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# **A NETBACK IMPACT ANALYSIS OF WEST COAST EXPORT CAPACITY**

**For** 

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**Department of Energy** 

**By** 

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## **Netback Impact Analysis Of West Coast Export Capacity**

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## **NETBACK IMPACT ANALYSIS OF WEST COAST EXPORT CAPACITY**

The province of Alberta's Department of Energy requested from Wood Mackenzie Incorporated (Wood Mackenzie) an expert report to estimate an order of magnitude impact on crude oil netbacks received by Canadian producers, in Alberta, from increasing West Coast crude oil export capacity. Wood Mackenzie used the proposed Enbridge "Northern Gateway" pipeline project as a proxy to assess the potential impact of additional crude oil export capacity to the west coast. The proposed Northern Gateway Pipeline would run from Bruderheim (near Edmonton) to Kitimat with a return condensate pipeline for importing oil sands diluent material. This paper describes our analysis and conclusions on the impact on the netback to Alberta crude oil producers within the early years of service (2016-2025) based on our methodology described herein.

#### **EXECUTIVE SUMMARY**

Given Wood Mackenzie's heavy crude production profile forecast, Canadian producers require additional pipeline capacity to export incremental production volumes of heavy crude oil to key demand centres. Canadian pipeline companies are considering a myriad of projects to provide potential solutions for Canadian crude oil producers to have sufficient access to appropriate refining markets.

Wood Mackenzie used the proposed Enbridge "Northern Gateway" pipeline project as a proxy to assess the potential impact of additional West Coast crude oil export capacity. This proposed pipeline would transport an estimated 525 thousand barrels per day (kbd) from Edmonton to Kitimat. Wood Mackenzie expects growing heavy crude oil production in the Western Canadian Sedimentary Basin (WCSB) to require additional diluent for blending to enable the bitumen to meet pipeline density and viscosity requirements. Thus incremental diluent sources in to the WCSB are required to support the export of diluted oil sands bitumen. As such, Wood Mackenzie also considered a return diluent pipeline.

Wood Mackenzie's assessment of adding West Coast crude oil export capacity results in the following substantive findings:

- Additional export capacity connected to heavy crude refining markets is needed to place growing Canadian oil production by 2017;
- Tidewater access provides an important link to the significant and fast-growing Asian market;
- Asia is an attractive market for Alberta production on a netback basis



• Canadian producers not having sufficient access to premium heavy crude refining markets could lose about \$8/bbl for every Canadian heavy crude barrel, with a revenue impact averaging C\$8 billion per year for 2017 to 2025.

#### **INTRODUCTION**

The outlook for crude oil production from the Western Canadian Sedimentary Basin (WCSB), suggests producers are likely to require additional access to a variety of refining markets to sufficiently place incremental volumes of heavy crude oil. A number of Canadian logistics companies are considering a myriad of projects to address the need for additional market access. Wood Mackenzie assessed the potential impact of adding a west coast tidewater access, considering a pipeline connecting Edmonton to Kitimat with a return condensate pipeline as shown in Figure 1, on Alberta crude oil producers' netbacks within the early years of service (2016-2025). The analysis is based on Enbridge's Northern Gateway Pipeline Project and was developed in consideration of existing pipeline capacity and announced projects expected to be commissioned within the period of study. Wood 41 Mackenzie analyzed the potential impact of this West Coast option to heavy Canadian crude oil (e.g., oil sands) values netted back to crude terminals in the Canadian province of Alberta at Edmonton or Hardisty, depending on the crude stream.

This report presents our conclusions based on the methodology described herein. All prices, unless specifically noted, are expressed in real (i.e., inflation adjusted) 2010 US dollars.







## **GLOBAL HEAVY CRUDE MARKET**

Globally, heavy crude oil production is set to grow significantly over the next decade. Production growth in some regions will be somewhat off-set by decline in other regions. The estimated net increase in global production is expected to reach over 3,000 kbd between 2010 and 2025, with growth led by the Middle East and Canada as shown in Figure 2. Middle Eastern heavy crude production is projected to be dominated by Saudi Arabia's "Arab Heavy" blend with total production from this region expected to almost triple from 2010 – reaching nearly 6,000 kbd in 2025 with a 52 compound annual growth rate (CAGR) of 7% per annum.<sup>1</sup> Canadian production grows at a compound annual growth rate of approximately 5% per annum. Both of these regions grow substantially faster 54 than other parts of the world, with some regions (e.g., U.S and Mexico) expecting heavy crude oil production to decline nearly 2% per annum. Asia's heavy crude oil production is expected to decline more rapidly (at nearly 4% per year) by 2025 production in this region is expected to be almost 50% below total current production.





<sup>&</sup>lt;sup>1</sup> For comparison, the Wood Mackenzie oil sands production forecast is more conservative than the CAPP "Crude Oil Forecast, Markets and Pipelines (June 2011), ERCB (ST-98 2011), and the NEB (November 2011). Over the 2010 to 2020 forecast period Wood Mackenzie oil sands production averages ~65 kbd less than these alternate outlooks. The largest difference is relative to the ERCB forecast, in which Wood Mackenzie averages ~130 kbd less oil sands production for 2010 to 2020.



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Canada is expected to become an increasingly important source of heavy crude oil production in the world. Figure 3 represents the total net change in production by 2025 with Canada representing nearly 20% of total global heavy crude oil production growth. By 2025 Canadian heavy crude production volumes could reach nearly 3,000 kbd, primarily dominated by unconventional grades. Canada could be the third largest heavy crude oil producer after Saudi Arabia and Iraq, while both the countries of the Former Soviet Union (FSU) and Brazil make modest net contributions.<sup>2</sup> 63



**Figure 3: Regional Heavy Crude Oil Production Change 2010 – 2025** 

#### **Alberta Crude Oil Production Profile**

Canada's crude oil production is mainly concentrated in the WCSB and Alberta is home to the largest conventional hydrocarbon resources in Canada and to the world's largest single hydrocarbon deposit, the Athabasca oil sands. Canada's role as the largest single supplier of crude oil to the US is projected to become increasingly prominent. North America heavy crude oil production is expected to be dominated by declining Mexican grades and increasing Canadian unconventional production.

69 For several years there has been significant activity in oil sands development. New technologies, 70 favourable fiscal terms and a high oil price environment all encouraged companies to invest their

<sup>&</sup>lt;sup>2</sup> Heavy crude from the FSU will be mainly sour (sulphur greater than 1% by weight), similar to Canada and the Middle East), while Brazil's productions increases will tend be sweet (sulphur less than 1%).



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capital in Alberta's oil sands. The availability of labour, equipment, and natural gas in addition to a significant drop in commodity prices deterred investments during the recent economic downturn (2008-2009) – as a result, a number of operators opted to defer, cancel or redefine their oil sands portfolios and aspirations. However, the year 2010 gave way to a more positive turn for producers as markets steadily rebounded allowing producers to continue their path forward with more balanced production estimates.

Figure 4 shows Wood Mackenzie's production forecast for west Canadian crude oil supply from 2010 to 2025. The forecast reflects a series of projects (primarily oil sands) which have made or are in the process of making financial commitments, such as Husky-BP's Sunrise, Imperial Oil's Kearl, Statoil's KKD-Leismer. Western Canada's production profile changes by adding these projects (on an unrisked basis). There are a number of upgrader projects that have been announced and are in various degrees of development. For the purposes of this analysis, Wood Mackenzie assumes there is 100 kbd of new upgrading capacity for bitumen to synthetic crude oil (SCO) added over this time frame. Crude oil production grows to an estimated 4,000 kbd bpd by 2021 with oil sands production reaching nearly 2,800 kbd and synthetic crude oil production of approximately 900 kbd.



**Figure 4: Canadian Heavy Crude Oil Production 2010 – 2025** 

On the crude oil demand side, the US is the largest single export market for Canada. The U.S petroleum market is divided into five regions known as the Petroleum Administration for Defense 88 Districts (PADDs). These regions are PADD I – covering the East Coast, PADD II – includes the refining centres within the Midwest, PADD III – the Gulf Coast, PADD IV – covering the Rocky



Mountains and PADD V – the West Coast including Alaska and Hawaii. Wood Mackenzie analyzed the disposition of Canadian heavy crude supply to the main demand centres within Canada and the U.S. through the existing export pipeline systems considering the current pipeline capacities and their planned expansions wherever applicable. Wood Mackenzie assesses the disposition of Canada's western crude oil production based on the rate at which crude is processed through those refineries. In this analysis, we assume each refining nameplate capacity is utilized at 95%, and this crude distillation capacity is operative 95% of the year. Thus the effective annual utilization rate per refining centre is 90.3%. By comparison, the Energy Information Administration of the U.S. Department of Energy reports U.S. refinery operating utilization in the second quarter of 2011 was 85.8%. Thus the assumptions used in this analysis result in a robust local demand for crude oil, which is a conservative view of when incremental West Coast pipeline capacity might be necessary.

