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CATCHING THE BRASS RING: OIL MARKET DIVERSIFICATION POTENTIAL FOR CANADA

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SUMMARY

This paper examines the nature and structure of the Canadian oil export market in the context of world prices for heavy crude oil and the potential price differential available to Canadian producers gaining access to new overseas markets. Success in this arena will allow Canada to reap incredible economic benefits. For example, the near term benefits for increased access to Gulf Coast markets after mid-continent bottlenecks are removed, are significant, representing nearly 10$ US per barrel for Canadian producers. On the Pacific Coast, the world market is represented by growing capacity for heavy crude products in emerging Asian markets including Japan, Korea and China and existing heavy crude facilities in California and the west coast. Here, in the reference scenario for California and Asia the benefits are assumed to begin in 2020. The differential value range in California in 2020 is estimated at $7.20US per barrel and escalates to $8.77US by 2030. In Asia, the benefit range is estimated to grow from $11.15US per barrel in 2020 to $13.60US in 2030. Those higher prices for Canadian heavy oil would translate into significant increases in profits, jobs and government revenues. With better access and new pipeline capacity, oil producers will see more efficient access to international markets which can add up to $131 billion to Canada's GDP between 2016 and 2030 in the reference scenario. This amounts to over $27 billion in federal, provincial and municipal tax receipts, along with an estimated 649,000 person-years of employment. Alberta will be the principal but not sole beneficiary from increased access to world market pricing. Most provinces and territories will realize fiscal and economic gains from the distribution and sale of products reflecting reduced costs and increased access to refineries for heavy oil. The key to this change is the elimination of current bottlenecks in transport and the expansion of a network of pipelines that can move Canadian crude oil to locations reflecting minimal discounts from world market prices. As this paper demonstrates with hard facts and figures, the rewards are too great to ignore.

TABLE OF CONTENTS

I. Objectives and Scope ... 1
II. Introduction ... 2
III. Global Supply/Demand ... 5
- III.a Crude Flows & Infrastructure ... 8
- III.b Oil Characterization ... 8
- III.c Canadian Processing Capacity ... 9
- III.d US Processing Capacity ... 11

IV. US System Capacity and Constraints ... 16
- IV.a PAD Districts ... 16
- IV.b North American Future Infrastructure Investments ... 19

V. Crude Flows into the US: Constraints and Forecast ... 21
- V.a Historic Impact of Cushing Constraints on Crude Prices: WTI, LLS and Brent ... 24
- V.b Price Levels ... 28

VI. Canadian Export Opportunities ... 33
- VI.a Canadian Refining Capacity ... 34
- VI.b Canadian Export Potential: ... 36

VII. Pricing Benchmarks and Historical Trends ... 37
VIII. Future Price Differentials ... 41
IX. Impacts of Additional Revenue on the Canadian Economy ... 56
X. Conclusions ... 61
X. Bibliography ... 65

List of Tables

Table 1: Global Oil Demand and % increase by Region and by Country ... 7
Table 2: World Demand by Use ... 7
Table 3: Western Canadian Crude Supply CAPP June 2009 Growth Forecast ... 10
Table 4: Production vs. Imports in US ... 12
Table 5: Sources of US Supply ... 12
Table 6: PADD Capacity ... 13
Table 7: US Weight and Sulfur Characteristics on Average ... 14
Table 8: 2010 Heavy Crude Imports <25API Gravity ... 14
Table 9: 2010 Heavy Crude Imports Million Barrels Imported in 2010 ... 15
Table 10: US Refinery Upgrading Capacity (KBD) ... 15

Table 11: PADD 2 Flows (MBD) 18
Table 12: Summary of PADD District Flows 19
Table 13: Volumes In and Out of Cushing 22
Table 14: Relative Flows China vs. US and World Oil in MBD 30
Table 15: Dilbit Prices to Foreign Markets 32
Table 16: Mexican Crude Pricing Discounts for Quality 33
Table 17: Future Canadian Oil Market Potential 36
Table 18: Forecast Northeast Asian Demand 37
Table 19: Crude Oil Streams Evaluated for Computing Price Differentials 38
Table 20: Major Benchmarks used for Computing Price Differentials 44
Table 21: Crude Oil Prices Examined to Compute Total Price Differentials 46
Table 22: Illustrative Transit Costs Assumptions for WCS from Hardisty to USGC, BC, & Long Beach, $2010/bbl 48
Table 23: Heavy Crude Price Forecast 2011 to 2015 50
Table 24: Price and Differentials Forecast for Canadian Crude Exports 55
Table 25: Summary of Economic Impacts 57
Table 26: Midwest and Gulf Coast "Additional" Economic Impacts 2016-2030 58
Table 27: California "Additional" Economic Impacts 2016-2030 58
Table 28: Asia "Additional" Economic Impacts 2016-2030 58

Table of Figures

Figure 1: Oil Production 1980-2011 5
Figure 2: Total Price Differentials Average Heavy and Intermediate Benchmarks 6
Figure 3: Changes in World Oil Demand 6
Figure 4: Crude Flows by Region 8
Figure 5: US Imports from Canada of Crude Oil and Petroleum Products (Thousands of Barrels) 11
Figure 6: Petroleum Administration for Defense Districts 13
Figure 7: 2010 US Heavy Crude Imports API Gravity < 25 15
Figure 8: Location of US Refineries 2009 16
Figure 9: North Dakota Crude Oil Production 18
Figure 10: Existing and Proposed Canadian and US Pipeline Capacity 19
Figure 11: Pipeline Capacity Flows as of 1988 21
Figure 12: Pipeline Flows and Capacity at 2008 23
Figure 13: Cushing Inventory 24
Figure 14: Brent vs. LLS vs. WTI 2009 to 2011 25
Figure 15: Difference in Price Brent Minus WTI 26
Figure 16: WCS Pricing Relative to WTI and Brent 28
Figure 17: WCS Discount to WTI 29
Figure 18: Chinese Dependence on Imported Oil 30
Figure 19: Energy Consumption in the United States, China and India, 1990-2035 in Quadrillion BTU 31
Figure 20: China's Crude Oil Imports by Source 2009 31
Figure 21: Comparison of Refinery Yields by Crude Type 35
Figure 22: WTI, Brent Price Comparison 39
Figure 23: Monthly Average Price Diff with WCS to 2011 40
Figure 24: Quality Attributes Expressed as Price Differentials 45

I. OBJECTIVES AND SCOPE

This report examines the structure of the oil export market faced by Canadian producers. The current arrangement of Canadian export capacity is dependent on pipeline capacity that has evolved primarily to serve a single market, the United States, with limited tidewater capacity from Burnaby and Montreal. Proposed infrastructure expansion in key locations would alter this arrangement; new tidewater access will provide Canadian producers greater access to world markets, especially those with heavy crude oil processing capability.

Our objective is to define the range and magnitude of the price differential faced by Canadian heavy oil producers relative to world prices for similar crude blends. We examine the history of oil price differentials over the past decade using various benchmark indicators for a range of heavy oil products available from Canadian sources, primarily those heavy oils developed from the oil sands region in the great sedimentary basin in Alberta. Our primary goal is to isolate the core price fundamentals for this product, including transportation and limited upgrading necessary for shipment and to compare the value of the residual product for existing and emerging markets. We then establish a residual discount that reflects the Canadian exports to a single primary market, namely the US.

We critically review pricing differentials for various heavy crude products and examine the strength of markets both in the US and Asia to absorb the product relative to their ability to process and distribute the distillate elements. The capacity constraints in the US pipeline and processing system dominate price characteristics, especially in terms of producer preferences, geographic and processing constraints and competition from lighter and sweeter alternative products.

We conclude with an estimate of the long-term price differential facing Canadian producers over the next decade, growth in foreign markets and expected capacity changes in the US that will alter the current price differentials with and without proposed pipeline additions and estimate the economic impact throughout Canada if this differential were captured by Canadian producers.

II. INTRODUCTION

This report addresses the issue of competitive pricing and differentials for Canadian heavy oil destined for refining in the US or other world markets. We have examined the pricing relationships for heavy oil products with a range of API and sulfur characteristics and determined the likely differential for Canadian products that trade in or are based in the same markets. In the report we calculate a likely differential that describes available pricing headroom, that is, the additional value that is available for a variety of reasons today to Canadian producers.

The current pricing of Canadian heavy oil products, which originate primarily in Alberta, reflects a quality discount applied to Western Canadian Select (WCS), a blend selected as representative of heavy oils from this region in general, plus a transportation cost that corresponds to delivery charges for the end refineries in the US.

Heavy oil commodities are dependent on processing from specialized refineries, which are predominantly found in the Gulf Coast and Midwest. Gaining access to these refineries is made more difficult at the present time due to physical constraints in the centre of the US (at Cushing, OK), where supplies are transferred to appropriate facilities. This constraint results in an additional price discount for Canadian heavy oil, in addition to the quality discounts already imposed.

Lifting this constraint will result in lower transportation costs and more efficient delivery to heavy oil-capable refineries in the Gulf Coast. The added benefit will allow a new pricing paradigm, namely using benchmarks other than West Texas Intermediate (WTI) and Brent Crude in order to establish price equivalency for WCS. This change, reflecting the change in availability of both WCS and Bakken from the upper Midwest, offers the opportunity to use a more appropriate benchmark for pricing of Light Louisiana Sweet (LLS) as the world price benchmark, and to use a representative proxy already traded on the Gulf Coast, Maya, for WCS. Maya is similar in gravity and sulfur and is currently imported for processing in Gulf Coast refineries. Although supplies of this benchmark crude are in decline, its characteristics serve as an effective proxy for WCS. For all intents and purposes, marginal barrels of WCS reaching Gulf Coast refineries are likely to displace current imports of Maya, but more importantly, will be priced at the equivalent discount of Maya to LLS during the period 2016-2030.

The magnitude of the differential is impressive, and is derived principally from a new pricing for WCS relative to LLS, effectively compressing and reducing the overall discount for quality, and from the reduction of a substantial fraction of the overall cost of transporting Canadian heavy crude to appropriate refineries. Increased access to the Gulf Coast, and in the case of the Pacific Coast, to appropriate new markets, results in the creation of a similar differential fraction, at a slightly later date.

The differential value range (headroom) represented for crude priced at the new Gulf Coast is approximately $9.50US (international oil values in this report are expressed in US$) in 2016, rising to $12.50US in 2030, a reflection of increased demand matched to available processing capacity. On the Pacific Coast, the market is represented by growing excess capacity for heavy crude in California, and in emerging refining capacity in Asian markets including Japan, Korea and China. The differential value range in California in 2020 is estimated at $7.20US per barrel and escalates to $8.77US by 2030. In Asia, the benefit range is estimated to grow from $11.15US per barrel in 2020 to $13.60US in 2030. It is important to note that these are based on a scenario rather than a forecast, and represent maximum expected additional value available to Canadian producers during this period. These figures do not estimate the likely returns, only the maximum potential.

When viewed in terms of economic activity, the opportunity to achieve these new price and processing levels produces substantial returns for Canadian resources. In the model, runs for likely investment, reinvestment, employment and spending over the study period amount to an additional $132 billion Cdn in increased GDP between 2016 and 2030, of which $36 billion Cdn in employee compensation (27%), and additional employment of 649,000 person years. The public purse benefits as well, with $27 billion Cdn in increased federal, provincial and municipal government revenues, largely concentrated in Alberta. The outcome in terms of GDP throughout the Canadian economy of exploiting the full range of this differential is not trivial, approaching one percent annually in an economy currently estimated at $1.57 trillion.

The Current Market Conditions

Canadian heavy oil has been trading at a discount to other crude products as a reflection of geography, economic markets and product characteristics. Given Canada's proximity and long history of supplying the US with crude oil products, natural gas and electricity, the design and demand characteristics of US energy markets largely dictate price levels.

The path to this economic and trading relationship has historical roots not unlike employment tradeoffs between security and risk as a proxy for pay levels. Over time, the capital available for upgrading high volumes of crude oil was more accessible in the US, which also had large reserve stores within economic transportation distance from refineries. Compounding this relationship has been a lack of tidewater export access within Canada. Ultimately, commitments for pipeline construction have further solidified this relationship with the result that the primary client for Canadian energy supplies is the US. Canada effectively becomes a price-taker in return for stable and predictable markets. Recent events have changed this relationship. US demand has flattened, supplies of more traditional as well as US domestic crude resources have increased, all while the world price for heavy oils have become more competitive. Overcoming price discounts and diminishing transportation costs have become an imperative for expansion of Canadian oil resources and the maintenance of competitive markets.

The current oil market for Canadian crude is dominated by pipeline constraints in the American Midwest, further complicated by the fact that the price benchmarks for WCS of West Texas Intermediate (WTI) and Brent world prices have been so far apart. Much of the constraint reflects the fact that in the short term, the Midwest is oversupplied in part due to Canadian imports plus Bakken domestic crude, and that the crude oil cannot get down as far as the Gulf Coast and appropriate refining capability. There are two pipelines that currently bring oil north from the Gulf Coast to the Midwest, which increases the impact of excess crude oil supply for Midwest refineries and results in lower price levels for WTI crude as a benchmark at Cushing. Perversely, demand for refinery products remains high even when prices for crude oil are low, providing a profit incentive for refiners.

Some fixes for this issue are available and will potentially appear in the market by the transition date of 2016 cited in this report. One of these, reversing the Seaway pipeline, has been announced by Conoco Phillips and Enbridge, which when combined with other proposed pipeline expansion projects, will substantially reduce the congestion effect.

Limits to the Report

This report identifies the potential price differential available for Canadian heavy oil products that can reach and be priced based on world oil price levels with limited discounts for quality and transportation costs. It is specifically not a price forecast, and in fact relies on price forecasts for heavy oil products recently filed with the National Energy Board on the Gateway project. It is limited as well, by confining the analysis to a single representative blend of Canadian heavy oil products, WCS, and does not seek to model or estimate the behaviour of a range of lighter, sweeter products available elsewhere in Canada.

