benefits that ensued from the commissioning of the pipeline. Also provided written affidavit in response to intervener's expert.

7. Provided direct testimony, in 2008, before the Minnesota Public Utilities Commission regarding the Alberta Clipper Project, on behalf of Enbridge Pipelines, Inc.

8. Direct testimony, in February 2008, before the International Court of Arbitration, with hearings held in Zurich, Switzerland, on behalf of Louis Dreyfus S.A.S. (Respondent) against Ronald W. de Ruuk, as Bankruptcy Administrator for Holding Tusculum B.V., (Claimant). Testifying expert at hearings on behalf of the respondent regarding the value of the Wilhelmshaven, Germany, refinery. Also co-authored valuation report and responses to claimant's experts. Approximate damage claim: US$300 to 500 million.

9. Provided expert report, in May 2009, and oral testimony to the International Court of Arbitration on behalf of Mobil Cerro Negro, Ltd (Claimant) against Petroleos de Venezuela, SA regarding the expropriation of assets; multi-billion dollar damage claim.

10. Expert report and direct testimony before the National Energy Board (Canada) regarding the Keystone XL Project, on behalf of Enbridge Pipelines, Inc., with hearings held in Calgary, Alberta, in 2009.

11. Provided expert and reply report, in 2009, on behalf of Enbridge Pipelines to the National Energy Board (Canada) regarding the medium-term prospects for Line 9 in westbound service.

12. Provided expert and reply reports, in 2010 and 2011, to the International Centre for Settlement of Investment Disputes on behalf of Venezuelan Holdings B.V., et.al. (Claimant) against the Bolivarian Republic of Venezuela, and oral testimony at the hearing held in Paris in 2012 regarding the expropriation of assets; multi-billion dollar damage claim.

13. Provided expert oral testimony in 2011 on behalf of Enbridge Inc. to the National Energy Board (Canada) regarding the Southern Lights Pipeline.

14. Provided expert report, in 2011, on behalf of Enbridge Bakken Pipeline Company to the National Energy Board (Canada) regarding the market prospects for North Dakota crude oil.

15. In 2011, submitted expert and rebuttal reports to the U.S. Federal Energy Regulatory Commission on behalf of Enbridge Pipelines regarding the Southern Lights Pipeline followed by oral testimony at the hearing in Washington, D.C., in 2012.

16. Provided expert and rebuttal reports to the Joint Review Panel (Canada) regarding the Northern Gateway Pipeline project, followed by oral testimony at hearing held in Edmonton, Alberta in September 2012, on behalf of the Northern Gateway Pipeline.

17. Provided expert report to the National Energy Board (Canada) regarding the market prospects for the Enbridge Edmonton-to-Hardisty pipeline project in November 2012, followed by direct testimony in October 2013, on behalf of Enbridge Pipelines.

18. Provided expert report, rebuttal, and surrebuttal testimony in 2013 and 2014 before the Minnesota Public Utilities Commission regarding the Line 67 Station Expansion Project – Phase 2, on behalf of Enbridge Pipelines, Inc.

19. Provided expert report and rebuttal testimony in 2014 to the U.S. Federal Energy Regulatory Commission on behalf of North Dakota Pipeline Company LLC regarding the Sandpiper pipeline.

20. In June 2014, provided written and oral expert testimony in the English High Court of Justice – Commercial Court, on behalf of Innospec Inc. versus Jalal Bezee Mejel Al-Gaood & Partner regarding issues in the Iraqi refining sector.

21. Provided expert and rebuttal testimony to the National Energy Board (Canada) regarding Trans Mountain Pipeline nomination verification procedures in 2014, on behalf of Tesoro Canada.

22. Provided expert reports and oral testimony in August 2014 through January 2015 before the Minnesota Public Utilities Commission regarding the Sandpiper Pipeline Project on behalf of North Dakota Pipeline Company LLC.

23. Provided expert report and rebuttal report in August and September, 2014 in the U.S. District Court for the Central District of California, on behalf of Southern California Edison Company versus ExxonMobil Oil Corporation.

24. Provided reply report in October 2014 to the International Centre for Settlement of Investment Disputes on behalf of ConocoPhillips Petrozuata B.V., et.al. (Claimant) against the Bolivarian Republic of Venezuela regarding the expropriation of assets; multi-billion dollar damage claim.

25. Proved an expert report in November 2014 to the National Energy Board (Canada) regarding the expected utilization of the Enbridge Mainline for the Enbridge Line 3 Replacement Program.

26. Provided expert report in June 2015 to the International Court of Arbitration on behalf of Wallis Trading Inc. versus SGS Societe Generale de Surveillance SA for a case regarding issues relating to a collateral management agreement at an Albanian storage facility.