Pipelines are designed for different types of service, namely to ship specific types of crude (i.e., light, heavy) and in some cases serve a mixed blend of qualities. Wood Mackenzie considers a series of assumptions as to how light and heavy crudes are allocated in these mixed service lines. We estimate the allocation of heavy and light based on contractual commitments and the necessary volumes to fulfil shipper's needs. The flow of production through various pipeline routes is set by the supply of crude exports from the WCSB and the demand for respective crude types within each refining centre.

Western Canada crude oil production largely is delivered to two hubs located in Edmonton and Hardisty, Alberta. These two hubs feed four major pipeline networks: Enbridge Mainline, Kinder Morgan Express, Kinder Morgan Trans-Mountain, and TransCanada Keystone. Edmonton is considered as the major refining centre in Western Canada, in this analysis. Supply volumes from Western Canada to the U.S. markets fills roughly from a north to south basis departing from the two main hubs and transported by four major pipeline networks: Enbridge, Kinder Morgan Express, Kinder Morgan Trans Mountain, and TransCanada Keystone with other U.S pipelines providing connectivity across the main U.S hubs (i.e., Cushing, Patoka):

The Enbridge network is a complex pipeline system in Western Canada, comprised of the Enbridge Canadian Mainline starting at Edmonton, Alberta and ending at Gretna, Manitoba. This system then connects to Enbridge's Lakehead system, which continues in to the Chicago area, delivering crude to the U.S. Midwest (PADD II). The Enbridge Pipeline system has expanded over time with most recent expansions adding capacity through Lines 2, 4, 61. The reversal of Line 13; comprising capacity for the Southern Lights condensate project, was more than offset by the addition of 450 kbd from the Alberta Clipper pipeline in 2010. The result of these expansions makes this system the longest crude



oil and petroleum products pipeline system in the world. It transports light, synthetic, medium and heavy crudes to refineries in the US Midwest and Ontario, and has a balanced capacity upstream and downstream of Superior of nearly 2,000 kbd.

The Trans Mountain system owned by Kinder Morgan connects Edmonton to Vancouver, and further links into Washington State on the US West Coast, with a capacity of nearly 300 kbd. Any potential expansion of the Trans Mountain system is not considered in this analysis. In October 2011 Kinder Morgan Canada began an open season on an expansion of up to 400 kbd for Trans Mountain. This additional capacity is not included in this analysis. Both Northern Gateway and the Trans Mountain expansion would open new tidewater access to Pacific Basin crude oil markets.

The Express System transports crude oil from Hardisty, Alberta to Wood River Illinois with a capacity of around 320 kbd carrying light, medium and heavy crude to markets in the Rockies (PADD IV), and through a connection in the US, gives access to Midwest markets (PADD II).

The Keystone Pipeline operated by TransCanada transports up to 590 kbd of crude oil between Hardisty to Wood River and Patoka, Illinois. The analysis includes the February 2011 completion of the Cushing extension. TransCanada is currently developing the Keystone Gulf Coast Expansion project (Keystone XL) which would begin in Hardisty and extend to US Gulf Coast markets at Nederland, Texas, which connects to refineries in the Port Arthur, Texas area with a total of 700 kbd of export capacity by 2013. In November 2011, the US government announced it is delaying until early 2013 a decision on granting a Presidential Permit to cross the Canada-US border. Given the political uncertainty surrounding approval of this pipeline, Wood Mackenzie excludes Keystone XL within the analysis providing additional heavy crude oil connectivity to PADD III refineries.

Other U.S pipelines considered to serve the broader refining centres are the Mustang System, the Spearhead system, and the Pegasus Pipeline owned by ExxonMobil. The Mustang System serving from the Lakehead Mainline in Chicago to Patoka, Illinois has a capacity of 100 kbd. The Spearhead Pipeline system, reversed in 2006, enables crude flows from Chicago to Cushing with a 193 kbd of capacity. The Pegasus Pipeline transports heavy crude from Patoka to the US Gulf Coast with a capacity of 96 kbd.

In November 2011, Enbridge announced it was buying ConocoPhillips' 50 percent interest in the Seaway Pipeline. This pipeline currently runs from the USGC inland to Cushing, Oklahoma. However, Enbridge and their Seaway Pipeline partner Enterprise Products Partners L.P. subsequently announced their intention to reverse the pipeline to evacuate crude oil from Cushing to the USGC. The current plan is to reverse the line by mid-2013 with a capacity of 150 kbd. Wood Mackenzie



assumes the reversed Seaway begins shipping light crude from Cushing in mid-2013 and then shifts to mixed service as necessary up to a capacity of 400 kbd.

The export routes mentioned previously define the heavy crude oil supply disposition from western Canada to the US Midwest, Ontario, the Rockies, and the West Coast and Gulf Coast refineries. Given the growth profile of the Canadian production Wood Mackenzie fills heavy crude supply on the basis of the heavy service capacity pipelines until supply is exhausted, demand is satisfied, or pipeline capacity is filled. Disposition on these pipelines also considers a number of upgrading projects to which refiners have publicly committed to across the U.S. (i.e., ConocoPhillips-Cenovus at Wood River, IL, BP at Whiting, IN and Marathon at Detroit, MI). These projects have been set to heavy the crude slate by adding or increasing deep conversion capacity (i.e., coker units). The commencement of these projects by 2012 is expected to significantly increase heavy crude oil demand as BP-Whiting increases heavy crude oil demand by an additional 260 kbd, and Wood River by another 150 kbd; Marathon's Detroit project increases demand by only 15 kbd.

Figure 5 indicates the disposition of heavy crude production to each major refining centre within Canada and across the U.S. The portion of Canadian refinery crude oil demand considered by Wood Mackenzie in this analysis as those refineries in Western Canada and Eastern Canada (comprising 171 refineries located in Nanticoke and Sarnia) fed by the Enbridge pipeline system.<sup>3</sup> The northern PADD II demand is considered to be fulfilled by the Enbridge pipeline system serving the refineries located in Saint Paul, Superior, Chicago, Detroit, Toledo and those refineries served by the Mustang and Spearhead pipeline systems; with some volumes supplied on Keystone at Wood River/Patoka and Cushing. Southern PADD II, centred at Patoka and Cushing has more pipeline capacity than heavy crude demand. However, as refineries in the Gulf Coast have substantial refining capacity to handle heavy gravity crude and are dependent on international (waterborne) imports to supplement domestic supply, the Pegasus pipeline and connectivity through Cushing via Seaway would provide connectivity to refineries in Port Arthur thus granting further access to a greater demand within PADD III refineries. PADD IV demand is served by the Express Pipeline System and the Trans Mountain system services the Vancouver and Washington State markets.

 Enbridge has filed notice to reverse Line 9, which would enable Enbridge to carry crude oil from Sarnia, Ontario to Westover, Ontario.



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**Figure 5: Western Canada Heavy Crude Oil Disposition 2010 – 2020** 

Wood Mackenzie's western Canada's heavy crude oil disposition analysis estimates that diluted oil sands could fail to reach sufficient access to premium heavy crude markets by 2017 as pace of production far exceeds pipeline capacity to major heavy crude oil demand centres. Failure to reach these heavy crude refining centres could result in the need to discount the price of Canadian heavy crude to place the volumes in markets. Current connected markets are thus able to absorb Canada's heavy crude oil production until about 2016 when improved access is needed to connect Canadian production volumes to new markets such as those corresponding to the Asia-Pacific region.

#### **Global heavy crude oil ideal balance**

Our global view of heavy crude oil demand and supply suggest Asia Pacific and North America are key deficit markets of heavy crude oil going forward. The Middle East, on the other hand is becoming a significant surplus region. A significant contribution to the heavy crude oil deficits in Asia Pacific and 192 North America is the growth in 'ideal' capacity for processing heavy oils.<sup>4</sup> For heavy crude oil it is based on the structural refinery demand for vacuum residue material, and an assumed vacuum residue yield on crude of 30% by volume. The longer-term increase in ideal heavy oil demand is driven by refinery investments defined out to 2015, with fuel oil demand decline having limited impact. Wood Mackenzie built the analysis based on publicly available refinery deep conversion investments which refiners have announced no farther than 2015.

<sup>&</sup>lt;sup>4</sup> Wood Mackenzie defines 'Ideal' capacity as the quantity of heavy crude oil which a refinery would ideally process, based on processing capability of a refinery's configuration. It is based on the crude oil characteristics assumed in the design of refining capacity. In actual operations, a refiner will optimize the crude slate based on the relative prices of various crude oils. Thus the operating crude oil slate might deviate from the design (or "ideal") crude slate.