Notwithstanding these caveats, the report identifies the nature and magnitude of the gap in current pricing levels vs. the potential available on world markets. Over the last decade, refining capacity built to process heavy crude products has expanded significantly worldwide, a reflection of the type of resource available in the market. In the case of the principal market, the US, this refining capacity reflects capital investment decisions made by the US and by Canada that literally lock in trading relationships in the absence of new pipe capacity or tidewater access. The appetite for heavy oils reflects not only the decline in lighter, sweeter blends, but also the ready access and large reserves characteristic of Canadian resources.

However, shipping and processing these products reflects day-to-day trading choices and market-based decisions largely independent of geopolitical interests, such as security or policy directives. Acquisition of supplies from a refiner's perspective is purely economic, reflecting variables such as market price, quality discounts and adjustments, contract terms, distance and overall derived product demand.

No producer is likely to capture the full range of this differential; rather the numbers represent a capacity growth target. In the near term to 2030, the available processing capacity in the US will absorb up to an additional 1.5 MBD, much of which will be supplied from domestic sources. We believe the proposed increment of 0.7 MBD of capacity represented by the Keystone XL pipeline or substitutes will be accommodated within existing refining capacity and will command a premium over current price levels.

This same phenomenon is expected to prevail on the West Coast as well, once new pipeline capacity is available, which we estimate will occur in some form by 2020. The result will be expanded capacity beyond the Trans Mountain pipeline to Burnaby, currently providing approximately 0.3 MBD. We believe this additional capacity will accommodate 0.5 MBD of heavy crude to these markets. Since prices reflect overall supply/demand dynamics, the world price can be expected to adjust accordingly. This effect is not modeled in this report although in the short term, benchmark prices for LLS and Brent are likely to fall with rising prices for substitute crudes such as Maya, SJV heavy and Arab Medium. The result will narrow the spread or discount faced by Canadian crude producers. For this report, we expect Canadian production to increase to match new transfer capacity in the report period. Beyond this period, without additional capacity, oil sands expansion will be necessarily curtailed.

We have relied on the Alberta Energy Resources Conservation Board (ERCB[1]) estimates of supply and demand and recent filings at the National Energy Board to establish a base case for Canadian discoverable and recoverable resources plus EIA and IEA estimates of future demand, supply and pricing in their annual energy outlooks.[2] This includes estimates of overall energy production, including crude bitumen, crude and synthetic crude prices,[3] demand and costs.

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[1] ERCB 2009, *Supply and Demand Outlook*.

[2] IEA 2010, EIA 2011

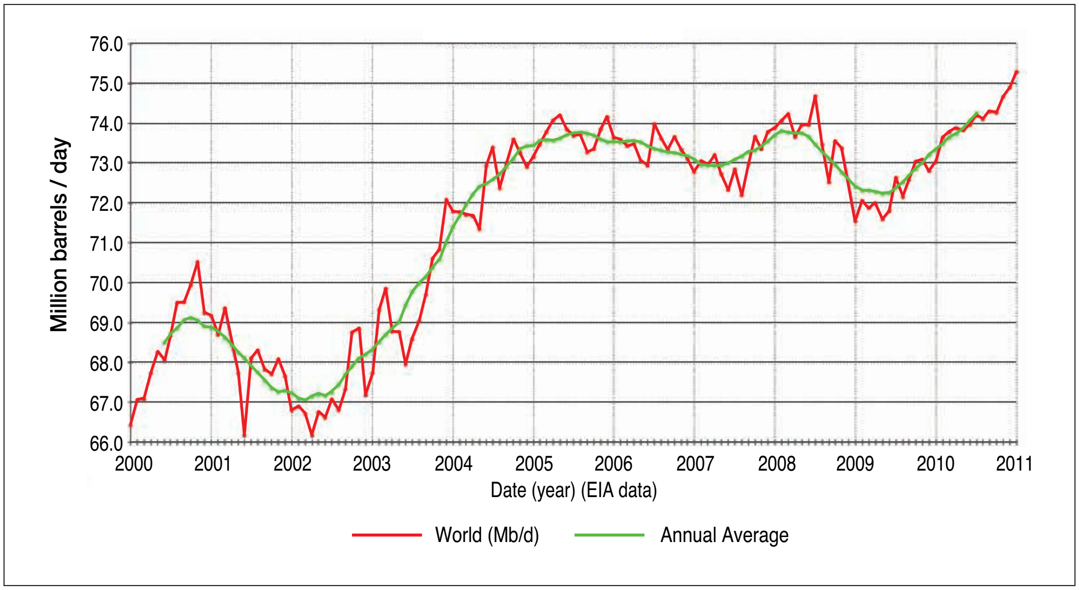
[3] The ERCB uses West Texas Intermediate (WTI) price forecast which in 2009 forecast $55/ bb1 rising to $120/bbl in 2018.

III. GLOBAL SUPPLY/DEMAND

Oil, ranging from partially upgraded crude to derivative products, is an essential commodity worldwide. Oil prices are broadly adjusted for discovery, quality and transportation based on the processing capability of the receiving entity; once adjusted, oil said to be fungible, albeit not perfectly,[4] on a worldwide basis in markets capable of handling various ranges of quality.

While not as volatile as natural gas, for example, world prices of oil have had several price excursion periods, typically linked to broader economic trends.[5] Generally, oil prices saw a relative price decline from the early 1980s, followed by a stable period until roughly 2000, at which point prices begin to increase again with indications of increasing demand and local scarcity in capacity or declining reserves.

FIGURE 1: OIL PRODUCTION 1980-2011



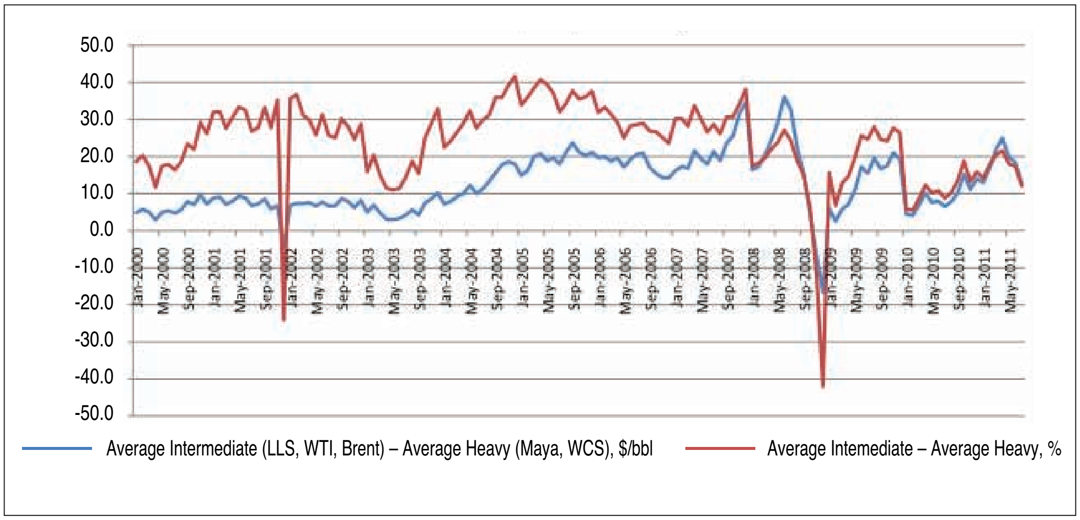
Source: EIA, SEO 2011

When heavier grades of crude are segregated, we can see the relative stability of prices in Figure 2, influenced by existing and limited capacity of processing facilities capable of handling these blends, with declines coinciding directly with strong recessionary periods.

4 Variables such as political sanctions or preferences may significantly alter this base characteristic, but are by themselves not forecastable, nor are they included in this analysis.

5 For more on the prediction of oil prices, see J. Smith, World Oil: Market or Mayhem?, Journal of Economic Perspectives, Vol 23:3,2009 , pp. 145-164

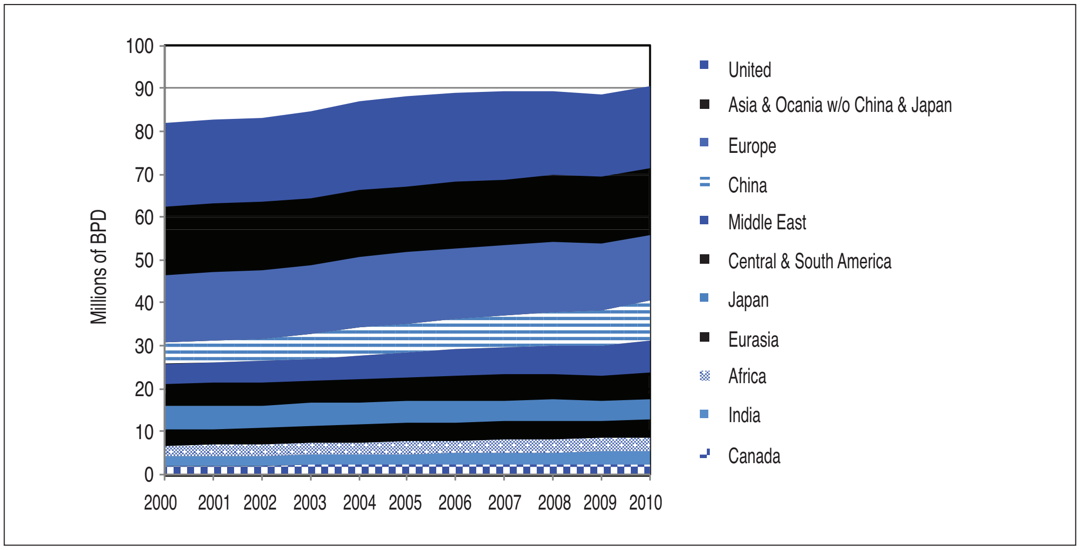
FIGURE 2: TOTAL PRICE DIFFERENTIALS AVERAGE HEAVY AND INTERMEDIATE BENCHMARKS



Source: US Energy Information Administration

While petroleum product demand in the US has been fairly static for much of the last decade, hovering around 20 MBD, global demand has been increasing pushed higher mainly by expanding economies in Asia and Africa. Demand has almost doubled in China (+91.6 percent) and has grown by 50 percent in India, by 33 percent in Africa and by 23 percent in Brazil as well as in aggregate for Central and South America. Overall demand in Europe has fallen (-3.8 percent) due to significant declines in demand in the United Kingdom, France, Germany, Spain and Italy, although demand in Eastern Europe is on the rise, albeit from a very low base.[6]

FIGURE 3: CHANGES IN WORLD OIL DEMAND



Source: US Energy Information Administration

When broken down by region and country, the net growth rates illustrate clearly where demand was concentrated over the past decade as shown in Table 1, below.

[6] US Energy Information Administration, *Total Petroleum Consumption*, http://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm?tid=5&pid=5&aid=2

TABLE 1: GLOBAL OIL DEMAND AND % INCREASE BY REGION AND BY COUNTRY

Region	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	% Inc 00-10
United States	19.7	19.65	19.76	20.03	20.73	20.8	20.69	20.68	19.5	18.77	19.18	-3%
Other Asia	15.72	15.77	15.78	15.59	15.61	15.52	15.47	15.52	15.62	15.86	15.73	0%
Europe	15.91	16.09	16.05	16.16	16.29	16.42	16.43	16.25	16.16	15.42	15.31	-4%
China	4.8	4.92	5.16	5.58	6.44	6.7	7.26	7.53	7.82	8.32	9.19	91%
Middle East	4.79	4.95	5.12	5.3	5.56	5.83	6.04	6.26	6.62	6.83	7.35	53%
Latin America	5.21	5.33	5.24	5.2	5.35	5.48	5.73	5.92	6.09	6.13	6.36	22%
Japan	5.52	5.41	5.32	5.43	5.32	5.33	5.2	5.04	4.79	4.39	4.45	-19%
Eurasia	3.72	3.78	3.83	3.91	4.04	4.15	4.19	4.09	4.2	4.14	4.29	15%
Africa	2.5	2.6	2.67	2.72	2.82	2.97	3.04	3.12	3.19	3.23	3.35	34%
India	2.13	2.18	2.26	2.35	2.43	2.51	2.69	2.8	2.95	3.11	3.18	49%
Canada	2.01	2.04	2.07	2.19	2.28	2.31	2.23	2.28	2.23	2.16	2.21	10%
World	76.78	77.51	78.16	79.71	82.53	84.06	85.13	85.81	85.30	84.33	87.08	13%

Source: US Energy Information Administration

While greater than 70 percent of petroleum product demand in the US is for transportation fuels, primarily gasoline, the same is not necessarily true around the world. Table 2 illustrates the regional differences in demand.