WORK EXPERIENCE:

Muse, Stancil & Co. 1991 - Present
Current Position: President

Phillips Petroleum Company 1981-1991
Positions:
Process Senior Engineer
Economics Engineer
Staff Process Engineer

EDUCATION: B.S. Chemical Engineering - 1981
Michigan State University
M.B.A. - 1986
University of Houston – Clear Lake

PROFESSIONAL REGISTRATION: Chemical Engineer, Texas, #75398

PUBLICATIONS/PRESENTATIONS:

1. *"Refinery-Profitability Statistics Begin"*
   Oil & Gas Journal
   January 2001

2. *"Canadian Crude Market Outlook"*
   Alberta Department of Energy Workshop #2
   March 2002

3. *"View from the Market: The Refiner's Perspective"*
   CERI 2003 World Oil Conference
   January 2003

4. *"Traditional Markets and New Opportunities"*
   CERI 2004 World Oil Conference
   March 2004

5. *"Independent Views on Markets for Oil Sands and Pipeline Capacity"*
   TD Newcrest Oil Sands Forum 2004
   July 2004

6. *"Independent Views of Markets for Oil Sands and Pipeline Capacity"*
   2004 National Petrochemical & Refiners Association
   July 2004

7. *"The Canadian Crude Market"*
   2005 Canadian Crude Oil Conference
   September 2005

8. *"The Canadian Crude Market*
   3rd Annual Canadian Oil Sands Summit
   January 2006

9. *<u>"Bigger is Better"</u>*
4th Annual Oil Sands Forum – Oil Sands Market Overview
July 2006

10. *<u>"U.S. Market for Canadian Crude – Oil Sands Market Overview</u>*
Crude Oil Quality Group General Meeting
November 2006

11. *<u>"Future Markets for Canadian Crude</u>*
4th Annual Canadian Oil Sands Summit
January 2007

12. *<u>"Canadian Crude Market Outlook"</u>*
3rd Annual Enbridge Mid-Continent Shippers Conference
January 2007

13. *<u>"New Market Outlook for Canadian Crude"</u>*
42nd Annual Enbridge Jasper Conference
June 2007

14. *<u>"Canadian Oil Market – Opportunities and Challenges"</u>*
5th Annual Canadian Oil Sands Summit
January 2008

15. *<u>"Canadian Crude Market and Outlook"</u>*
Argus US/Canada Asphalt Conference 2008
April 2008

16. *<u>"Oil Sands Integration with the U.S. Market – A Revised Perspective"</u>*
20th Annual Canadian Crude Oil Conference
September 2008

17. *<u>"The Economy and Oil Demand: Where are They Taking the Oil Market?"</u>*
CERI 2009 Oil Conference
April 2009

18. *<u>"Oil Sands Integration with the Global Markets – A Revised Perspective"</u>*
TD Newcrest London Oil Sands Forum 2009
January 2009

19. *<u>"Oil Sands Integration with the Global Markets"</u>*
TD Newcrest Canadian Unconventional Oil Forum 2009
July 2009

20. *<u>"Implications of Expanding Canadian Pipeline Infrastructure"</u>*
Argus Americas Crude Summit 2010
January 2010

21. *<u>"Counter-Party Risk"</u>*
T.D. Newcrest – Unconventional Oil & Gas Forum
July 2010

22. *"U.S. Downstream in the New Economic Reality"*
Annual Canadian Crude Oil Conference
September 2010

23. *"The Road to Recovery"*
Argus 4th Annual Americas Asphalt Summit
March 2011

24. *"Crack Spreads are Back: Which PADDs Stand to Benefit and How Long Will It Last?"*
TD Securities – Unconventional Energy Conference
T.D. Newcrest – 2011 Calgary Unconventional Energy Conference
July 2011

25. *"Overall Market Landscape for Canadian Crude Oil"*
Argus – Americas Crude Summit 2012
January 2012

26. *"Canadian Crude Landscape and Market Expansion Prospects"*
Argus – Americas Asphalt Summit 2012
March 2012

27. *"The Changing Crude Supply Landscape – The Refiner's Perspective"*
TD Securities
July 2012

28. *"Rail vs. Pipeline: What Projects are Being Developed to Accommodate Growing Shale Crude Production?"*
Argus Americas Crude Summit
January 2013

29. *"Implications of the North American Oil Renaissance"*
American Fuel & Petrochemical Manufacturers
January 2013

30. *"Implications of the Evolving North American Crude Supply Outlook"*
TD Securities – 2013 TD Calgary Energy Conference
July 2013

31. *"Implications of the Evolving North American Crude Supply Outlook"*
AICHE –5th Southwest Process Technology Conference
October 2013

32. *"Renaissance of the North American Energy Sector"*
Lloyds Register – Energy Conference
October 2013

33. *"Changing Topography of U.S. Crude"*
Argus – Americas Crude Summit 2014
January 2014

34. *"Canadian Tidewater Access – Implications for the U.S."*
American Fuels & Petrochemical Manufacturers Annual Meeting 2014
March 2014

35. *“Dealing with an Oversupply of Light Crudes in a World of Heavy Crude Refineries”*
Canadian Energy Research Institute 2014 Oil Conference
April 2014

36. *“Market Access and Storage Constraints”*
Argus Canadian Crude Summit 2015
June 9, 2015

37. *“North American Crude Market Outlook”*
Enbridge 50th Annual Liquids Pipelines Conference 2015