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- 198 Global ideal demand is forecast to increase significantly between 2005 and 2020. As shown in Figure
- 199 6 below, the ideal capacity for refinery processing of heavy crude oil versus the change in the ideal
- 200 heavy crude oil demand for each of these regions.



Charts show regional heavy crude supply and ideal refining demand

North America represents U.S., Canada and Mexico where the supply gap is created by significant decline in Mexican heavy grades (i.e., Maya) and moderate heavy oil processing capacity additions particularly within PADD II. The ideal demand change relative to total heavy crude supply change results in a significant gap of nearly 2,000 kbd. This gap is expected to have strong competition from Asia Pacific as massive downstream investments within this high-growth region lead the ideal heavy oil demand increase. The increased pace of investments within the region follow significant participation from National Oil Companies in maximizing distillate production through additional upgrading of heavy barrels. The majority of investments are concentrated in China and India with an estimated 2,000 kbd and 1,000 kbd of new capacity additions, respectively, as shown in Figure 7. The chart shows only the refinery investments Wood Mackenzie expects to be on-line by 2015. If additional refining capacity is added beyond 2015, Wood Mackenzie assumes such capacity would be designed based on the expected Pacific Basin crude supply potentially available at that time. While North America and Asia see a growth in the regional supply gap, growth in Middle East heavy crude oil production far surpasses the increase in regional heavy crude demand; thus the surplus of heavy crude oil supply from the Middle East is expected to grow.





**Figure 7: Asia Pacific Heavy Crude Oil Demand Change per country (2005-2020)** 

Price differentials between heavy and light crude oil grades are the mechanism by which heavy crude oil supply balances with heavy crude oil demand in the refining sector. As the global ideal demand change for heavy crude oil is expected to surpass supply we expect the light – heavy differential (the price difference between light crude oil and heavy crude oil market markers) to remain narrow and thus play a key role in Canadian crude oil netbacks.

#### **BENEFITS OF A "WEST COAST" EXPORT CAPACITY OPTION**

A West Coast export capacity option would offer Canadian producers sufficient market access to overcome the shortfall shown previously in Figure 5. As seen in Figure 8, an increase of 525 kbd in West Coast transportation capacity provides adequate market access for a number of years with the potential to service both the light and heavy Canadian crude oil productions. Wood Mackenzie does not consider a 'feedback' effect that additional market access might spur incremental WCSB crude oil production so our crude disposition outlook does not anticipate any additional oil sands production investments to those shown previously in Figure 5. The additional pipeline capacity grants heavy crude oil export volumes to flow until about 2018 when yet again the supply profile exceeds access to the key demand centres.





**Figure 8: Western Canada Heavy Crude Oil Disposition (2010-2025) – with a West Coast Pipeline** 

Increasing West Coast market access could provide opportunity to increase Canada's export of both light and heavy crude oil production. From a heavy crude oil perspective the access would provide producers with the option to export large volumes of oil sands diluted by condensate ('Dilbit') or synthetic crude oil ('Synbit') to the growing Asia Pacific crude oil demand centres, such as China. 234 Figure 9 compares the Pacific Basin's complex (e.g., fluid catalytic conversion, hydrockrackers) and 235 deep conversion (*i.e.*, cokers) configurations to those of the U.S markets. On a regional basis the U.S is far more complex, specifically within PADDs III and V, as these refining centres hold the highest conversion capacity ratios. However, China's refinery configuration is the most complex amongst countries in Asia holding significant coking and cracking capacity relative to total crude distillation capacity. Other countries, such as Japan and Singapore, have historically geared their refining investments to cracking configurations to support distillate and petrochemical's feedstock production, thus for these countries lighter Canadian SCO barrels would be an attractive crude supply.





**Figure 9: Regional Refinery Configuration** 

The value created by increasing West Coast market access intrinsically depends on the logistic costs and other key factors described within the methodology (see Appendix 1). Figure 10 compares transportation rates from Edmonton to key demand refining centres within the U.S and within Asia Pacific. From Kitimat marine transport rates vary by distance travelled, class (size) of the tanker, and supply-demand balance of tanker hauling capacity. Spot rates for marine transport are fairly volatile so for simplicity we average tanker rates for 2005-09 assuming that Pacific Basin refiners have long-term charter contracts on the class of vessel used to ship volumes received from the Canadian West Coast. The resulting costs to the Asia Pacific market compete directly with the estimated pipeline tariffs to U.S refining markets.







Diluent is a major issue affecting the transportation of heavy crude. Many heavy crude oils, and especially bitumen, must be blended with condensate to form "Dilbit", or synthetic crude to create "Synbit", or a mixture of both to create "DilSynbit", to meet density and viscosity requirements for 254 pipeline transportation.<sup>5</sup> The projected Canadian oil sands production profile implies additional diluent could be required for blending for transportation. Canada produces about 400 kbd of condensate used as of today, but the increase in oil sands production would potentially exceed the current supply of WCSB diluent. Thus Canada could need to supplement local condensate production with international diluent imports. In addition, the blending of bitumen with lighter feedstock can create a liquid loosely analogous to a heavy-sour conventional crude.

Condensate, SCO, and NGLs are not all equal in their applicability for blending. Sour synthetics, butane and sour condensates are less acceptable than sweet condensates or light sweet synthetics. If condensate production in Canada is near its peak as natural gas in the region is increasingly sourced from unconventional and dry gas sources, condensate in Alberta attracts a premium to market prices. This reduces the value of bitumen, net of blending, by the bitumen producer.

Wood Mackenzie assessed the condensate supply requirement outlook for bitumen dilution as shown in Figure 11. Total condensate supply for Canada depicts a gradual decline in local production out to 2020. Rail import volumes, typically filling in the step changes in supply, are expected to be cleared from the market as volumes sourced from Enbridge's Southern Lights (originating in Chicago to Edmonton) in 2010 are projected to be a lower cost option for producers. Thus for this analysis Wood Mackenzie anticipates Southern Lights running at full capacity and gradually reducing rail imports. The condensate volumes on Southern Lights are expected to satisfy the region's condensate demand until approximately 2015 when additional condensate import volumes are needed to continue to support the export of oil sands bitumen via pipeline.

<sup>&</sup>lt;sup>5</sup> For the purposes of this report, Wood Mackenzie uses the term "condensate" to refer to any oil sands diluent blending material that broadly has the same blending characteristics (e.g., gravity, viscosity, sulfur) as condensate associated with conventional WCSB natural gas production.



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**Figure 11: Condensate Supply for Bitumen Dilution** 

The demand for additional condensate volumes supports a condensate import line to Edmonton that could be provided by the condensate import return pipeline (originating in Kitimat, British Columbia) Enbridge is proposing as part of the Northern Gateway solution. Sourcing condensate from the Pacific Basin requires consideration to the comparative value-in-use of condensate in its various end uses. Currently condensate demand in the Pacific Basin stems from petrochemical feedstock, as well as atmospheric distillation in Asia Pacific refineries. The relative value Canadian producers place on condensate for dilution purposes would compete against Asian petrochemical and refinery facilities. Prior analysis by Wood Mackenzie shows there is a sufficient condensate volume on a global basis to supply Canadian oil sands demand for the foreseeable future.

#### **Netbacks by Market**

Wood Mackenzie analyzed the potential impact that a West Coast crude export capacity option (based on Enbridge's Northern Gateway proposal) has on Canadian producers by assessing the value added to producers under the scenario of having this export option and the value loss created by its absence. The analysis was constructed for both the light ("SCO") and heavy ("Dilbit" and "Synbit") crude oils as the pipeline project is considered to be a mixed pipeline capable of transporting both crude profiles. The netbacks were constructed by analyzing cracking and coking configurations in both the U.S. 289 (PADDs II, III, IV and V individually) and selected Asian markets (e.g., China, Singapore) on the basis of Wood Mackenzie's December 2010 Product Market service prices and margins for the time period 2010 to 2025).

Our netback estimates for heavy crude oil do not consider PADD V or Japan as potential markets. California state legislation commonly referred to as "AB32" requires a 10% reduction in carbon intensity of fuel supplied within California by 2020. Draft regulations propose a carbon intensity for



both crude oils, as well as, the Low Carbon Fuel Standard (LCFS). Wood Mackenzie presumes the intent of these regulations is, in part, to discourage the use of Canadian oil sands within California refiners. In addition, Canadian heavy crude oil is not considered to flow to Japan as the configuration does not have the appropriate refinery configuration to process such heavy feedstocks. However, SCO is considered as an attractive crude oil for Japanese refiners.

#### **Dilbit and Synbit Netbacks by Market**

The netback calculation is the valuation of Canadian crude relative to its competing crude in each relevant refining market. For example, we use Cold Lake as a proxy for diluted bitumen and it competes with Arab Heavy, which for simplicity we assume is the marginal heavy crude in each refining market. These crudes are referenced to WTI by differential.