TABLE 2: WORLD DEMAND BY USE

2010	Motor & Aviation Gasolines	Jet Fuel, Heating Oil & Kerosene, Diesel Fuels	Marine Bunker Fuel & Crude Oil Used as Fuel	Total Transportation Fuels
US	48.6%	28.5%	2.9%	80.00%
Europe	22.4%	50.5%	8.1%	81.00%
Latin America	30.1%	36.1%	12.4%	78.60%
Africa	24.4%	45.2%	13.6%	83.20%
Asia/Oceania	30.6%	36.1%	11.6%	78.30%
China	27.1%	39.5%	7.4%	74.00%
Japan	39.1%	31.1%	10.0%	80.20%

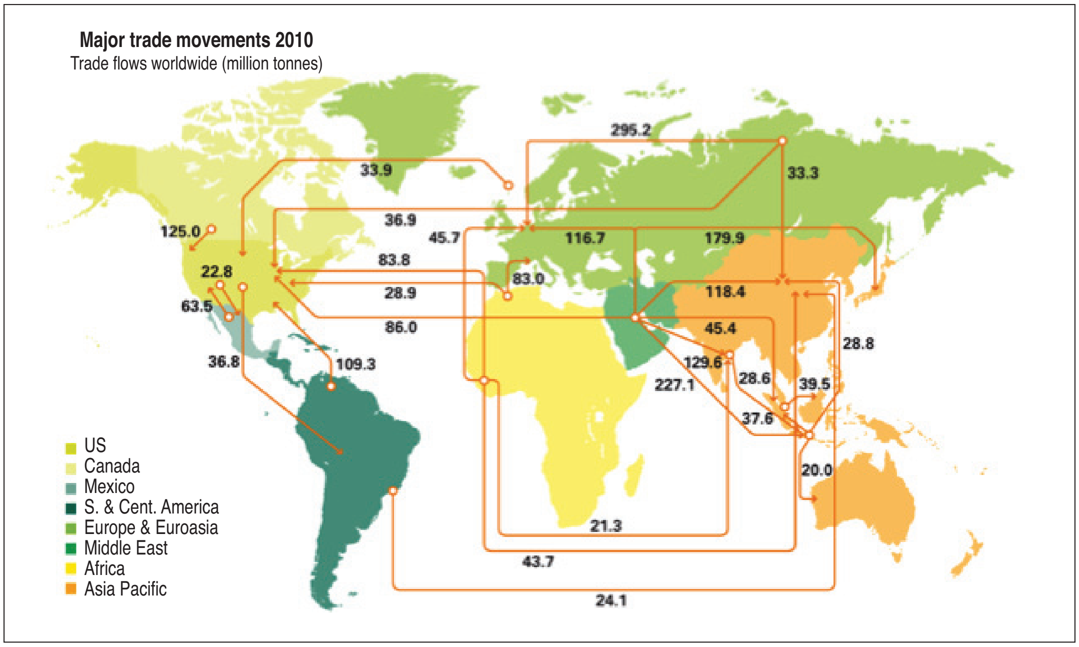
Source: BP Statistical Review of World Energy 2011

These demand profiles, along with refining infrastructure, determine the qualities of crude processed around the world. While US refineries have made significant investments in complex refining hardware, which supports processing heavier, sourer crude into gasoline and distillates, similar investment outside the US has been pursued less aggressively. As a result, in 2010 about 75 percent of crude inputs in Europe were light sweet and light sour grades, and in the Asia Pacific region light sweet and sour crudes accounted for about two-thirds of total crude inputs. More recently, there has been considerable interest and investment in expanding heavy crude processing capacity outside the US, primarily in China, including coking, fluid catalytic cracking and hydrocracking capability. In Asia, generally, heavy crude processing capacity is expected to increase, although the time periods are uncertain and ultimately will reflect the volumes of lighter, sweeter crudes available from more conventional sources replaced by heavier crude supplies. As these upgrading and new refinery projects are completed, crude slates worldwide are expected to shift dramatically toward heavy sour crude.

III.a Crude Flows & Infrastructure

Crude oil is a global commodity and as a result, crude flows around the world from producing centres to refining centres, which historically have been the centres of demands as well. The following map highlights crude flows from producing areas to refining areas showing the dominance of seaborne transport from producing to receiving regions. The limited exports from Western Canada reflect the constraints from a system primarily servicing US-based refineries.

FIGURE 4: CRUDE FLOWS BY REGION



III.b Oil Characterization

Crude oil varies widely in quality. Crude oil is typically and most simply classified based on API gravity[7] and sulfur content, both of which affect refining costs and the products into which crude oil can be refined. A crude oil with a high API gravity is relatively less dense and is considered a light crude. A crude with a low API gravity is more viscous and is considered a heavy crude.

The US EIA defines light crudes as those with API gravity of greater than 38 degrees and heavy crudes as having API gravity of 22 or less. Intermediate crude oils have API gravities between 22 and 38 degrees. Lighter crudes produce a higher percentage of higher-valued gasoline and distillates (heating oil, diesel and jet fuel) with simple refining (distillation), while heavier crudes produce more lower-valued residual fuel oil and less gasoline and distillate.

[7] API gravity is a scale expressing the gravity or density of liquid petroleum products. It is calibrated in degrees API and is calculated as follows: Degrees API = (141.5 / (sp. gr. 60ºF / 60ºF)) - 131.5. The higher the API gravity, the lighter the product.

Crude oil is also classified based on sulfur content. Sweet crude is low in sulfur, commonly less than 0.5 Wt. percent sulfur while sour crude is high in sulfur, typically 1.0 Wt. percent or higher. Crude oils with sulfur content between 0.5 percent and 1.0 percent are often labeled medium sour crudes. Sour crudes require more sophisticated refining to reduce sulfur levels of refined products and as a result are more costly to process. Definitions of sweet and sour and heavy and light do vary. For example, per the National Energy Board of Canada, a heavy crude has an API gravity less than ~30 degrees API and a light crude has an API gravity greater than 30 degrees API. [NTD: A medium sour crude is more commonly thought of as a medium heavy crude (~30 degrees API) that is sour (~>1.0 wt.S)]. In some reservoirs, crude products with gravity as low as 7 or 8 degrees can range from "heavy to ultraheavy," a measure of API, because they are typically extracted using heavy oil production and processing methods.[8] Heavy oils' dominant characteristic is a high fraction of asphaltenes in the crude oil sample. Most of the Western Sedimentary Basin products fall in the heavy oil category whether they are extracted using surface mining or in-situ processing techniques. The products are typically mixed with diluent in order to facilitate transportation to out-of-country upgrading facilities.

III.c Canadian Processing Capacity

Canada has limited processing capacity, especially that needed to deal with heavy oil products. According to NRCan,[9]

"The transportation costs associated with moving crude oil from the oil fields in Western Canada to the consuming regions in the east and the greater choice of crude qualities make it more economic for some refineries to use imported crude oil. Therefore, Canada's oil economy is now a dual market. Refineries in Western Canada run domestically produced crude oil, refineries in Quebec and the eastern provinces run primarily imported crude oil, while refineries in Ontario run a mix of both imported and domestically produced crude oil. In more recent years, eastern refineries have begun running Canadian crude from east coast offshore production."

According to NRCan, Canadian processing includes primarily cracking refineries. These refineries run a mix of light and heavy crude oils to meet the product slate required by Canadian consumers. Historically, the abundance of domestically produced light sweet crude oils and a higher demand for distillate products, such as heating oil, than in some jurisdictions reduced the need for upgrading capacity in Canada. However, in more recent years, the supply of domestic light sweet crude has declined and newer sources of crude oil tend to be heavier. Many of the Canadian refineries are now being equipped with some upgrading capability to handle the heavier grades of crude oil currently being produced.

Refinery configuration is also influenced by the product demand in each region. Nationally, gasoline accounts for about 40 percent of demand with distillate fuels representing about one-third of product sales and heavy fuel oil accounting for only eight percent of sales. Total petroleum product demand is distributed almost equally across three regions, with Atlantic/Quebec, Ontario and the West each accounting for about one-third of total sales. However, the mix of products varies significantly among the regions.

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[8] The precise definitions vary, and since data has been taken from a variety of sources, there will be some inconsistency, but that inconsistency does not affect the results.

[9] NRCan, 2011, Fuel Focus, http://www.nrcan.gc.ca/energy/sources/petroleum-crude-prices/gazoline-reports/2011-10-21/1874, and www.nrcan.gc.ca/sites/www.nrcan.gc.ca.energy/.../pcopdp-eng.pdf

Many US refineries, especially in the Midwest and on the Gulf Coast, are configured to process a large percentage of heavy, high-sulfur crude and to produce large quantities of transportation fuels, and low amounts of heavy fuel oil. US refiners have generally invested in more complex refinery configurations with higher processing capability, allowing them to use cheaper feedstocks. Canadian refineries do not have the high conversion capability of the US refineries, because, *on average*, they process a lighter, sweeter crude slate. Canadian refineries also face a higher distillate demand, as a percent of crude, than those found in the US so gasoline yields are not as high as those in the US, although they are still significantly higher than European yields.

The relationship between gasoline and distillate sales creates challenges for refiners. Any refinery has a limited range of flexibility in setting the gasoline-to-distillate or other products production ratio based on changes in demand, as well as their own capacity.

A critical measure in refining economics is the utilization rate and the resultant efficiency ratio of operations. Currently there are only 19 refineries producing petroleum products in Canada, versus 148 in the US, although Canadian refining capacity has increased overall. There has been a corresponding increase in capacity utilization, increased operating efficiency and lower costs per unit of output. Consequently, refinery utilization rates have been above 90 percent nationally for six of the last 10 years. A utilization rate of about 95 percent is considered optimal as it allows for normal shutdowns required for maintenance and seasonal adjustments.

The summary of Canadian crude flows is available from the Canadian Association of Petroleum Producers (CAPP) and is shown below in Table 3.

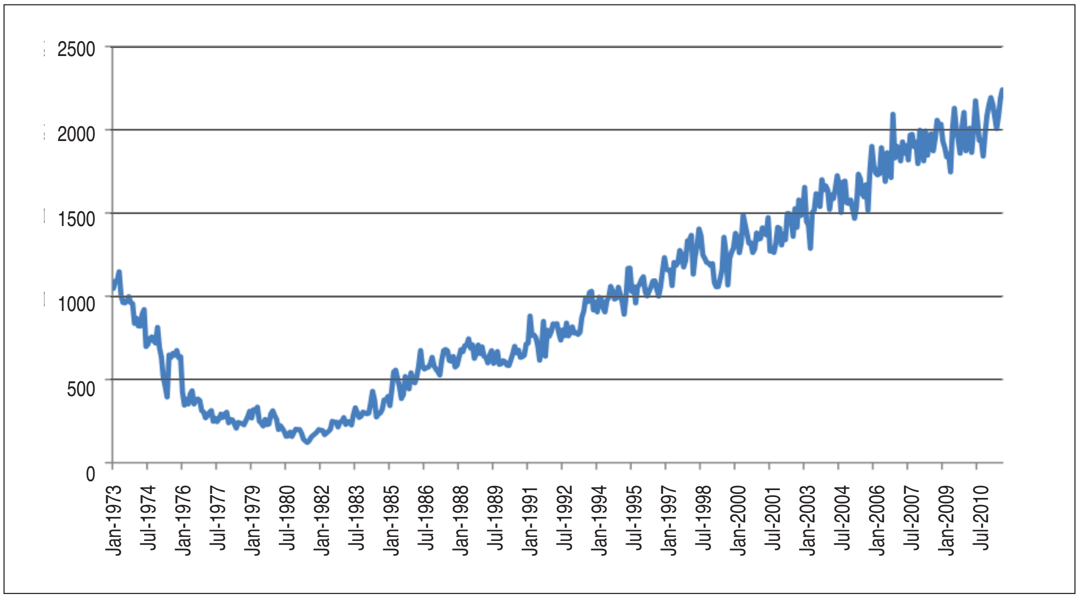
TABLE 3: WESTERN CANADIAN CRUDE SUPPLY

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Canadian Mixed Sweet	431	425	415	406	393	381	369	357	345	333	322	311	300	289	278	267	258
Canadian Mixed Sour	151	150	146	142	138	134	130	125	121	117	113	109	105	101	98	94	90
Sweet Synthetic	446	614	677	703	722	757	801	845	872	929	986	1042	1074	1128	1133	1135	1134
Sour Synthetic	169	174	177	186	192	198	201	203	204	205	205	205	205	205	205	205	205
Conventional Heavy	323	303	286	274	262	251	240	229	219	209	200	191	182	173	165	157	150
Western Canadian Select	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Cold Lake Blend	482	521	573	579	658	732	725	720	702	663	647	639	639	639	639	639	639
Athabasca DilBit	240	280	283	330	386	489	593	763	887	973	1097	1192	1220	1237	1371	1465	1514
Total Conventional Light/Medium	582	575	561	548	531	515	499	482	466	450	435	421	405	390	375	361	348
Total Synthetic	615	788	854	889	914	955	1002	1048	1076	1134	1191	1247	1279	1332	1338	1340	1339
Total Heavy	1295	1354	1392	1434	1556	1722	1807	1962	2058	2095	2194	2271	2291	2299	2425	2512	2553
Grand Total	**2492**	**2717**	**2808**	**2870**	**3001**	**3192**	**3308**	**3492**	**3600**	**3680**	**3820**	**3939**	**3975**	**4021**	**4138**	**4213**	**4240**
Year-on-Year Increase		225	91	62	131	191	116	184	108	79	140	119	36	46	117	75	27
Cumulative Increase		225	316	378	509	700	816	1000	1108	1188	1328	1447	1483	1529	1646	1721	1748
Percent of Total																	
Total Conventional Light/Medium	23%	21%	20%	19%	18%	16%	15%	14%	13%	12%	11%	11%	10%	10%	9%	9%	8%
Total Synthetic	25%	29%	30%	31%	30%	30%	30%	30%	30%	31%	31%	32%	32%	33%	32%	32%	32%
Total Heavy	52%	50%	50%	50%	52%	54%	55%	56%	57%	57%	57%	58%	58%	57%	59%	60%	60%

Source: Muse-Stancil, 2010 adapted from CAPP June 2009 Growth Forecast

The majority of Canadian crude exports transfer to US refineries. This volume has been increasing over time as depicted in Figure 5 below.

FIGURE 5: U.S. IMPORTS FROM CANADA OF CRUDE OIL AND PETROLEUM PRODUCTS (Thousands of Barrels per Day)



Canada has some limited export capacity, as well as exchange capacity in the east. Most of this capacity is represented by two lines: Line 9 extending from Sarnia, Ontario to Montreal, Quebec with exchange capacity to and from the US, and the PMPL or Portland-Montreal pipeline that has the capability to reverse flows in one of two 236-mile-long pipelines that travel underground between South Portland and Montreal.

Line 9 currently has a capacity of 240,000 bbl/day and is currently accommodating imports of oil to Canada, although it has experienced flow reversal in the past. Pipeline reversal in the PMPL line is now planned to continue beyond Montreal, to include reversing the flow of a supply pipeline from Portland, ME so that the oil from Alberta might also supply northern New England. Oil exported past Portland is moved via tanker to processing facilities in the East Coast and to Gulf Coast refineries. The prices for these crude products are based on a similar formula of discounts of WTI to Brent. We expect the differential to be based on the proposed LLS to Maya discount in the future and expect no significant volume increase in the study period.

III.d US Processing Capacity

About 86 percent of the petroleum products consumed in the US in the last decade were refined in the US. As of year-end 2010, the US had 17.5 MBD of operating refining capacity. However, most of the crude oil input to US refineries was imported in 2010, which has been the case historically and which continues to be true.