An example of this result for the year 2020 is found below in Figure 12. The net back is then WTI, less the refining market differential, less the logistic cost to move the crude from Edmonton to the refining market. The netback in Edmonton is the USGC refining value less the cost of transportation and any difference in refinery processing costs between the Canadian heavy crude oil and the alternative heavy crude oil it competes against. For example, if the USGC refining value of Cold Lake is C\$80.75/bbl, then the netback in Edmonton would be the USGC value, less transportation (C\$6.80/bbl), less the difference in refinery operating costs relative to Arab Heavy, the competing heavy crude oil, (C\$1.00). Thus the C\$80.75/bbl netbacks to C\$72.95/bbl in Edmonton.

**Figure 12: Crude Oil Netback Calculation Example - Cold Lake** 



Figure 13, shows estimated netbacks to Canadian producers for both Dilbit and Synbit reflecting the ranking to which bitumen blend would maximize value to Canadian producers from each respective demand centre. The price of a crude (or class of crudes) is determined by the 'marginal configuration', which is the value of the crude in the configuration in which the last barrel of that crude is processed. This marginal configuration for that last barrel across all refining centres sets the market price for crude at the refinery gate. The netback value to a producer is determined by this refinery gate price less transportation costs to reach that refining centre. The results below do not imply that crude oil from Canada would only flow to the market offering the single highest netback. In reality, crude oil is likely to flow in every direction to the more complex refineries in each market.





One of the implications illustrated by Figure 13 is that U.S. markets continue to offer attractive netbacks to producers, and Asian markets offer competitive netbacks to place additional barrels beyond PADD IV and PADD II. In particular, PADD IV is the most attractive market for Dilbit and Synbit as netbacks to this market are driven by lower logistics costs and competitive price premiums to USGC product prices relative to other U.S markets. On a Synbit basis, PADD II follows as the next most attractive region because despite having a higher refining value driven by product prices set by cost of imports – usually PADD III spot prices plus a premium that is at a minimum the variable toll on the marginal product pipeline. However, more expensive logistic costs compared to PADD IV decreases PADD II's resulting netback. Lower product prices and the higher transportation costs explain PADD III netbacks. PADD III holds lower product prices (see Figure 27 in Appendix 1)as it is the main hub within North America where supply exceeds local demand relative to other U.S refining 332 regions.



A West Coast transportation option suggests China would offer the highest netback amongst the potential Asian markets. Canadian producers may be indifferent from sending Synbit to either PADD II or China given the small differences in the resulting netbacks. The drivers supporting the Chinese values are both the Chinese distillate prices as well as the yield from Synbit. Asia holds a higher premium in diesel to the USGC prices when compared to PADD II. The advantaged distillate yield is the result of each region's configuration. Chinese refineries are dominated by coking/hydrocracking configurations for maximum distillate yield, while PADD II refineries predominantly are configured 340 around coking/Fluid Catalytic Cracking  $(i.e. FCC)$  for maximum gasoline yield.

Price differentials and product yields also are crucial to describing the Dilbit netbacks between China, PADD III and Singapore. The advantage of China is effectively the strength in the higher distillate yield cut supported by higher prices versus the gasoline yield obtained in PADD III. However, this advantage is not strong enough for Singapore as the price premium is not sufficient to outweigh the gasoline advantage generated from processing Dilbit in PADD III. Chinese and Singapore netbacks mainly are led by market price differentials where Singapore is expected to maintain lower prices as it is the key Asian regional export centre satisfying the Chinese market.

#### **Heavy Crude Disposition With a West Coast Pipeline**

Figure 14 describes the potential disposition of Canadian heavy crude to the main demand centres with a West Coast pipeline option in service. Wood Mackenzie allocates WCSB production to the demand centres following the netback merit order described in Figure 13. The analysis was constructed for 2018 as the base year additional production reaches an access shortfall. Total heavy crude disposition reflects the total WCSB production profile through the available export pipeline capacity to the key demand centres shown in Figure 8.



**Figure 14: Canadian Heavy Oil Demand Curve – With a West Coast Pipeline Option** 



354 Part of the reason for crude earning a higher netback in the Pacific Basin (e.g., China) over the Mid-355 Continent (i.e., PADD II) of the U.S. is driven by Saudi Arabia historically pricing cargoes heading to Asia at a premium to cargoes heading to Europe or North America. Saudi Aramco are able to do this because they contractually restrict resale or redirection of cargoes loaded in Saudi Arabia through a "destination clause" in the contract. This pricing premium is a function more of pricing crude in Asia at what the market will bear rather than an adjustment for transportation differentials. Although excluded from this analysis, if the Trans Mountain expansion volume (400 kbd) were added, the "PADD III" tranche on the far right side of Figure 14 would be absorbed by additional westbound transportation capacity from the Trans Mountain expansion, increasing the ability of Canadian oil producers to access the Pacific Basin crude oil market.

Wood Mackenzie assumes there could be a preference for Dilbit to meet North America heavy crude oil demand as it has the flexibility to recycle diluent. Thus Synbit volumes could be available for export to the preferred markets. As previously mentioned U.S. netbacks to PADD IV are predominantly higher than those to the Asian market on both a Synbit and Dilbit basis, with minor differences that would make Canadian producers indifferent to placing volumes in either market. As Synbit netbacks are higher than Dilbit's we assume Synbit volumes are allocated first to fill the PADD IV demand because this region dominates the netbacks amongst the U.S. markets. Given that the total Synbit production exceeds demand in PADD IV, the remaining Synbit production would then flow to the next market offering the next highest netback. The partial differences between PADD II and China's Synbit netbacks suggest Alberta producers, having the option to export volumes to Asia, would prefer to place the remaining Synbit volumes in to the Chinese market.

The additional WCSB oil sands production (diluted with condensate once SCO allocated to blending is exhausted) would flow in order of netback preference to PADD II, China and PADD III, until Dilbit demand is exhausted via the corresponding pipeline capacities. Thus the potential West Coast pipeline would be filled to maximum capacity balanced by the flow of Synbit to China (~410 kbd) and Dilbit to China (~115 kbd). Thus a West Coast pipeline offers Canadian producers the potential to optimize exports to alternate markets while aiming to maximize total value of netbacks.

#### **Heavy Crude Disposition Without West Coast Access**

The heavy crude oil disposition without a West Coast Pipeline is described in Figure 15, through each market's demand capacity and corresponding netback. In the absence of additional West Coast pipeline capacity, access to the Asia Pacific market is constrained which implies that both Synbit and Dilbit productions must be allocated within available U.S. markets. Synbit thus flows to first PADD IV and PADD II as these present higher netbacks and are able to absorb total Synbit supply.





**Figure 15: Canadian Heavy Oil Demand Curve – Without a West Coast Pipeline Option** 

The price of a crude (or class of crudes) is determined by the value of the crude in the configuration in which the last barrel of that crude is processed, i.e., the marginal configuration. In the case of Canadian heavy crude oil, without sufficient access to coking refining markets, the marginal configuration is a cracking refinery which sits either in PADD II or PADD IV. Absent a west coast export capacity option, heavy crude oil volumes that otherwise would have been exported to China must now find a home within the U.S markets offering the best available netback. After accessible coking configurations have been filled, heavy crude oil must flow to cracking configurations until supply is exhausted. Diluted bitumen (Synbit or Dilbit) flows first to the coking configurations in PADDs IV, II, and III, until coking demand within these markets is satisfied. The remaining heavy crude oil volumes must then be allocated in cracking configurations in PADD IV or II. Wood Mackenzie assumes that PADD II is the natural market where these volumes would be exported given the proximity (low logistics costs) and the capacity of the refining market which is able to absorb the remaining supply.

As a result of the heavy crude oil disposition without a West Coast solution, Canadian producers would increase volumes to PADD II cracking configurations implying a significant value loss relative to Asian market alternatives. The total value loss is defined through the difference in netbacks of exporting heavy crude oil volumes to China's coking/hydrocracking configuration and instead exporting to a PADD II cracking configuration. The difference in these respective netbacks is approximately US\$8/bbl. If this difference were limited to the heavy crude oil flowing in to the cracking configuration (~325 kbd) – this discount would represent a loss of nearly US\$1 billion per year. However, in a competitive market the value of crude oil in marginal configuration sets the price for all barrels of similar crude oils, the potential value loss of a US\$8/bbl discount across every barrel of Canadian heavy crude oil supply (just over 2,300 kbd in 2018) could approach US\$6 -7 billion per year.



**Synthetic Crude Oil Netbacks by Market** 

- Figure 16, shows estimated netbacks from various markets to Canadian producers for SCO ranked
- from highest to lowest for the year 2016. The results below do not imply that crude oil from Canada
- would only flow to the market offering the single highest netback.