TABLE 4: PRODUCTION VS. IMPORTS IN US

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Production	5.8	5.8	5.7	5.7	5.4	5.2	5.1	5.1	5.0	5.4	5.5
Imports	9.1	9.3	9.1	9.7	10.1	10.1	10.1	10.0	9.8	9.0	9.2

Source: US Energy Information Administration

In 2010 the US produced 5.5 MBD of crude oil and imported 9.2 MBD. Crude imports were split almost 50/50 between OPEC and non-OPEC producers, with imports from non-OPEC countries making up a slightly higher percentage of the total. Canada's share of US imports has increased steadily over the past decade, and since 2004 Canada has been the largest supplier of imported crude oil to the US. Historically, the US has been the primary market for Canadian crude oil.

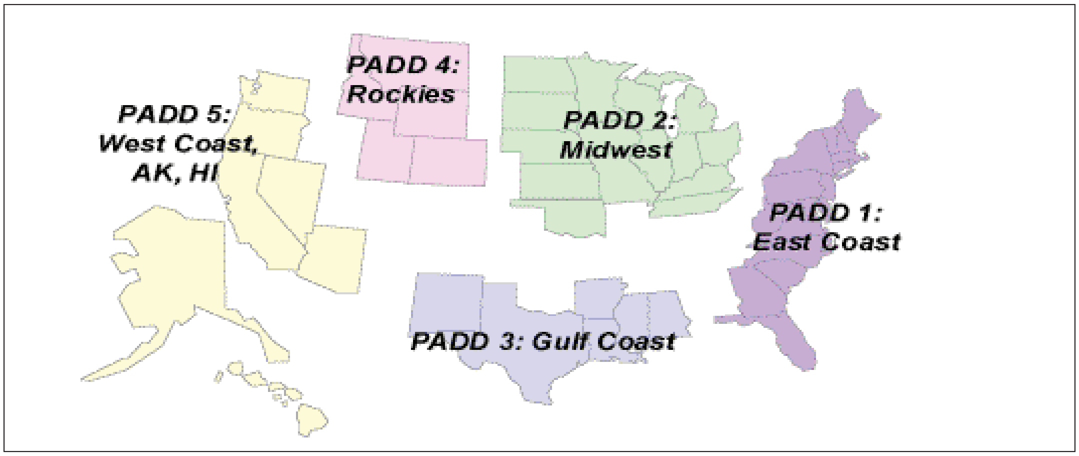
TABLE 5: SOURCES OF US SUPPLY

Country of Origin	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Canada	1.348	1.356	1.445	1.549	1.616	1.633	1.802	1.888	1.956	1.943	1.970
Mexico	1.313	1.394	1.500	1.569	1.598	1.556	1.577	1.409	1.187	1.092	1.152
Saudi Arabia	1.523	1.611	1.519	1.726	1.495	1.445	1.423	1.447	1.503	0.980	1.082
Nigeria	0.875	0.842	0.589	0.832	1.078	1.077	1.037	1.084	0.922	0.776	0.983
Venezuela	1.223	1.291	1.201	1.183	1.297	1.241	1.142	1.148	1.039	0.951	0.912
Total Imports	**9.071**	**9.328**	**9.14**	**9.665**	**10.088**	**10.126**	**10.118**	**10.031**	**9.783**	**9.013**	**9.213**

Source: US Energy Information Administration

In the US, there are a number of major refining centres. To understand how crude oil, both domestically produced and imported, is delivered to and moves between refining centres, it is necessary to understand US crude oil and petroleum product infrastructure. To do that it is helpful to understand the Petroleum Administration for Defense Districts or PADDs that define geographies and are used for aggregating and organizing statistics and information. PADDs were established during the Second World War to facilitate the allocation of petroleum-derived fuels, mainly gasoline and diesel fuel. There are five districts or PADDs, as follows. PADD I has been subdivided into smaller geographies to accommodate differences in crude and product flows between the subdivisions.

FIGURE 6: PETROLEUM ADMINISTRATION FOR DEFENSE DISTRICTS



Source: US Energy Information Administration

- PADD 1(East Coast) is composed of the following three sub-districts:
  - Sub-district A (New England): Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
  - Sub-district B (Central Atlantic): Delaware, District of Columbia, Maryland, New Jersey, New York and Pennsylvania.
  - Sub-district C (Lower Atlantic): Florida, Georgia, North Carolina, South Carolina, Virginia and West Virginia.
- PADD 2 (Midwest): Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, South Dakota, Ohio, Oklahoma, Tennessee and Wisconsin.
- PADD 3 (Gulf Coast): Alabama, Arkansas, Louisiana, Mississippi, New Mexico and Texas.
- PADD 4 (Rocky Mountain): Colorado, Idaho, Montana, Utah and Wyoming.
- PADD 5 (West Coast): Alaska, Arizona, California, Hawaii, Nevada, Oregon and Washington.

TABLE 6: PADD CAPACITY

PADD	Location/ Geography	Total Number of Refineries	Number of Operating Refineries	Operable Capacity MBD	Current Coking Capacity KBD	Planned Additional Coking+ Capacity KBD*
1	East Coast	13	10	1.4	93.7	–
2	Midwest	27	26	3.7	373.9	147
3	Gulf Coast	57	54	8.6	1,318.4	225
4	Rocky Mountains	17	15	0.6	80.4	–
5	West Coast, AK, HI	34	32	3.2	530.4	–
Total		**148**	**137**	**17.5**	**2,396.8**	**372**

Source: US Energy Information Administration

** Anticipated by year-end 2012 + coking capacity is a convenient proxy for a refinery's ability to process heavy crude*

During 2010, US crude imports ranged from very light sweet crude from Nigeria, with sulfur of 0.01 percent and API gravity of 68 degrees, to very heavy sour crude from Venezuela with 5.5 percent sulfur and 10.5 degrees API gravity.

The weighted average crude oil sulfur and API gravity specifications for total crude processed by US refineries has remained fairly consistent over the past decade.

TABLE 7: US WEIGHT AND SULFUR CHARACTERISTICS ON AVERAGE

Specification	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
WT% Sulfur	1.34	1.42	1.41	1.43	1.43	1.42	1.41	1.43	1.47	1.4	1.39
API Gravity	30.99	30.49	30.42	30.61	30.18	30.2	30.44	30.42	30.21	30.37	30.71

Source: US Energy Information Administration

The US refining sector is characterized by substantial complex refining capacity that can process heavy sour crudes into the transportation fuels that characterize US petroleum product demand. As a result, about half of crude inputs in the US are medium and heavy sour crudes and the US is continuing to expand heavy crude processing capacity.

In 2010, the weighted average sulfur and API gravity specifications of crude imported into the US were comparable to the weighted average specifications for all crude processed by US refineries. Imports were slightly sourer, with average sulfur of 1.64 and slightly heavier, with API gravity of 28.8.

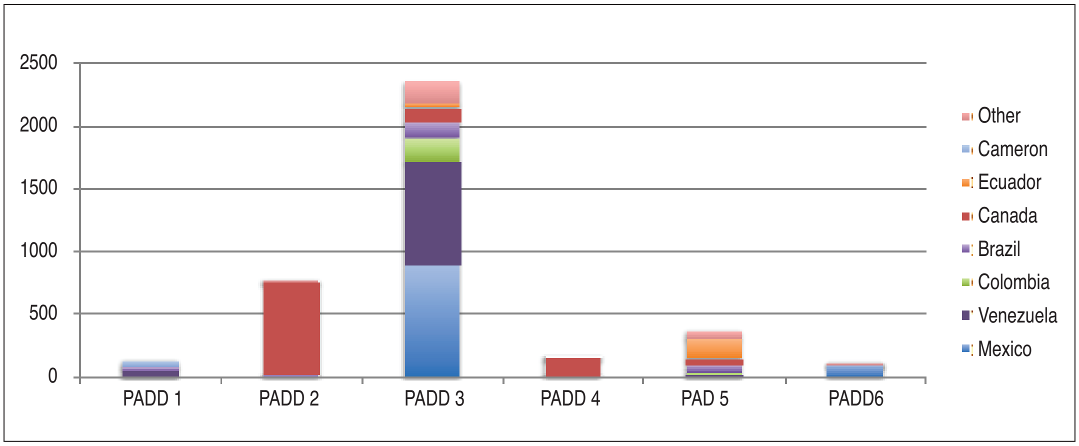
TABLE 8: 2010 HEAVY CRUDE IMPORTS <25API GRAVITY

KBD	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	PADD 6*	TOTAL
Mexico	2	–	897	–	–	96	995
Venezuela	40	–	819	–	8	–	867
Colombia	–	–	182	–	24	–	206
Brazil	31	12	134	–	61	–	239
Canada	8	743	117	156	52	–	1,076
Ecuador	–	–	29	–	153	–	182
Cameroon	46	–	2	–	–	–	48
Other	0	0.34	177	–	73	3	254
TOTAL	128	755	2,356	156	373	99	3,867
Canada as a % of Total	6%	98%	5%	100%	14%	0%	28%

**PADD 6 has been more recently designated for the Virgin Islands*

PADD 3 refiners processed 2,356 KBD of crude oil similar to WCS in 2010, but only 117 KBD was Canadian. PADD 5 refiners processed 373 KBD of crude oil similar to WCS, but only 52 KBD was Canadian. All else being equal, these refineries could process an additional 2,560 KBD of WCS if the distribution system was capable of delivering the volume.

FIGURE 7: 2010 US HEAVY CRUDE IMPORTS API GRAVITY < 25



Crude imported from Canada was generally heavier and sourer than other US imports, at an average 2.2 Wt. percent sulfur and 26.7 degrees API gravity, but quality ranged from a heavy sour with 4.1 percent sulfur and 14.1 API gravity (from Western Canada) to very light sweet with 0.5 percent sulfur and 61.0 API gravity (from Eastern Canada). Total imports of heavy crude from Canada are shown in Table 9 following.

TABLE 9: 2010 HEAVY CRUDE IMPORTS MILLION BARRELS IMPORTED IN 2010

KBD	Total Imports <25 API (KBD)	Canadian Imports <25 API (KBD)	% Canadian <25 API
PADD 1	127	7	6%
PADD 2	755	743	98%
PADD 3	2,356	117	5%
PADD 4	156	156	100%
PADD 5	373	52	14%
PADD 6	99	0	0%

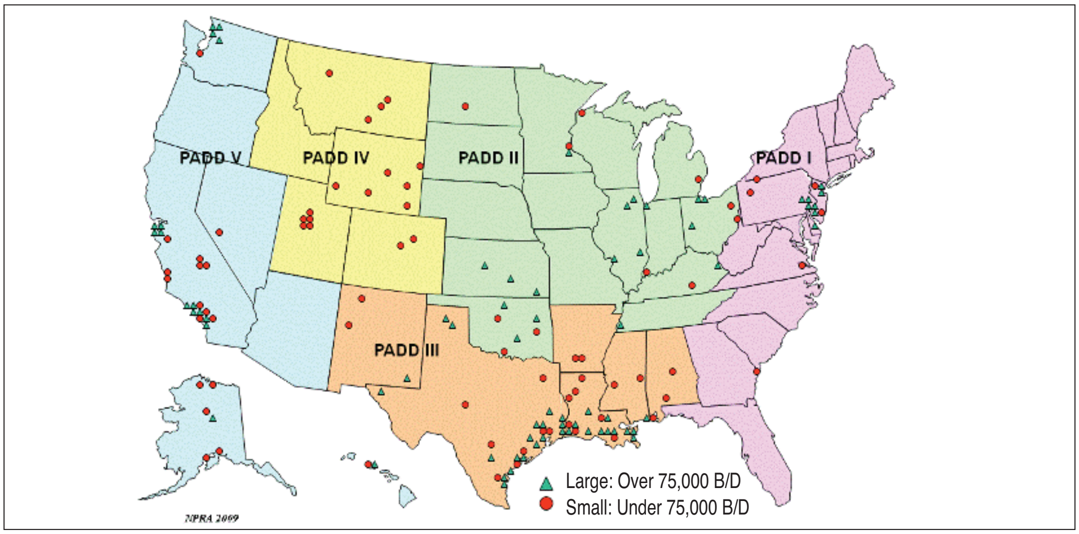
The capacity of US refineries to process heavy crude is not uniformly distributed. Similarly, the capacity for coking, a proxy for heavy processing capability, is not uniformly distributed; however, given the trend to heavier grades of oil from existing fields, additions of new coking capacity are planned in PADD regions 2 and 3 as shown in Table 10 below.

TABLE 10: US REFINERY UPGRADING CAPACITY (KBD)

KBD	Crude Capacity	Coking Capacity	Coking to Crude Ratio	Planned Coking Additions	Planned Coking Ratio
PADD 1	1400	94	7%		7%
PADD 2	3700	374	10%	147	14%
PADD 3	8600	1318	15%	225	18%
PADD 4	600	80	13%		13%
PADD 5	3200	530	17%		17%

The range of US refineries is shown in Figure 8, also illustrating the concentration of facilities in the South and Southern California regions.

FIGURE 8: LOCATION OF U.S. REFINERIES 2009



IV. US SYSTEM CAPACITY AND CONSTRAINTS

The PADD districts provide a useful framework to view a number of variables, including pipeline and processing capacity relative to regional demand. For the purposes of this report, they provide the descriptive and quantitative limits for handling current expansion of imports in the US for processing.

IV.a PADD Districts

PADD 3 is the largest US refining centre. As of year-end 2010, there were 54 operating refineries and more than 8.5 MBD of operable refining capacity, almost half of total US refining capacity, in PADD 3. In 2010 crude runs in PADD III averaged 7.6 MBD. The Midwest and West Coast have substantial refining capacity as well. The Midwest has 26 refineries and 3.7 MBD of refining capacity, while PADD 5 has 32 operating refineries and 3.2 MBD of capacity. Operable PADD 1 refining capacity has declined recently, dropping by 20 percent from 2009 to 2010 and it is likely to decline further. Both Sunoco and ConocoPhillips recently announced plans to sell or idle more than 0.5 MBD (combined) of PADD 1 refining capacity.

Crude oil processed in PADD 1 (East Coast) refineries is typically imported. PADD 1 is not connected to any crude oil producing regions of the US by pipeline[10], and other methods of shipping US crude to the East Coast are not economic.[11] In 2010 PADD 1 refineries imported 1.095 MBD of crude, vs. crude runs of 1.118 MBD likely drawn from inventory. The imported crude was mostly light sweet crude and was sourced mainly from Nigeria (35 percent) Canada (19 percent) and Angola (11 percent).

[10] United Refining in Warren, PA is connected by pipeline to Canada

[11] The Jones Act (Section 27 of the Merchant Marine Act of 1920 (P.L. 66-261)) requires that all goods transported by water between US ports be carried on American-flagged ships that were constructed in the US and that are owned by US citizens and crewed by US citizens and US permanent residents.

PADD 3 (Gulf Coast) is a major crude producing region and a major receipt point for imported crude. As a result, PADD 3 refineries process a mix of domestic and imported crude. In 2010, about 71 percent of the crude processed in PADD 3 was imported.

PADD 3 refineries are connected to onshore and offshore producing regions and PADD 2 and PADD 4 via an extensive pipeline network. These pipelines are used to aggregate crude from many producers to collection points, to move collected crude to centralized storage points, like Midland, TX and Cushing, OK, to deliver crude oil to refineries in PADD 3 and historically to move significant volumes of both domestically produced and imported crude oil from PADD 3 into the PADD 2 refining centres. More recently, due to increasing supplies of crude from Canada and the Bakken formation to the Midwest refineries, crude oil movements from PADD 3 to PADD 2 have declined considerably, and some historically south-to-north pipelines have reversed flow and now move crude the other way, from PADD 2 to PADD 3. EIA estimates that pipeline shipments of crude from PADD 2 to PADD 3 are now about 165 KBD, up 35 percent vs. early 2010. The EIA also notes that actual shipments of crude from PADD 2 to PADD 3 are likely higher than estimated because crude is now moving by rail and by truck out of Cushing, and the EIA does not collect data on truck and rail shipments. Although crude oil is moving south from PADD 2 to PADD 3, northward pipeline flows have not stopped. The Capline pipeline, which runs from St. James, LA to Patoka, IL and can move 1.1-1.2 MBD, continues to move crude to refineries in the Midwest, much of which is light sweet crude needed to balance heavier, sourer crude that is being supplied from Canada. Capline volumes have been recently estimated at well below capacity, largely for Valero's Memphis, TN refinery.

PADD 2 (Midwest) refineries processed 3.3 MBD of crude in 2010, of which 1.3 MB (40 percent) were imported, principally from Canada (~90 percent). PADD 2 refineries have historically been supplied by a mix of crude oil shipped via pipeline from storage at Cushing, shipped north via pipeline from the US Gulf Coast and inland from PADD 3 and imported via pipeline from Canada. As already noted, additional supplies from Canada and the Bakken formation have reduced the movement of crude from PADD 3 to PADD 2. Through the first six months of 2011, PADD 2 imports were up 14 percent vs. 2011, averaging 1.5 MBD. The increase is attributable to additional imports from Canada. In addition, PADD 2 crude production, mostly in North Dakota, has increased by 45 percent in the past decade, from 475 KBD in 2000 to 690 KBD in 2010. The increase in PADD 2 production combined with the increase in Canadian crude supply has significantly increased crude oil inventories at Cushing, OK.[12]

As noted earlier, the shipment of crude by pipeline, rail and truck from PADD 2 to PADD 3 is relieving congestion at Cushing. Much of the crude moving south is being shipped by rail to crude storage facilities in St. James, LA. Rail shipments of Bakken crude have increased dramatically in 2011 and are expected to continue increasing as additional crude-by-rail storage facilities are developed. Current shipments are estimated at 100 KBD, however the EIA does not track crude-by-rail movements and as a result, there is no official data available to verify the estimates. Some analysts expect that by year-end 2012, at least 300 KBD of Bakken crude will move to PADD 3 storage terminals in St. James, LA and Houston, TX. Others project more than 700 KBD of Bakken crude will move by rail to storage terminals in Oklahoma, Louisiana, Texas and California.[13]

[12] A detailed discussion of congestion at Cushing and the impact of increased supplies of Canadian and Bakken crude is included in the next section on crude flows in the US.

[13] P. 8, "Keystone XL Assessment — No Expansion Update," Ensys Energy & Navigistics Consulting, For the U.S. Department of Energy & the U.S. Department of State, *Final Report*, August 12 2011.

At present, PADD 2 is filled with Canadian heavy supplies, while extra refining/processing capacity exists in both PADD 3 and PADD 5. However, the Bakken[14] production increases, shown in Figure 9 below, are providing near-term competition for refining capacity, potentially displacing some current Canadian heavy crude.

FIGURE 9: NORTH DAKOTA CRUDE OIL PRODUCTION

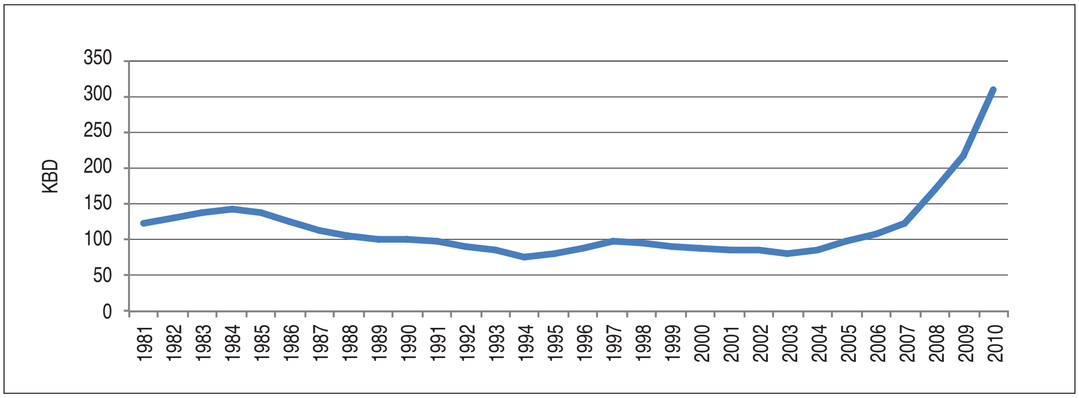


TABLE 11: PADD 2 FLOWS (MBD)

MBD	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Crude Inputs	3.410	3.309	3.218	3.224	3.301	3.314	3.309	3.238	3.244	3.153	3.305
Imports	.917	.906	.897	.957	1.069	1.006	1.130	1.129	1.188	1.204	1.314
Receipts from other PADD's	2.069	1.998	1.802	1.856	1.891	1.870	1.659	1.609	1.531	1.205	1.164
% Imports	27%	27%	28%	30%	32%	30%	34%	35%	37%	38%	40%
Production	.475	.458	.451	.442	.435	.443	.458	.470	.538	.591	.690

Historically, PADD 4 crude supply has been a mix of locally produced crude and imports from Canada, split about 50/50, and that trend continues. However, with increases in production from the Bakken Shale formation, PADD 4 shipments of crude to PADD 2 are increasing.[15]

PADD 5 (West Coast), which is logistically isolated from the rest of the US, is also supplied with a ~50/50 mix of locally produced and imported oil. In 2010 domestic production supplied 1.2 MBD, while imports amounted to 1.3 MBD. PADD 5 domestic crude production comes from Alaska (49 percent) and California (51 percent). Alaskan crude (largely Alaska North Slope) is medium sour crude with API gravity of 28-32 degrees and sulfur of 0.9 Wt. percent, and is delivered to refineries in California and Washington State. California crude is heavy sour crude — and as a result California refineries have considerable upgrading capability. Imports into California in 2010 were mainly medium to heavy sour crudes, principally from Saudi Arabia, Ecuador and Iraq. Imports into Washington were mostly from Canada (65 percent) ranging from light sweet to heavy sour, and secondarily a mix of medium and heavy sweet and sour from Angola. As noted, California is logistically isolated; however, crude could move by rail into California from storage locations in western PADD 4 that could be supplied by pipeline from Canada.

[14] A detailed discussion of congestion at Cushing and the impact of increased supplies of Canadian and Bakken crude is included in the next section on crude flows in the US.

[15] P. 8, "Keystone XL Assessment — No Expansion Update," Ensys Energy & Navigistics Consulting, For the U.S. Department of Energy & the U.S. Department of State, *Final Report*, August 12 2011.

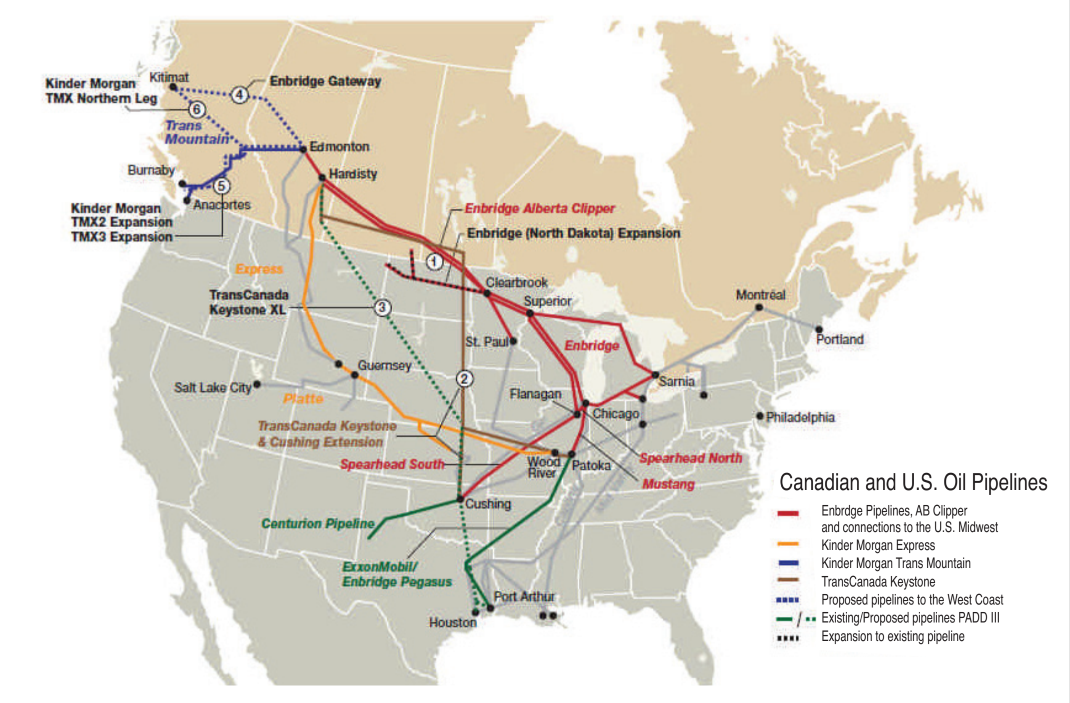
TABLE 12: SUMMARY OF PADD DISTRICT FLOWS

PADD	2010 Crude Input MBD[16]	2010 Imports MBD	Imports as a % of Total Crude Input
1	1.106	1.095	99%
2	3.305	1.314	40%
3	7.642	5.400	71%
4	0.542	0.345	64%
5	2.582	1.361	53%

IV.b North American Future Infrastructure Investments

A number of infrastructure investment projects to improve crude flows within the US, within Canada and from Canada to the US have been announced or discussed. Each could have a significant impact on the supply/demand balance in Cushing, either directly or indirectly, and each could open new markets for Canadian crude or crude from the Bakken and Eagle Ford shale formations. A summary of pipelines proposed for development or expansion is shown in Figure 10 following.

FIGURE 10: EXISTING AND PROPOSED CANADIAN AND US PIPELINE CAPACITY



Source: Canadian Association of Petroleum Producers, "Outlook for Canada's Oil and Gas Industry," June 2011

[16] "Gross Input to Atmospheric Crude Distillation Units," US Energy Information Agency, *Refinery Utilization and Capacity*.

Keystone Pipeline XL: TransCanada has proposed to build a 1,600-mile, 36-inch crude pipeline that would move between 500 KBD and 900 KBD of crude oil from Alberta to the Gulf Coast. It would begin at Hardisty, AB, extend southeast through Saskatchewan, Montana, South Dakota and Nebraska, incorporate part of the existing Keystone pipeline Phase II that runs through Nebraska and Kansas to Cushing, and then extend on to Nederland, TX, which is adjacent to the Port Arthur, TX refining centre.

TransCanada has secured long-term contracts to move 380 KBD of crude from Hardisty to the USGC. The Canadian National Energy Board approved the pipeline in March 2010 and construction has started on the Canadian side of the border, but not on the US side. The pipeline, which would cross an international border into the US, requires a Presidential Permit from the US Department of State and that permit has not yet been issued. Keystone XL has faced considerable opposition and preventing it from being built has become a cause célèbre among environmental groups, think tanks and lobbyists. Final hearings for the permit were scheduled to end in Washington, DC on October 7, 2011. TransCanada expects a decision by 2012. If the permit is granted and construction can begin in 2012, TransCanada expects that Keystone XL could be operational in 2013.

Wrangler Pipeline: In late September 2011, Enbridge Inc. and Enterprise Partners L.P. announced the formation of a joint venture to build the Wrangler pipeline, a 500-mile interstate pipeline, beginning at an Enbridge terminal in Cushing and extending to the Enterprise ECHO Terminal in southeast Houston. The proposed common-carrier pipeline will have a capacity of 800 KBD of crude and a second phase of the project will extend an additional 85 miles from ECHO Terminal to near Port Arthur, TX. Wrangler has an in-service target date of mid-2013.