U.S. markets potentially would offer the highest SCO netbacks to Canadian producers. The results are driven by both regional product price structure and the product yield resulting from SCO refined through the typical regional cracking configuration. The U.S. advantage over Asia reflects the higher gasoline yield from processing SCO in a U.S configuration over the higher distillate yield produced from processing SCO in an Asian configuration. The distillate yield and prices in Asia are not sufficient to deliver higher refining values. Thus U.S. markets, also supported by lower logistic costs, result in higher netbacks relative to those obtained from Asia. However, the small difference between the PADD III and the Japan netback might lead Canadian producers to conclude they are indifferent to exporting SCO volumes to either of these locations.

Within the U.S., the market advantage of the different refining centres is led by logistics and price premium to USGC. Crude oil going all the way to PADD III versus being delivered in PADD IV or PADD V would pay an incremental tariff while also processed in a relatively more competitive product market region (with lower relative product prices) resulting in lower netbacks to Alberta producers, assuming the crude is processed in the same configuration.



**Light Crude Disposition With and Without A West Coast Pipeline** 

The disposition of SCO with a West Coast pipeline is illustrated in Figure 17. Wood Mackenzie allocates the supply to demand centres following the netback merit order described in Figure 16. For this analysis Wood Mackenzie considers the North American West Coast to include volumes on Trans Mountain.



**Figure 17: Canadian Light-Sweet Crude Oil Demand Curve – without a West Coast Pipeline Option** 

In the absence of a West Coast pipeline option, Canadian producers would maximize the value on SCO supply following the netback preference order, where each market's demand is filled until supply is exhausted or logistic capacity to each market is filled. The absence of this West Coast transportation option suggests exports would be restrained to a single region (U.S.). Refineries with FCC cracking units typically face a technical limit on the capability to process SCO due to the volume of light ends produced in the FCC due to vacuum gasoil (VGO) properties in SCO. Without a West Coast pipeline it is possible for there to be more SCO available than accessible US refineries could process. In this case there could be discounts to place the last barrel of SCO in the US refining system. Because the economic value of this discount is so specific to the configuration and operating environment of each refinery, we do not attempt to estimate its magnitude in this report.

The disposition of SCO, considering a West Coast option as shown in Figure 18, follows the same netback production allocation by preference analysis. A West Coast pipeline option creates value to Canadian producers as it allows for the diversification of export destinations, which mitigates the potential processing capability limits mentioned above. In addition, a West Coast option offers Canadian producers the option that if incremental upgrading capacity comes online there is sufficient capacity to export the incremental supply to the growing Pacific market.





**Figure 18: Canadian Light-Sweet Crude Oil Demand Curve – with a West Coast Pipeline Option** 

#### **Non-fungible Character of Crudes**

The disposition of crude volumes through a West Coast pipeline option depends on the fungible character of crudes. Wood Mackenzie refers to this concept as the capability of crude oil to be allocated in any given market across multiple configurations without losing value relative to its preferred configuration. SCO is a fungible crude as it can be processed in any given market maintaining its implicit value based on the market's nature of price and location. SCO netbacks maintain their competitive nature across the array of markets despite the potential FCC technical limits mentioned previously. This is not the case for WCSB heavy crude oil volumes, as these volumes, if not valued into the appropriate configuration (coking), possibly would result in significant discounts, which lower netbacks.



456 Figure 19 illustrates the effect of the non-fungible character of these crude types through the 457 comparison of crude allocations by demand centre and netback preference without a West Coast



pipeline option. Driven by Wood Mackenzie's WCSB production forecast, the disposition of heavy 459 crude oil demand without access to the Pacific Basin implies a loss of nearly \$8/bbl.<sup>6</sup> Dilbit volumes not reaching coking configurations in Asia, once all coking configurations' demand in U.S have been filled, must seek disposition in to cracking configurations. The result is lower refining values because volumes placed in these configurations cannot maximize value without the deep conversion component. This discount would apply not to only the last tranche of heavy crude oil, but to every Canadian heavy crude oil barrel. The \$8/bbl discount would average over C\$8 billion per year (\$8/bbl \* 2,740 kbd \* 365 days) in lost revenue to Canadian oil producers over the 2017 to 2025 time period.

The allocation of crude oil through a West Coast pipeline option is equivalent on a heavy or light barrel, as one barrel of light crude displaces a barrel of heavy crude. Thus given the greater value loss in heavy versus light allocation opportunities, and considering the increasing production of Canadian oil sands, a West Coast pipeline likely would prefer the disposition of heavy crude oil barrels.

#### **CONCLUSIONS**

Wood Mackenzie estimates the magnitude by which a West Coast pipeline would lead to higher netbacks for all Canadian oil sands producers. The outlook of global heavy crude oil supply suggests growth would be concentrated in the Middle East and Canada. Meanwhile heavy crude oil demand growth would be concentrated in North America and emerging Asia refining centres. The Canadian supply profile suggests producers are likely to require additional market access to export incremental volumes of heavy crude oil to key demand centres. Given a current lack of access to key demand centres and the lengthy lead time required to execute a pipeline project and the projected growth in supply, the timing of a West Coast export capacity option is critical.

The resulting netback to producers is structured by refining market configurations, regional product prices and logistic costs. Wood Mackenzie assessed the potential impact of adding West Coast tidewater access on Alberta crude oil producers' netbacks, considering a pipeline connecting Edmonton to Kitimat with a return condensate pipeline.

<sup>&</sup>lt;sup>6</sup> A recent study by the School of Public Policy at the University of Calgary (M. Moore, "Catching the Brass Ring: Oil Market Diversification Potential for Canada", SPP Research Papers, Vol 4:16, 2011) estimates the discount from market access bottlenecks is over \$10/bbl. Providing better access to markets would increase Canadian GDP by over \$130 billion between 2016 and 2030.



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Comparisons of the Synbit and Dilbit netbacks with and without producers having access to markets connected through a West Coast pipeline option indicate an \$8 per barrel swing. Fundamental factors suggest diluted bitumen receives higher netbacks in PADDs IV and II markets on both a Synbit and Dilbit basis relative to China (and Singapore). Of the Asian markets, China would be the most attractive for the disposition of heavy Canadian crude oils. The projected price for gasoline and diesel in Asia are expected to rise in this region as emerging deficits support the increase in oil product prices. This would support Synbit and Dilbit to have a sustainable netback in Asia competitive against that of PADD II and PADD III, respectively. Our assessment of producers not having access to the Asian markets through a West Coast tidewater option suggests producers are likely to lose about \$8/bbl (lost revenue of C\$8 billion per year for 2017 to 2025) by having to place marginal heavy crude oil volumes in to cracking configurations in PADD II.

For light crude oil, SCO netbacks from the U.S markets are higher than those of Asia. However netbacks are not materially different among PADD III, Japan, or China. A lack of access through a West Coast pipeline decreases producer's options of diversifying export opportunities and maximizing value to refining centres in case additional upgrading capacity increases production.

Finally, the non-fungible market nature of heavy crude oils makes it imperative that the West Coast solution support the disposition of Dilbit and Synbit. Thus having a westbound outlet for Canadian crude, especially for these less fungible crudes, provide a valuable alternate disposition.



## **APPENDIX 1: METHODOLOGY**

Our approach to the netback analysis derives from a series of fundamentals that frame a crude oil's value to producers. Our analysis begins by comparing a crudes quality against its regional competitive crude marker on the basis of product yields, further integrating this analysis with our outlook for refined product prices in each market and also the "supply/demand" balance for the particular crude oil type as shown in **Figure 21**. These elements compose the fundamentals to valuing a crude oil's netback to producers.



#### **Crude Assay Characteristics**

Crude oils have a variety of qualities and characteristics which impact their desirability for processing in a refinery. A refiner's preference for which crude oil characteristics are best suited for any specific refinery is a function of the configuration (e.g., process units, capacities, operating envelopes), product demand in their respective market, and finished product quality specifications. Thus refiners do not evaluate a crude oil against the universe of available crudes. Rather they group crudes in to baskets with similar characteristics (e.g., heavy vs. light; sour vs. sweet) and look for the crude that is most economic (*i.e.*, results in a higher variable cash margin) within a class.

Below we look at an example of how refiners might compare typical Canadian crudes to their respective alternatives. There are a myriad of Canadian crudes which flow in to a variety of markets. For simplicity (and brevity) we compare SCO as an example of a light-sweet crude and Cold Lake as an example of heavy-sour crude. Both of these crude types are in production in Canada today and are projected to remain a significant share of the future in the production profile shown above.

Synthetic Crude Oil API gravity and sulphur (by weight percent) are often used to estimate crude oil values, but they are only proxies. To be precise about quality, far more detailed assays measuring percentages of various product "cuts", their metals contents, and a variety of other chemical properties that are important to refiners also must be used. **Figure 22** shows the API gravity, sulphur, and basic product cuts for SCO and two representative crudes that are refined in PADD II and PADD III (WTI) and the Pacific Basin (Arab Light).