Keystone XL is intended to ship heavy oil while Wrangler is intended to ship light crude; consequently they should complement each other. Enbridge is also in discussions with US and Canadian East Coast refiners about reversing the flow of a pipeline that runs from Quebec to Ontario, to move light crude from North Dakota (Bakken), from Texas (Eagle Ford) and Colorado to refineries on the East Coast. The line could be operational as early as 2014.[17]

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[17] Other current or proposed projects which would impact flows and capacity include:

- BP is upgrading its Whiting, IN refinery to increase heavy crude processing capacity by 260 thousand barrels per day (KBD) and plans to replace current inputs of WTI crude with WCS;
- Valero recently completed projects at its Port Arthur refinery that expanded coker, crude and vacuum unit capacities and is also working on the construction of a 50 KBD hydrocracker. These projects will allow the refinery to process 100 percent sour crude oil and up to 80 percent heavy sour crude;
- Total recently completed a deep conversion project at its refinery in Port Arthur, including a coker, a vacuum distillation unit and a hydrotreater that will expand the refinery's ability to process heavy and sour crude oil;
- Motiva Enterprises, a joint venture between Shell and Saudi Aramco, expects to complete a major expansion project at its Port Arthur refinery in 2012. The project will increase the crude processing capacity to 600 KBD and will expand the refinery's capability to process heavier slates of crude.

There are worldwide changes in capacity that would affect the price of Canadian products, especially those in Asia. Here, numerous refinery upgrades and new refinery projects have been announced, including:

- A joint venture between PetroChina and PdVsa to build a 200 KPD refinery that will process heavy Venezuelan crude oil;
- Fujian Refinery and Petrochemical Limited, a joint venture between the province of Fujian, Sinopec, Saudi Aramco and Exxon Mobil, to build a refinery that will process heavy sour crude from Saudi Arabia;
- A greenfield refinery to be built by Sinopec in Quanzhou that will have significant upgrading capability, including a coker, fluid catalytic cracker, hydrocracker and hydrogenation units and that will process Kuwaiti sour crude;
- Sinopec has also signed a memorandum of understanding with Saudi Aramco to enter into a joint venture to build a world-class, full-conversion refinery in Yanbu, Saudi Arabia that will process 400 KBD of Saudi crude.

Other refinery upgrade projects:

- Repsol expects to complete upgrading at its Petronor and Cartagena refineries that will add a total of 93 KBD of coking capacity;
- Chinese Petroleum Corp. is planning to add desulfurization capacity at its Kaoshiung refinery in Taiwan with an anticipated completion date of 2013.

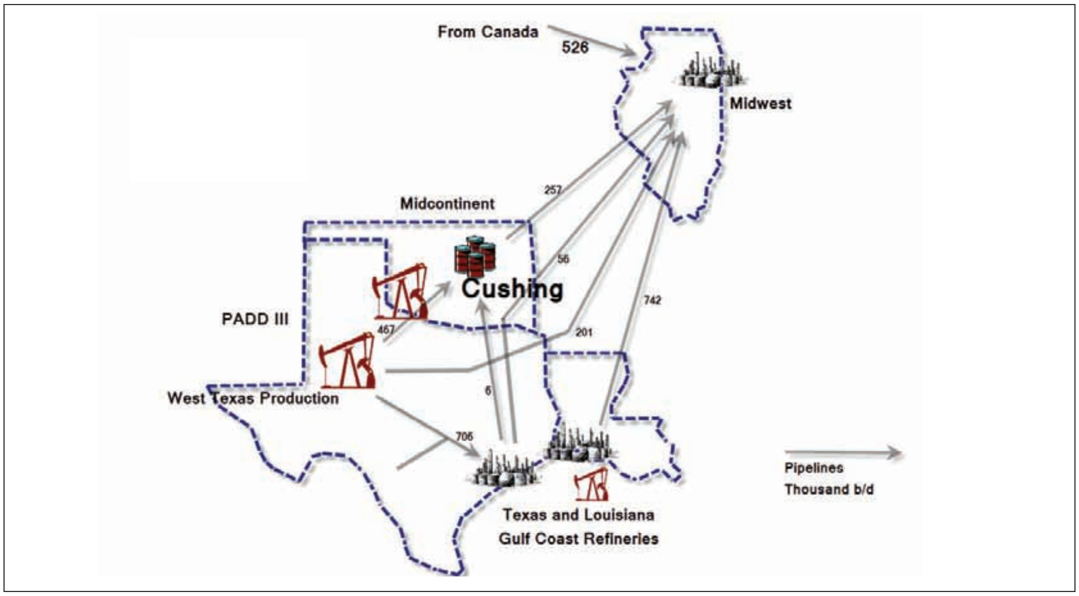
Seaway Pipeline: The Seaway pipeline connects the Houston area with Cushing and is designed to move imported crude oil north to the Cushing distribution node. The line is jointly owned by ConocoPhillips and Enterprise Partners. ConocoPhillips has recently announced an interest in selling its share of this pipeline to Enbridge, which could permit reversal of the line from Cushing to Houston.

V. CRUDE FLOWS INTO THE US: CONSTRAINTS AND FORECAST

In the last three years, additional imports of Canadian crude into PADD 2 and PADD 4, combined with increased production from the Bakken formation, have significantly affected crude flows in the US. Pipeline flows in some cases have been reversed, construction of additional pipeline and storage capacity is being considered, and modes of transportation that were considered prohibitively expensive, like rail and truck, are becoming economic alternatives to move crude beyond the pinch points of a currently overwhelmed logistics system.

Historically, the extensive crude oil pipeline system that serves the Gulf Coast and the Midwest, PADDs 2 & 3, moved crude from the producing regions in West Texas and Oklahoma to refineries on the Gulf Coast and in the Midwest. Crude-gathering pipelines linked production locations to collection points and additional pipelines linked collection points with major storage locations in Cushing, OK and Midland, TX. Pipelines moved crude out of Midland and Cushing to refineries in Louisiana and Texas on the Gulf Coast and to refineries in Oklahoma, Kansas — the midcontinent— and to refineries in the Midwest served by the pipeline hubs in Patoka and Chicago, IL. Figure 11 illustrates the pipeline flows circa 1988, when crude imports from Canada into the Midwest totaled 526 KBD. The numbers reflect volumes shipped rather than pipeline capacity.

FIGURE 11: PIPELINE CAPACITY FLOWS AS OF 1988



Source: Energy Policy Research Foundation presentation at CERI Conference, April 2011.
Info from CME Group and Purvin and Gertz Study

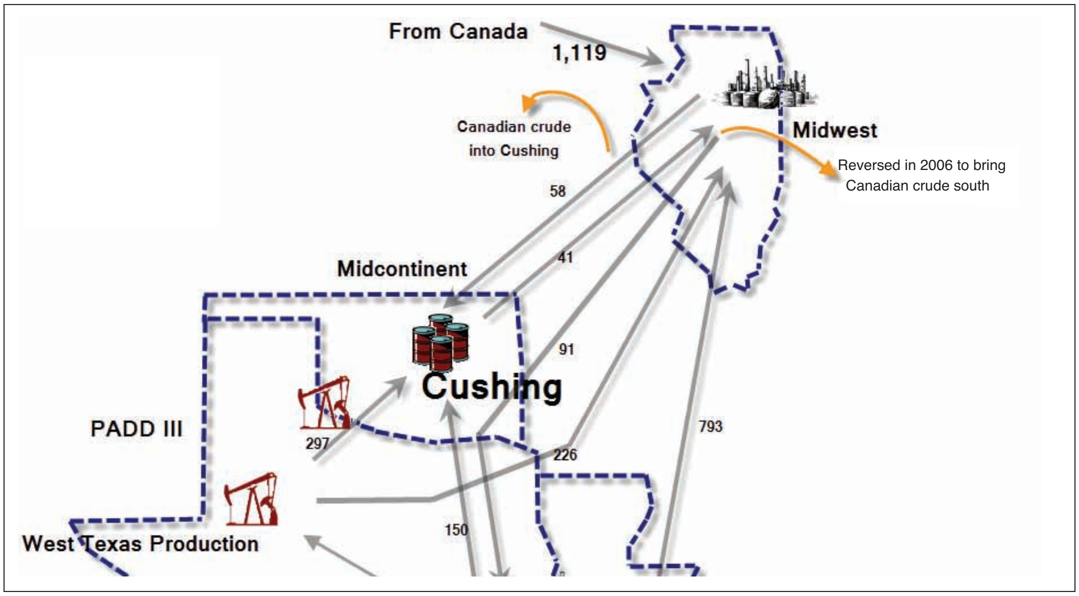
Table 13 describes the flows of crude in and out of the Cushing hub. The changes since 1988 clearly mark the shifts in markets worldwide, with the highest volume shifts occurring in the US Midwest.

TABLE 13: VOLUMES IN AND OUT OF CUSHING

From	To	1988	2008	1998-08 Change KBD	1998-08 Change %	Comments/Changes Since 2008
Canada	Midwest	526	1119	593	113%	Keystone, Alberta Clipper have streamed
West Texas	USGC	706	42	(664)	-94%	Long Horn reversal to bring WTI to Houston
West Texas	Cushing	467	297	(170)	-36%	
West Texas	Midwest	201	226	25	12%	
Cushing	Midwest	257	41	(216)	-84%	
Midwest	Cushing	0	58	58	n/a	
Midwest	Texas USCG	0	91	91	n/a	ExxonMobil pipeline reversal from Texas to Illinois
Texas - USGC	Midwest	56	0	(56)	-100%	ExxonMobil pipeline reversal from Illinois to Texas
Louisiana - USCG	Midwest	742	793	51	7%	
Midwest	Louisiana USGC					Barge movements down the Mississippi are increasing
Texas - USGC	Cushing	6	150	144	2400%	Probably near zero now because WTI cheaper than LLS

By 2008, crude imports from Canada into the Midwest had doubled to 1.1 MBD, offsetting declining US domestic production that once shipped from West Texas to Cushing and on to the Midwest. In addition, pipeline capacity that had once moved crude from Corsicana, in east Texas, to Patoka, IL (Pegasus pipeline) had been reversed to enable Canadian crude to reach refineries in Texas, while pipeline capacity that had once moved crude oil from Cushing to the Midwest had been reversed to move Canadian crude beyond Chicago to storage at Cushing (Spearhead). Finally, Seaway, a new 30-inch line that runs north from Freeport, TX, to Cushing had begun operations and was moving 150 KBD of crude from the USGC to Cushing.

FIGURE 12: PIPELINE FLOWS AND CAPACITY AT 2008

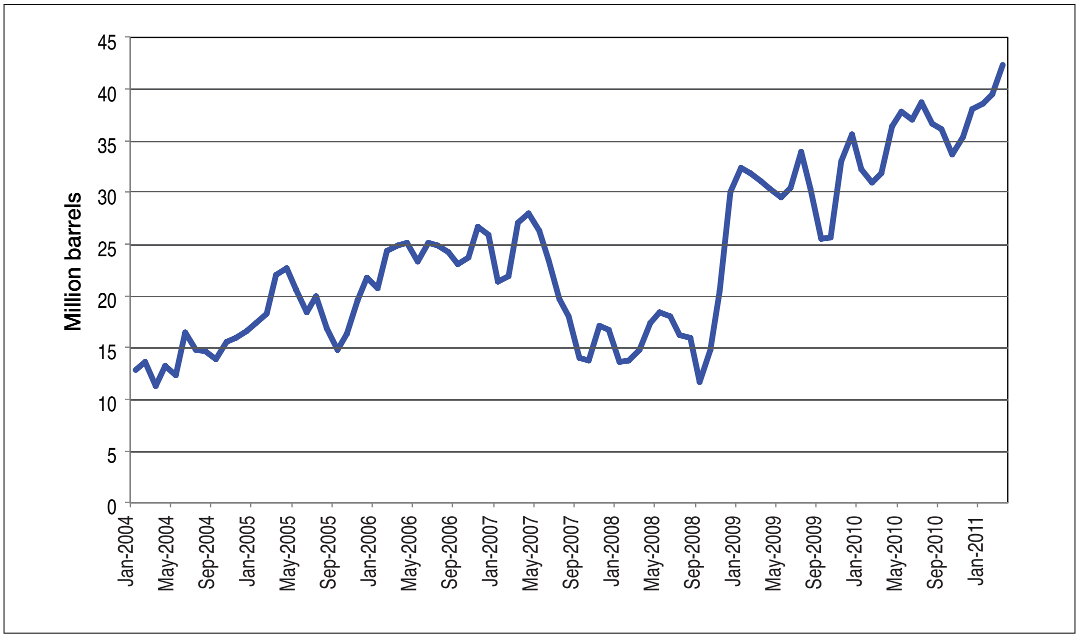


Source: Energy Policy Research Foundation presentation at CERI Conference, April 2011. Info from CME Group and Purvin and Gertz Study.

Since 2008, additional pipeline capacity has come on stream. TransCanada completed the Keystone pipeline in early 2011. Keystone runs from Hardisty, AB to Steele City, NB where it divides. One section goes on to Patoka and Wood River, IL and the other to Cushing storage. The Keystone pipeline has a capacity of 590 KBD. Enbridge's Alberta Clipper pipeline runs from Hardisty to Superior, WI. The Alberta Clipper has a capacity of 450 KBD (with potential expansion to 800 KBD) and connects to existing Enbridge pipelines in Wisconsin and on to Chicago, eventually connecting with Enbridge's Spearhead system that moves crude to Cushing. The Alberta Clipper line began operating in mid 2010.

Shortly after the Alberta Clipper and Keystone pipelines became operational in late 2010/ early 2011, crude inventories in Cushing started to build, which should have been expected, given the increase in capacity to move crude into Cushing without a similar increase in capacity to move crude out of Cushing. The upshot is a constraint in capacity, which limits the volume of crude with characteristics similar to Canadian products. By March of 2011, nearly 86 percent of Cushing's 48 MB of operational storage had been filled.