**Figure 22: Light Crude Oil Characteristics** 

Heavy crudes (those with API gravity less than 28°) tend to have a narrower market than the light crudes described above. Figure 23 shows heavy crudes tend to have lower APIs (higher specific gravity) than light crudes because of larger residual cuts. This cut does not easily convert to finished petroleum products so additional processing units (e.g., coking) found in more complex refineries are needed to transform the crude oil barrel to better match the market demand product barrel. In addition, heavy crudes tend to be higher in sulphur which requires more or larger units (e.g., hydrotreating, sulphur recovery) than found in smaller, simpler refineries to achieve the product quality specification requirements on products, such as sulphur-free fuels. Similar to light crudes there are a variety of heavy crudes in the global oil market. The figure below focuses on Cold Lake (Canada), Maya (Mexico), and Arab Heavy (Saudi Arabia) as representative heavy crudes refined in North America and Asia.







## **Refining Value Analysis**

A review of historical trends between relative refining value for competing crudes and actual prices achieved provides an understanding of marginal configurations which set crude price differentials and the potential impact of any other specific crude market dynamics affecting differentials. Analysis of the drivers behind the marginal configurations enables us to forecast relative refining values and hence develop crude price differentials, based on our regional price forecasts for refined products, along with the capability to review the appropriateness of the marginal refining configuration in the context of the "supply/demand" balance aspects.



**Figure 24: Crude Valuation Analysis Process** 

Refining Value Analysis, which is the value of products produced from a given crude oil *(i.e.*, GPW or Gross Product Worth), is central to our approach. Individual refiners choose crudes providing the highest margin for their particular configuration. This concept generalizes to the industry as a whole in each refining region to illustrate key refining drivers behind crude price differentials.

Price differentials between alternative crude types  $(e.g.,$  "heavy" crude oils) are crucial to understanding refining economics both historically and in the future. Light/heavy crude price differentials typically reflect the combined influences of underlying quality differences and relative supply/demand 'tightness'. Figure 25 below shows the historical pricing relationship between WTI typical US light crude) and WTS (a typical US medium/heavy crude).





**Figure 25: Refining Value Relative to Market Price (WTS – WTI)** 

The top (red) line shows the relative 'refining value' of the two crude oils in a typical USGC cracking refinery, which represents the reduced value of Refined Petroleum Products achieved by processing WTS instead of WTI. The lower (blue) line shows the actual market price differential (*i.e.*, the WTS discount to WTI). The chart illustrates how the two lines only occasionally coincide and reflects the effective 'quality differential' between the two crudes. WTS typically trades at a discount to its underlying quality differential so the quality differential historically has provided a price 'ceiling' to WTS. Periodic substantial discounts below the underlying quality differential correspond to periods of oversupply of sour crudes, so the "supply/demand" balance reflects the supply of crude oil and the capability of the local refining system to accommodate that supply. In periods of "oversupply", the crude oil pricing mechanism often shifts to that of a less complex configuration, as the heavy crude must be priced at a further discount to penetrate a different (less appropriate) tranche of processing capacity.

#### **Netback Calculation**

The key to the netback analysis is a solid understanding of how refiners value various crude oils across different markets, with those refining values subsequently netted back to a producer in Alberta by subtracting the appropriate transportation costs. Figure 26 below illustrates how refiners would make these valuations for Dilbit (bitumen diluted with condensate for transportation purposes).





**Figure 26: Valuing an Alternative to a Marker Crude Oil** 

We value non-fungible crudes relative to their appropriate benchmark crude (crude marker) in the open market. In order to switch crudes, a refiner must be indifferent between crudes on a variable cost basis. Crudes tend to have different Gross Product Worth (GPW) and operating costs within a given configuration. If the GPW is lower or the operating cost is higher, a refiner would demand a discount from a competing crude oil. The market-clearing netback value of a crude oil is determined by the discount required to place the marginal barrel in to the least valuable configuration across each potential market less the transportation cost from Alberta to that market clearing refinery location and configuration. For the U.S. this is typically WTI as a proxy for light crude and Maya or Mars for heavy crudes. In Asia the light crude tends to be represented by Arab Light and heavy crudes by Arab Heavy. In this analysis we compare the USGC and Singapore light-heavy differentials using WTI (USGC) and Arab Light (Singapore) relative to Cold Lake, under the assumption a west coast option exists to move heavy Canadian crude to Singapore. The respective GPW estimates are determined by multiplying the crude's yields times the regional product prices (shown in Figure 27) to determine the crudes' resulting refinery value that generates an equivalent margin to the selected crude marker.





**Figure 27: Regional comparative prices to USGC – U.S. (PADDs II, III, IV, V), and Asia (China, Singapore)**

We repeat this analysis for each relevant market within the U.S and Asia for Dilbit, Synbit, and SCO. The netback calculation is then the combination of the analysis of Figure 26 and Figure 28. An example of this result for the year 2020 is found below in Figure 28. The net back is then WTI, less the refining market differential, less the logistic cost to move the crude from Edmonton to the refining market.



**Figure 28: Illustrative example of Crude Netback Calculation - Cold Lake in 2020** 



## **APPENDIX 2: DATA TABLES FOR FIGURES**

**Table 1: Map West Coast Pipeline proposed route** 





#### **Table 3: Regional Heavy Crude Oil Production Change 2010 – 2025 (kbd)**



#### **Table 4: Heavy Crude Oil Production 2010 (kbd)**







#### **Table 5: Western Canada Heavy Crude Oil Disposition (kbd)**

**Table 6: Heavy Crude Oil Supply Change vs. Heavy Crude Oil Ideal Demand Change – North America, Middle East, and Asia Pacific (2005-2020) (Mbd)** 

	2005	2006	2007	2008	2009	2010	201	2012	2013	2014	2015	2016	2017	2018	2019	2020
<b>North America</b>																
Regional supply changes -		$-0.2$	$-0.4$	$-0.8$	$-1.0$	$-1.1$	$-1.2$	$-1.4$	$-1.3$	$-1.4$	$-1.3$	$-1.3$	$-1.3$	$-1.2$	$-1.1$	-1.1
Regional demand changes -		$-0.2$	$-0.5$	$-0.7$	$-0.8$	$-0.9$	$-0.6$	$-0.2$	0.2	0.5	0.9	0.9	0.9	0.9	0.9	0.9
<b>Middle East</b>																
Regional supply		0.2	0.1	0.2	0.0	0.1	0.2	0.3	0.4	1.2		2.2	2.7	2.8	2.8	3.0
Regional demand		0.2	0.4	0.6	0.5	0.3	0.5	0.6	0.8	0.9	l. 1					1.1
Asia Pacific																
Regional supply changes -	-	$-0.2$	$-0.4$	$-0.8$	$-1.0$	$-1.1$	$-1.2$	$-1.4$	1.3 $-1$	$-1.4$	$-1.3$	$-1.3$	$-1.3$	$-1.2$	$-1.1$	-1.1
Regional demand changes -		$-0.2$	$-0.5$	$-0.7$	$-0.8$	$-0.9$	$-0.6$	$-0.2$	0.2	0.5	0.9	0.9	0.9	0.9	0.9	0.9

**Table 7: Asia Pacific Heavy Crude Oil Demand Change per country (2005-2020) (Mbd)** 







## **Table 8: Western Canada Heavy Crude Oil Disposition with a West Coast Pipeline (kbd)**

#### **Table 9: Regional Refinery Configuration Structures (2010)**

	COK	<b>FCC</b>	<b>HCK</b>
<b>USGC</b>	25%	37%	26%
<b>PADD II</b>	19%	35%	33%
<b>PADD V</b>	31%	44%	19%
Japan	2%	20%	17%
China	19%	21%	18%
Singapore	$0\%$	$0\%$	5%

**Table 11: Condensate Supply for Bitumen Dilution (kbd)** 







#### **Table 12: Dilbit, Synbit Edmonton Netbacks (2020)**

#### **Table 13.0 Canadian Heavy Oil Demand Curve – With a West Coast Pipeline Option**



#### **Table 14.0 Canadian Heavy Oil Demand Curve – Without a West Coast Pipeline Option**



#### **Table 15.0 2016 SCO Edmonton Netbacks**



#### **Table 16.0 Canadian Light-Sweet Crude Oil Demand without a West Coast Pipeline Option**





**Table 17.0 2020 Canadian Light-Sweet Crude Oil Demand Curve – with Northern Gateway** 



#### **Table 18.0 Heavy and Light Crude Demand – Without a West Coast Pipeline**





## **APPENDIX 3: GLOSSARY OF TERMS**

**Compound Annual Growth Rate** (CAGR): The year-over-year growth rate of a data series over a specified period of time. It is calculated by taking the nth root of the total percentage growth rate, where  $n$  is the number of years in the period being considered.

**Fungible crudes**: Refers to crudes which maintain their refining values when processed in any given refinery configuration. (i.e., light crudes). The resulting gross product worth remains relatively unchanged as it is able to yield similar productions maintaining their high product value. Non-fungible crudes, are heavy crudes which loose their refining values when processed through refinery configurations (i.e., cracking) different than their corresponding deep conversion configurations (i.e., coking). Processing heavy crudes through a cracking configuration results in significantly lower gross product worth. This configuration has higher yield of fuel oil and limits the yield of higher valued products.

**Gross Product Worth**: Revenue of a refinery determined by the yield of each product multiplied by its regional product price.

**Ideal capacity**: Refers to the quantity of heavy crude oil which the refining industry would ideally process, based on its combined processing capability. It is based on the structural refinery demand for vacuum residue material, and an assumed vacuum residue yield on crude of 30% volume.

**Marginal configuration**: represents the refinery configuration that sets the value of the crude as it is the configuration in which the last barrel of that crude is processed.

**Petroleum Administration for Defense District** (PADD): originally developed for fuel allocation, PADD's are used to characterize US refining on a regional basis. The regions are used by the U.S. Department of Energy for planning purposes. The result is a geographic aggregation of the 50 States and the District of Columbia into five Districts, with PADD I further split into three sub districts

**Refining values**: The value of a crude oil, which considering operational expenses, generates an equivalent margin relative to the regional crude marker.

**Unconventional grades**: refers to those heavy crude oils produced from diluted bitumen which require blending with condensates to form "Dilbit", or be processed through an Upgrader to form synthetic crude to create "Synbit", or are a mixture of both to create "DilSynbit" – all processes are required in order to meet density and viscosity requirements for pipeline transportation

**Unrisked oil sands projects**: considers production from all announced and ongoing oil sands projects reaching their full capacity of production with no binding constraints on the production profiles per crude type as long as projects' breakeven does not fall below minimum threshold relative to WTI price basis used to model each of the oil sands development projects

**Vacuum residue material**: refers to the heavy production generated from the vacuum process that is used to feed a refinery's deep conversion units or as the basic feedstock for fuel oil production.



## **APPENDIX 4: AUTHOR QUALIFICATIONS**

**Harold York** 

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 Ph.D., Economics, University of Virginia, Charlottesville, Virginia

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Dr. York is a Vice President in the Wood Mackenzie's Downstream Consulting Group in Houston, Texas. With almost 20 years of worldwide experience across the energy value chain, he has developed deep expertise in petroleum market economics. He specializes in strategy, commercial optimization, and market price-setting mechanisms. He provides support for clients along the transaction life-cycle; from forming the strategy leading to a transaction through closing and integrating assets in the acquiring corporate structure, as well as guidance on a variety of markets including hydrocarbon fuels, power generation, and emission allowances. Recently he has worked on understanding new North American gas shale plays, focusing on the Northeast, in order to develop strategic insights on the implications for supply-demand balances, LNG import requirements, and local pricing.

Dr. York participated in an effort to use microeconomics to explain the impact of refinery run decisions on wholesale prices in a lucrative U.S. market for a large refining and marketing client. This work resulted in defining specific price-setting mechanisms based on the relative length of the supplydemand balance for a variety of petroleum products. He subsequently led a valuation effort for possible asset acquisitions to capture value in their advantaged positions.

In addition, Dr. York has expertise in the valuation of exotic crude streams for a variety of international oil companies, and has conducted a strategic review and portfolio analysis for a national oil company that sought to measure its performance as a private company proxy. For a major North Sea operator, Dr. York assisted in assessing growth opportunity crude oils, in which the client had little marketing experience.

Prior to joining Wood Mackenzie, Dr. York was a consultant at CRA International (the former Charles River Associates). In prior work experiences he created a market analysis group in the Power Generation and Supply division of Reliant Energy. This team used market fundamentals to develop fuel and power market strategies and improves decision-making around the company's power generation and pipeline assets. Dr. York provided guidance on a variety of market trends around hydrocarbon fuels and power generation with a focus on the dynamic impacts on inter-fuel competition by LNG penetration, emission allowance pricing, and clean coal technologies.



Dr. York's experience leverages 10 years in strategic planning assignments in Exxon Mobil Corporation. He has held roles as the global expert on joint venture negotiation best practices, managing new business development downstream opportunities in Asia Pacific, and leading research teams on studies of the economic impact of large-scale oil investments on the economy of Russia. In addition to this, he has published papers on a wide variety of topics including LNG market dynamics, local and national economic impacts of large-scale petroleum projects, and international capital tax competition.

#### **Selected Engagement Experience**

#### **Litigation Support**

For several Canadian upstream companies prepared an expert report on the usefulness of the Alberta Clipper pipeline on clearing Canadian crude oil supply.

For an international oil & gas company, performed analysis around refinery production, imports, and pipeline flows of the New York Harbour gasoline market pertaining to MTBE liability claims.

For an international chemical company developed a forward view of natural gas and oil (including several intermediate products) prices to support asset valuations in litigation surround a potential acquisition.

#### **Strategy Development**

For an independent refiners in the US assessed the commercial viability of their US West Coast refining and marketing assets. Provided a competitor assessment that included a "feedback loop" incorporating potential actions by other competitors. The competitor assessment led to a highlevel valuation of the company's assets across a number of market evolution scenarios.

For a mid-size upstream company, analyzed the attractiveness of target refineries and estimated the cost of upgrading each to process significant volumes of oil sands bitumen. Provided transaction support for joint venture negotiations and for the eventual successful purchase of a refinery. Key work programs included structuring the post-acquisition integration plan, revising the client's existing supply and trading organization, and creating a new commercial organization.

For mid-size integrated oil company worked with a mid-stream business unit to develop strategies that were consistent with an overall corporate goal of achieving a position of industry leadership plan including budget, staffing, and performance metrics. Led an integrated team of consultants and client staff in the development of operating model alternatives that would bring new thinking to managing tradeoffs among reliability, capital and operating costs. Structured a series of action steps to subsequent implementation efforts.

#### **Performance Improvement and Organizational Effectiveness**

For a "mega-major" international oil company, developed a deep analysis of ways to use technology to reduce operating costs. Analyzed refining operations of key competitors including capital programs, organization structure and processes, and technology deployment models. Constructed a financial model of the firms' businesses to quantify the economic benefits realized through technology. Client is now applying the identified best practices to its network.



For a "mega-major" international oil company, facilitated identifying, developing, and implementing cross segment technology-related opportunities in support of corporate integrity agenda. The first stage of work focused on identifying technologies and practices having the greatest potential for sharing and transfer. The focus then shifted to how effective sharing can best take place including overcoming organizational barriers to sharing and transfer. Support took on a program management role involving tracking progress of each team, holding progress meetings with project teams, maintaining action logs, and creating consistent documentation describing each of the projects in status reports to the management.

#### **Natural Gas Markets**

For a large international petrochemical company, assessed the production of natural gas liquids (NGLs) for the US Gulf Coast region. Analysis was then applied to the expected rate of return on an ethylene feedstock conversion project under a range of ethane and naphtha prices. The review included an assessment of how many similar sized or Greenfield ethylene projects could be accommodated within the expected NGL production profile.

For a large international gas company, performed a due diligence review of an LNG regasification terminal in North America, including local market basis differentials, capital and operating costs, shipping, and netback pricing implications for the supplying liquefaction project. The review included assessing the strength and weaknesses of potential risk mitigation strategies.

For an international oil company assisted in identifying key issues, conducting analysis on supply, demand, prices, industry structure, and contracting norms, and formulating perspectives surrounding the most interesting global gas opportunities. Emphasis was on developing a comprehensive view of supply, demand, cost basis, and pricing outlook for natural gas by region. Reviewed political and economic factors that might impact the relative competitiveness of natural gas and competing fuels and incorporated those insights in the CRA World Gas Model.

For an integrated power company, analyzed economics of proposed regasification terminals along the U.S. East Coast and California including the basis differential between the target markets and the US Gulf Coast, development of the business model required to capture premium prices, and review of competitor projects. Financial valuation of the project on a stand-alone basis and discussion of its value as an enabler of other gas supply chain investment opportunities.

For a "mega-major" international oil company, completed a comprehensive review of gas opportunities for a large-scale gas development project in Asia. This review analyzed both power and non-power potentials for gas use in the local market, as well as LNG export opportunities in the region. Analysis included the cost in using gas from the project competing against incumbent power generation and for new builds competing against coal and oil fired power. Underlying this analysis was an initial review of industrial, commercial and residential power demand as related to GDP growth scenarios and an assessment of infrastructure requirements and costs to deliver gas to the appropriate demand centres.