FIGURE 13: CUSHING INVENTORY



V.a Historic Impact of Cushing Constraints on Crude Prices: WTI, LLS and Brent

Cushing is a logistics hub for US crude, historically a gateway for regional supply. Logistics hubs typically have substantial storage capacity and are characterized by transportation interconnections that often include various forms of transportation, like pipelines, rail and trucking. The supply/demand balance in a hub dictates price levels in the region surrounding the hub and as a result, also defines price differentials between hubs.[18]

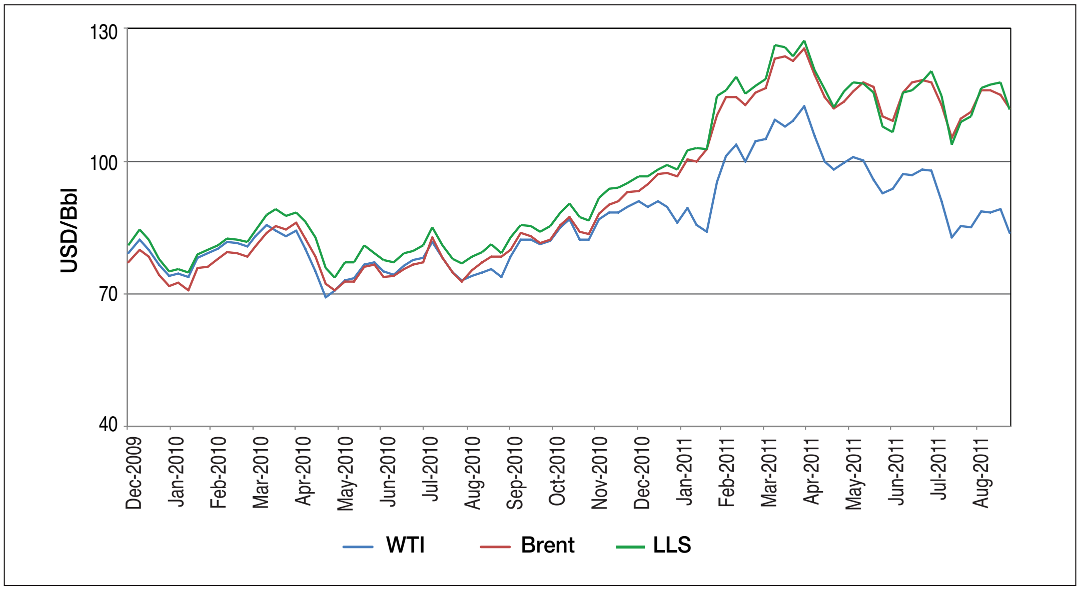
When inventories of crude build at Cushing, the price of West Texas Intermediate crude or WTI, the benchmark crude that is delivered at Cushing, tends to decline relative to the price of crude in other regions, or hubs, such as Louisiana Light Sweet that is traded in the US Gulf, and Brent that is physically traded in the North Sea. Brent is also the major benchmark for pricing crude oil delivered to Europe and for certain crudes delivered to the US. Both Louisiana Light Sweet and Brent crudes are similar in quality to WTI.[19]

The discount from Brent to WTI and LLS can be clearly seen in the period 2009 to 2011 captured in Figure 14 following.

[18] "How Pipelines Make the Oil Markets Work — Their Networks, Operation and Regulation," Allegro Energy Group, Trench, Cheryl J., President, December 2001.

[19] LLS is 0.4 percent sulfur with an API gravity between 34-41; WTI (futures contract) is 0.42 percent sulfur with 37-42 degrees API, and Brent is .25 percent sulfur with 38 API

FIGURE 14: BRENT VS. LLS VS. WTI 2009 TO 2011



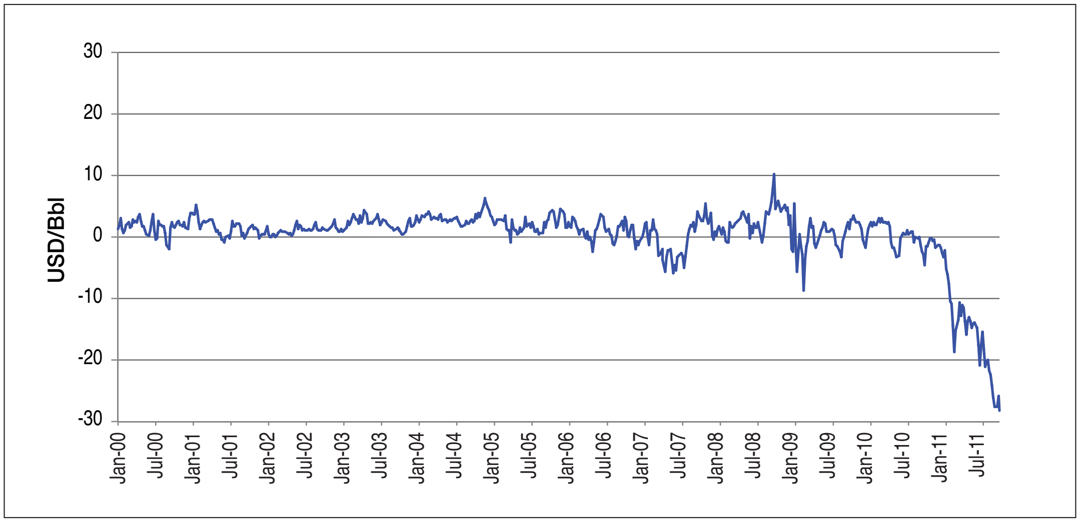
The historically higher prices of WTI and LLS reflect their lower sulfur levels and the fact that, to be competitive with WTI and LLS, Brent had to be lower priced FOB Sullom Voe so it would arrive in the USGC at a comparable price to WTI and LLS. Historically WTI and LLS have traded at a $1.50-$2.00 premium to Brent, reflecting the cost to ship Brent from Sullom Voe to the USGC. From time to time, however, regional supply/demand imbalances, as well as the volatility of freight costs[20] have altered that historical relationship. For example, in 2007 the price of WTI slipped below the price of Brent when unplanned refinery outages in the US Midwest reduced crude demand and caused inventories at Cushing to build. That deviation from the historical relationship between prices corrected fairly quickly. However, in 2008, when the US economy slowed and energy demand in the US declined, WTI prices again came under pressure relative to Brent prices. Europe was moving into recession as well, but Brent prices were less affected because Brent was (and is) more globally traded than WTI. Unlike WTI, for which the physical market is limited to the US, Brent crude can follow demand and physically move to markets outside Europe, such as Asia.[21]

The direct discount and performance of WTI to Brent is graphically illustrated in Figure 15 following, with dramatic changes occurring post-2008.

[20] "The WTI/Brent spread began to expand over the 2003 to 2005 timeframe as a result of several factors, including increases in freight. In fact, the extensive volatility of the relationship through that period and beyond to the most recent periods can at least be partially explained by this freight volatility. Typically, commentary regarding this relationship rarely includes a proper attribution to the freight cost changes that directly impact the netbacks for Brent deliveries into the USGC." Purvin & Gertz, "The Role of WTI as a Benchmark," January 2010.

[21] BNP Paribas, "Oil Market Comment: Déjà Vu, Of WTI Contangos and Brent Spreads," January 28, 2009, Tchilinguirian, H.

FIGURE 15: DIFFERENCE IN PRICE BRENT – WTI



In the second half of 2008, hurricanes bumped up WTI prices relative to Brent prices; in 2009, the price of WTI slipped well below that of Brent when inventories at Cushing climbed above 30 MB. Crude oil prices had declined dramatically during the second half of 2008, falling more than $100/bbl, and the WTI market had slipped into steep contango, reflecting a market sentiment that prices would return to higher levels within months. As a result, inventories at Cushing climbed dramatically and the price of WTI declined.

Throughout 2009 and 2010, the relationship between WTI and Brent oscillated in a range of +/-$5, reflecting regional shifts in supply/demand balances. Crude inventories at Cushing moved up and down as well, but remained above historical levels, reflecting the additional supplies of Canadian and Bakken crude. Then, early this year, with additional Canadian crude from TransCanada's Keystone pipeline and Enbridge's Alberta Clipper reaching the US Midwest, crude inventories at Cushing began to climb yet again, and WTI prices quickly began to decline. At the same time, the price of Brent was being pushed higher by loading disruptions in the North Sea and Africa and the impact of the Arab Spring on the global crude market. By February the price of WTI had fallen to almost $20 below Brent.

Crude inventories in Cushing peaked at more than 40 MB in March of 2011 and have since declined to 30 MB as crude moves out of Cushing storage by rail and by truck, and Bakken crude moves by rail to the USGC. However, the WTI/Brent spread continued to widen, peaking at more than $28 in mid-September. As of October 2011 the spread is WTI $23 under Brent.

There has been considerable discussion and speculation about the magnitude of the WTI/Brent spread and the reasons(s) the spread has remained wide despite the drop in Cushing inventories.[22] In addition to congestion at Cushing, which has been resolved, the reasons cited include:

[22] Refer to Appendix for a list of papers, articles and blog posts discussing the WTI/Brent spread.

- Brent is a more global cargo-traded crude and as a result, reacts to global geopolitical events like the Arab Spring, while WTI does not;
- Regional disruptions in supply have put upward pressure on North Sea crudes and crudes that price on a Brent basis;
- Differences in the term structure of WTI and Brent markets. Brent is backdated while WTI is in contango in the market;
- Speculative investment in the market, especially the ICE futures market, that has supported Brent prices and perhaps put downward pressure on WTI futures prices;
- Market perception about the regulatory hurdles that must be cleared for additional pipeline capacity to be constructed;
- Some pipelines and refineries are owned by the same companies, which prefer not to reverse pipelines from Cushing to the Gulf Coast, since it is preferable for them to buy WTI at lower prices.[23]

Each of these circumstances could have contributed, and may still be contributing, to the relative weakness in the price of WTI versus Brent. Given that the weakness developed when increased flows of Canadian and Bakken crudes reached the markets in the US Midwest, it is fair to say that the increase in supply into Cushing without a similar increase in the flow of crude out of Cushing has been a major factor. It is also apparent that WTI prices are likely to remain depressed relative to other global crudes until crude can economically move out of a regionally oversupplied market into a global market.

For example, the current wide spread does reflect the much higher cost to move an incremental barrel of crude to the USGC by rail or by truck, and may also reflect a scarcity of both incremental rail and truck transportation. The EIA tracks neither data on crude shipments by rail and truck, nor data on the availability of such shipping capacity. As a result, no official data on rail or truck shipments is available, though anecdotal information suggests that crude trucking capacity that normally serves California has been rerouted to the Midwest. At the same time though, because the cost to ship crude by rail or by truck is considerably less than the current $23 spread,[24] the cost to move the last barrel does not totally explain or account for the spread.

Crude oil price levels and price differentials have varied greatly since 2000 averaging about 22 percent during the last decade but falling to 10 percent and lower since 2010. In our analyses we assume proportions to remain relatively constant with the magnitude of the differential fluctuating with oil prices. Current price differentials are likely to persist whether WTI falls to $65/bbl or remains above $100/bbl. High oil prices certainly add more impetus to increasing exports and collecting higher differentials but it is also possible that prices could fall so low that production and pipeline capacity expansions would be deferred.

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[23] This condition is dynamic and subject to change.

[24] Stillwater estimates the cost to ship long distance by unit train at $6/bbl and by manifest car at $10/bbl.

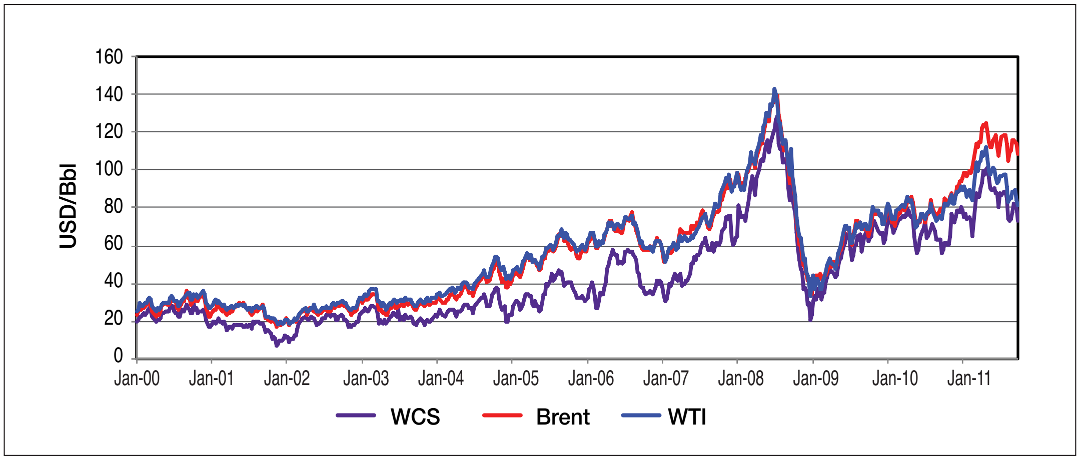
V.b Price Levels

We have developed price models to illustrate WCS, WTI, Brent and LLS prices for comparable quality blends. Since the market value of crude oil is based on the market value of derivative products into which it can be refined, e.g., gasoline, jet fuel and diesel fuel, the cost to refine the crude oil into products (a function of the *quality* of the crude), plus the cost to transport it, determine the price from production location to refining location. Prices for various crude oils are determined by comparison to the price of some benchmark crude or blend, such as WTI. This reflects the fact that liquid and transparent trading based on the benchmark crude supports open-market price discovery.[25]

CRUDE PRICING: WESTERN CANADIAN SELECT

Figure 16 illustrates the price of Western Canadian Select (WCS) crude, FOB Hardisty, relative to the prices of WTI and Brent. WCS currently prices based on WTI because it is delivered into a market for which the historical benchmark blend is WTI. WCS prices at a discount to WTI because it is a lower quality crude (3.51Wt. percent sulfur and 20.5 API gravity) and because it must be shipped from Alberta to the US Midwest to reach the refinery market.

FIGURE 16: WCS PRICING RELATIVE TO WTI AND BRENT



When WCS is compared directly to WTI, the volatility of pricing is clearer, affected largely by supply and pipelines issues. This is clearly illustrated in Figure 17 following.