For a "mega-major" international oil company, performed a review of an LNG project in the Atlantic Basin, including liquefaction, shipping and regasification stages of the value chain. Developed regional supply-demand balances and equilibrium price projections including the influence of spot markets on long term contracts. Identified strategies different competitors were employing and their strengths and weaknesses.



#### **Professional Experience**

#### 2009–Present Vice President, Wood Mackenzie

- Provided support to client interested in how downstream integration from refining to retail marketing might improve the financial liability of its business including potential reductions in earnings volatility
- Led strategic review of a refiner's current competitive position of its asset portfolio and potential benefits and risks to corporate sustainability

#### 2005–2009 Principal, CRA International

Dr. York specialized in strategy, commercial optimization, and market price-setting mechanisms. He provided support for clients along the transaction life-cycle; from forming the strategy leading to a transaction through closing and integrating assets in the acquiring corporate structure. He worked on understanding new North American gas shale plays, focusing on the Northeast, in order to develop strategic insights on the implications for supplydemand balances, LNG import requirements, and local pricing. Early in his time at CRA Dr. York led a strategic review of how refiners use technology to control operating costs.

#### 2003–2005 Director, Fuel Market Analysis, Reliant Energy, Incorporated

While at Reliant Energy, Dr. York created team-developing fuel market strategies around the company's power generation and pipeline assets. He improved discipline in decision-making by focusing on market fundamentals with an emphasis on natural gas. He also conducted analysis of market trends (e.g., supply/demand, price outlooks, inter-fuel competition, and environmental regulations) pertaining to natural gas, coal, oil, and emissions, and their impact on power generation dynamics.

#### 2001–2003 Engagement Manager, McKinsey & Company

Dr. York developed petroleum product price-setting mechanisms in and across multiple markets to support trading activities, asset optimization, and capital project consideration, and also formed asset-backed commercial strategies for merchant energy companies focusing on niche markets, origination, and cross-commodity plays. In addition, he assisted the board of directors of a major international oil company to improve corporate governance skills and also develop a CEO succession plan. As engagement manager, Dr. York's capacities included crude valuations and petroleum product market mechanisms; development of corporate and commercial strategy in multiple international markets; and asset valuations for mergers, acquisitions, and internal optimization. He also constructed numerous valuation models for exotic crude oils with national oil companies.

#### **Exxon Mobil Corporation**

#### 2000–2001 Senior Representative, Upstream Public Affairs

Dr. York's responsibilities as senior representative with Upstream Public Affairs included:

- Assessing risk in countries in Asia Pacific, Commonwealth of Independent States, and northern Africa,
- Establishing a public affairs function in new upstream company affiliates,
- Preparing briefing material for senior executive country visits.
- Serving as a media specialist on the Exxon Mobil Upstream Emergency Response Team

1998–2000 Advisor, Asia Pacific Regional Planning Centre



As an advisor at the Asia Pacific Regional Planning Centre, Dr. York managed transition issues in the merger of Exxon and Mobil, maintaining direct collaboration with operating lines. He also performed risk-assessments deferring investments over a five-year period, saving the company \$15–20 million. He was the project manager of project evaluations and executions in India, Indonesia, Taiwan, and Thailand. Other responsibilities in this position included:

- Authoring Exxon's worldwide "best practices" for joint venture negotiating,
- Valuing assets in Hong Kong, Philippines, South Korea, and Vietnam,
- Formulating a downstream entry strategy for Indonesia,
- Evaluating natural gas contracts for Exxon Chemicals Complex in Singapore
- Managing analysts performing business development and energy forecasting of Southeast Asian countries.

#### 1994–1998 Senior Analyst, Corporate Planning—International

As a senior analyst, he provided energy forecasting for China, the former Soviet Union, and Latin America. He was the Exxon representative to the European Union Directorate Group X2, which is the group that estimates the economic impacts of global climate change policies on the EU. Dr. York led research teams that studied the economic impact of large-scale oil investments on the economy of Russia. The studies were joint efforts with a team from the Russian Academy of Sciences headed by Dr. Alexander Arbatov, an economic advisor to every Soviet premier since the late–1960s. During this project he also worked with the energy, finance, and trade ministries in the Russian Federation government. A result of this research was an article printed in the June 1998 edition of *Oil and Gas Executive*. Other responsibilities included:

- Preparing briefing material for senior executive country visits.
- Analyzing power-generation industry developments as part of the Natuna LNG project.
- Researching, writing and delivering presentations to top management.
- Global macroeconomic forecasting (e.g., GDP, exchange rates, productivity, population).
- Analyzing government energy tax policies.

#### 1991–1994 Economic Analyst, U.S. Treasurers'

In his ten-year tenure with Exxon Mobil Corporation, Dr. York performed an extensive array of duties under many different titles. As an economic analyst, he conducted analysis of U.S. macroeconomic forecasting and fiscal policy. During this time, Exxon ranked among the top four economic forecasting groups in the U.S. private sector. Dr. York negotiated contract price clauses saving the company more than \$1 million. Also, he coordinated the estimation of the impact of the proposed 1993 BTU tax on Exxon Corporation's U.S. operations. Results were a key component of Exxon's successful opposition to the tax. He would also analyze government policies (e.g., NAFTA, the General Agreement on Tariffs and Trade, and health care reform). Dr. York was also given assignments in tax and antitrust court cases, contract negotiations, and productivity measurement studies.

#### **Publications**

"LNG Will Not Fill Natural Gas Demand." EnergyBiz, volume 1, number 1 (November/December 2004).

"LNG Hyped as Natural Gas Saviour." http://www.EnergyCast.com, October 2004.



"Limited Availability for Cheap LNG to the U.S." http://www.EnergyPulse.net, October 2004.

"The Role of LNG in East Coast Power Generation." http://www.EnergyPulse.net, June 2004.

"Regional Impact of Project Spending." Oil and Gas Executive, volume 1, number 1 (June 1, 1998). With Arbatov, Alexander A., Finken, Richard D., Moukhin, Andrei V., Suvorov, Anatoliy.

"Northern Gateway Terminal Project: Socioeconomic Study." With the Committee for Productive Forces and Natural Resources under the Russian Academy of Sciences, Moscow, Russia, September 1997.

"Russian Social and Economic Impact Evaluation for Large-Scale Oil and Gas Investments Under Six Production Sharing Agreements." With the Committee for Productive Forces and Natural Resources under the Russian Academy of Sciences, Petroleum Advisory Forum, Moscow, Russia, September 1996.

"An Applied General Equilibrium Model of International Tax Competition Among the Group of Seven Countries." Journal of Policy Modelling, spring 1993.

"A Numerical Example of a General Equilibrium Model with International Tax Competition." Atlantic Economic Journal Best Paper Proceedings, volume 1, number 1 (January 1991).

"Income Projections: Households and Families, Virginia Localities, 1990-1993." With John L. Knapp, Robert W. Cox, and Gerard E. Ward. Centre for Public Service, University of Virginia: Charlottesville, VA, August 1990.

"Should a Master's Degree be Required of All Teachers?" With John L. Knapp, Robert F. McNergney, and Joanne M. Herbert. Journal of Teacher Education, volume 41 number 2 (March-April 1990).

"Target Industry Study: Alleghany Highlands, Eastern Shore, Northern Neck, and Southside." With John L. Knapp, et al. Centre for Public Service, University of Virginia: Charlottesville, VA, September 1989.

#### **Speeches**

"Commercial Outlook for Storage Assets." Tank Storage Canada Conference, October 2009.

"Oil and Gas Market Outlook." FC Stone – Renewable Fuels Outlook Conference, September 2009.

"Energy and Feedstock Outlook." PCI 11th North American Polyester Conference, February 2009.

"Does \$100/bbl Oil Matter?: Implications of High Oil Prices." Gasification Technology Council, January 2008.

"Can SNG Keep Natural Gas Prices Down?" Designing & Operating Coal-Based Substitute Natural Gas Plants, April 2008.

"Impact of Structural Demand Forces on U.S. LNG Imports." LNG Summit, January 2007.

"Future of Natural Gas Demand For U.S. Industry." LNG Express, December 2006.

"LNG Hyped to U.S. Natural Gas Prices." Gasification Technology Council Annual Conference, October 2005.

"Availability of "Cheap" LNG to the US" Piper Rudnick Energy Marketplace, November 2004.



#### **Associations**

Council of Energy Advisors, Gerson Lehrman Group, 2004–2011 National Association of Business Economics, 1991–2011 International Association of Energy Economics, 1991–2011 **Honors** 

DuPont Fellow, University of Virginia, 1986–1989 Editor-In-Chief, Virginia Essays in Economics, 1987–1988 Phi Beta Kappa (Alpha Chapter), University of Wyoming, 1985 Richardson Fellow, University of Wyoming, 1981–1985