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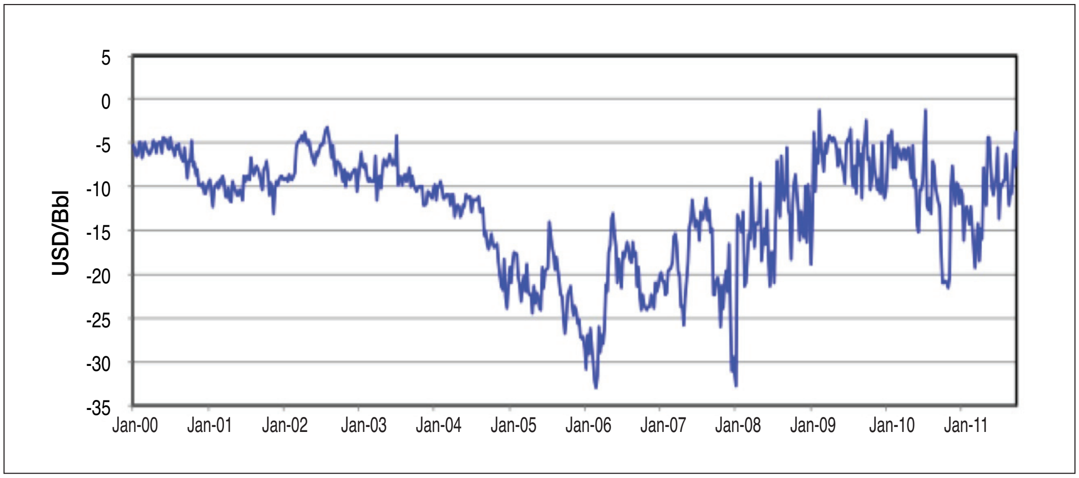
[25] WTI evolved as the benchmark crude in the US because WTI and crudes of similar quality were once produced in significant volumes in Oklahoma, Kansas and Missouri, as well as Texas and were gathered, collected and stored in Cushing. When the NYMEX introduced a crude oil futures contract, Cushing was chosen as the delivery location for the contract because it was a significant storage location and delivery point for US domestic crude oil. The NYMEX decision to link the crude oil futures contract to crude oil delivered at Cushing solidified WTI's position as the benchmark crude in the US. More recently, because of the persistent discount of WTI relative to other global crudes, WTI's effectiveness as a benchmark has come into question. Nonetheless, WTI continues to be used as an international pricing benchmark, "because of its relative liquidity and price transparency." (The Role of WTI as a Benchmark," Purvin & Gertz, January 2010, p.5.)

FIGURE 17: WCS DISCOUNT TO WTI



The significant decline in the price of WTI relative to other crudes prompts the question as to whether WCS is trading at below fair market values from its linkage to WTI or because it is delivered into a capacity constrained US market.

If WCS were selling at below fair market value, demand for WCS would outpace supply, which has not been the case. Currently there is little, if any, incremental demand for WCS in the US Midwest because Midwest refineries are maximizing the amount of WCS they can process, although there are several upgrading projects underway that will increase processing capability.

The challenge for WCS is to access additional markets where there is additional demand, or where market value is higher, and such markets could be inside as well as outside the US. Generally speaking, however, since crude oil value is partially a function of the cost to move crude oil from production location to refining location, markets that require less transportation, typically geographically closer markets, offer a higher realized price, all else being equal.

If WCS could be delivered into the US Gulf Cost or West Coast markets,[26] it would dramatically increase demand for WCS — the USGC and USWC have substantial capacity to process heavy sour crudes like WCS — and would offer an opportunity to price WCS relative to other crudes that are supplied to refineries in those markets, like Maya or Kern River, or using indices, like the Argus Sour Crude Index.[27] However it's important to note that if WCS can be delivered to USGC refineries, so can other crudes stored at Cushing, which would close the gap between the price of WTI and the price of other US crudes, like LLS, and would affect global crude prices as well. Essentially crude is no longer stranded at Cushing and is available to the global market.

[26] The Low Carbon Fuel Standard adopted as part of AB32 in California increased the cost of refining High Carbon Intensity Fuel Oils, which include crude oils produced from oil sands formations. However, there are questions about the viability of the LCFS and as a result, California may become a viable market for WCS

[27] The Argus Sour Crude Index is calculated based on the prices of three medium sour crudes that are produced and actively traded in the USGC: Mars, Poseidon and Southern Green Canyon. Saudi Aramco, Kuwait Petroleum and Iraq's Somo use the Index to price crude sold into the US.

WCS OPPORTUNITIES OUTSIDE THE US

While the USGC and USWC markets are proximate and both can process heavy sour crude, concern has been expressed by various Canadian oil producers about stagnating demand for petroleum products in the US, both on a short-term basis due to a still weak US economy, and on a longer-term basis, given the US focus on alternatives to petroleum-based fuels.

China, on the other hand, has experienced explosive economic growth and doubled energy consumption in the past 10 years, and as a result has been suggested as a lucrative market for WCS. It is reasonable to note that Chinese expansion rates have slowed and are not likely to experience historic rates of expansion again in the near term.

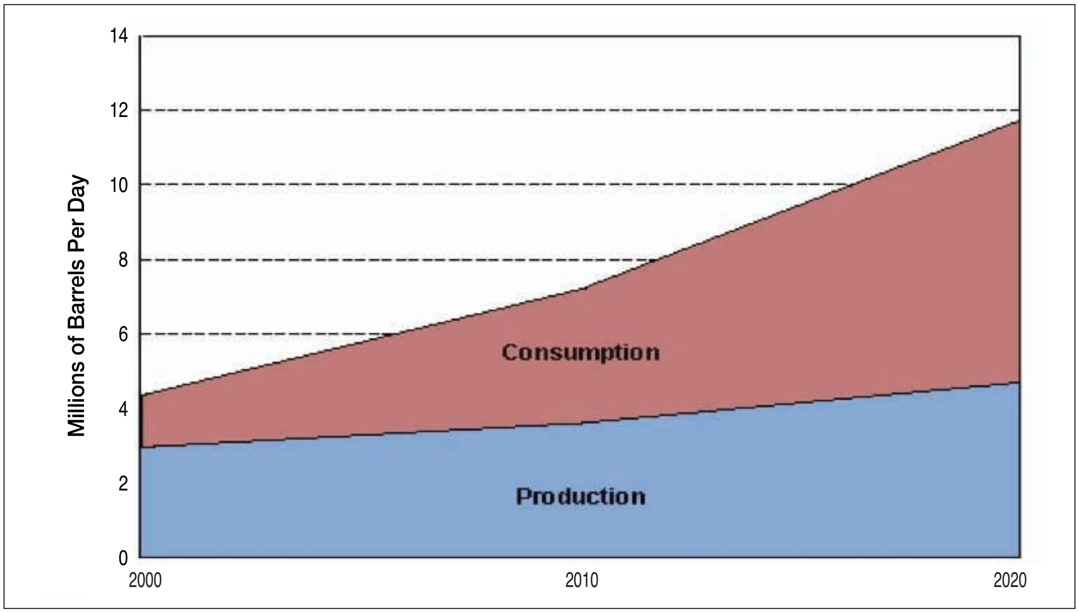
TABLE 14: RELATIVE FLOWS CHINA VS. US AND WORLD OIL IN MBD

Country/Region	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
China	4.80	4.92	5.16	5.58	6.44	6.70	7.26	7.53	7.82	8.32	9.19
United States	19.70	19.65	19.76	20.03	20.73	20.80	20.69	20.68	19.50	18.77	19.18
World	76.78	77.51	78.16	79.71	82.53	84.06	85.13	85.81	85.30	84.33	87.08

In addition, both PetroChina (CNPC) and Sinopec have invested in the Canadian oil sands, and about 50 KBD of oil sands crude is currently finding its way to China via Canada's West Coast. According to the US EIA, Sinopec and CNPC control 85 percent of the oil refining capacity in China.

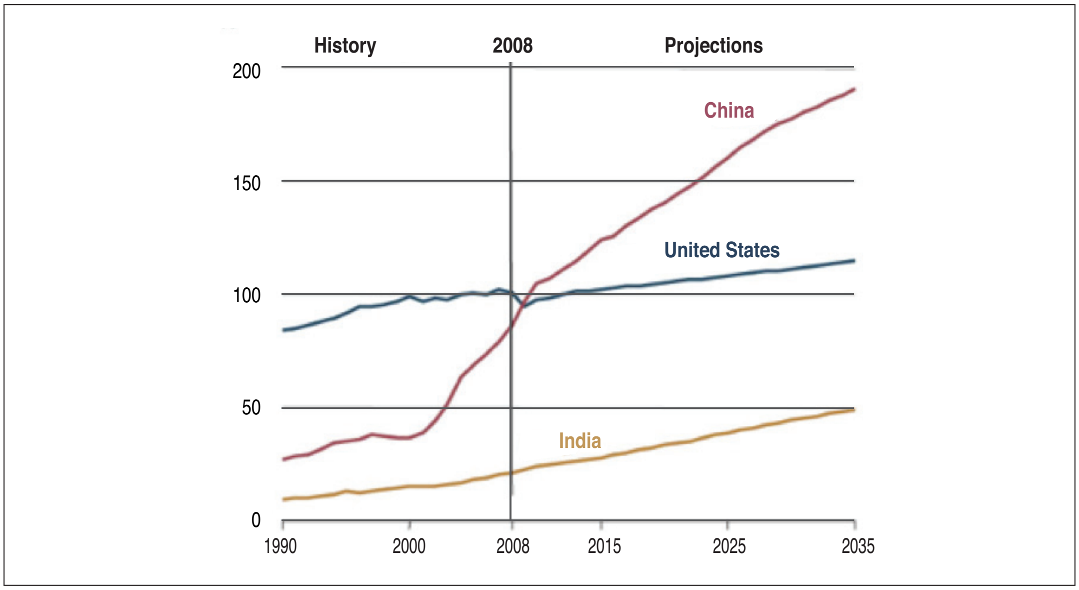
The US EIA (see Figure 18, 19) has forecast that China will consume 9.6 MBD of liquid fuels in 2011 and 17 MBD by 2035. By 2035, overall energy consumption in China is expected to far outpace that of the US.

FIGURE 18: CHINESE DEPENDENCE ON IMPORTED OIL



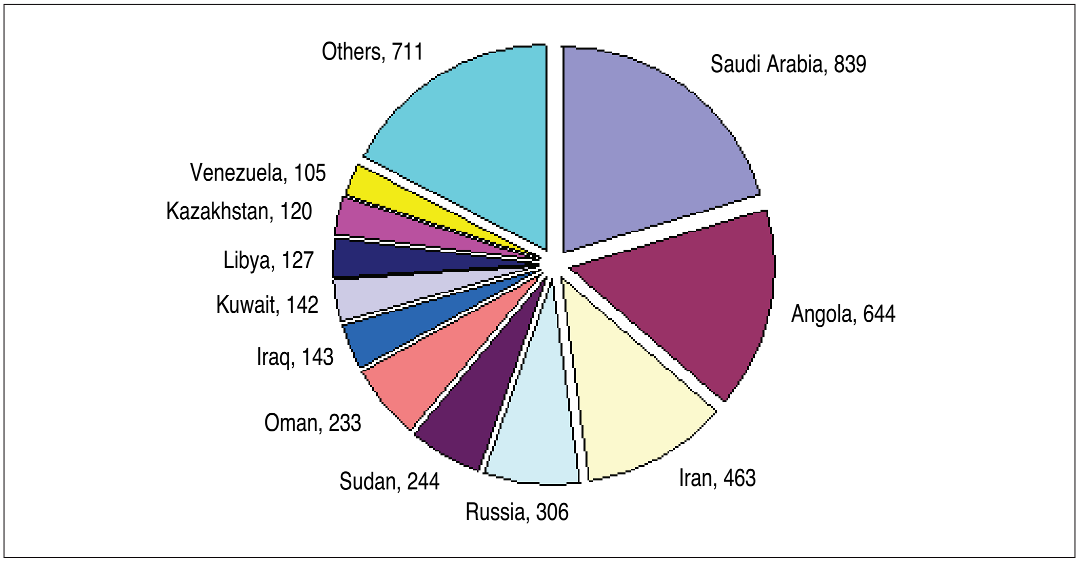
Source: Development Research Center, The State Council, China's National Energy Strategy and Policy 2000-2020.

FIGURE 19: ENERGY CONSUMPTION IN THE UNITED STATES, CHINA AND INDIA, 1990-2035 IN QUADRILLION BTU



China's oil production is expected to reach 4.2 MBD in 2011 — leaving a shortfall of 5.4 MBD to be filled by imports.[28] Historically the shortfall has been covered with imports from a variety of producing countries. Currently Saudi Arabia and Angola are the largest suppliers of imported crude into China.

FIGURE 20: CHINA'S CRUDE OIL IMPORTS BY SOURCE 2009



Source: FACTS Global Energy

The EIA has reported that China has been steadily increasing its refining capacity to meet the growth in demand. China's crude refining capacity is estimated at 9+ MBD and is expected to increase to 12+ MBD by 2015 if all goes as planned. China has joint ventures with national oil companies from Kuwait, Saudi Arabia, Russia, Qatar and Venezuela to build new refineries.

[28] US Energy Information Administration, Country Analysis Brief, China, November 2010.

The EIA expects China to diversify their supply going forward to meet the demand of more sophisticated refineries. Historically, most Chinese refineries were built to handle heavy but relatively sweet crude oils (e.g. Daqing and other domestic crudes); however, Chinese refiners are reported to be investing in the upgrading capacity necessary to accommodate sour crudes from the Middle East. China will also need to invest in infrastructure to process high-acid crude oil from Bohai Bay. China already processes high-acid Dar Blend crude from the Sudan.

Western Canadian Select crude will have to be priced competitively to crude supplied to China from other sources. Arab Heavy crude delivered to Asia sees a price discount relative to the average of Dubai and Oman crude prices as published by Platts, the benchmark for crudes delivered into Asia.

In theory, a price for WCS into China that would be competitive to Saudi crude could be calculated by determining the landed price of Saudi crude in China — Dubai/Oman Average plus the premium plus the freight — and then netting back that landed price to Kitimat or other Canadian ports by subtracting the freight cost from the appropriate Chinese port to Kitimat, adjusting for quality differences between WCS and the Saudi crude and then subtracting the transportation costs from the production area, e.g., Hardisty, to Kitimat. This would produce an FOB Hardisty price for WCS going to China that could be compared to the WTI-based FOB Hardisty price.

EnSys Energy and Navigistics Consulting, in their August 2011 report for the US Departments of Energy and State,[29] estimated the costs to move Dilbit from the production fields in Alberta to China, as shown in Table 15 following.

TABLE 15: DILBIT PRICES TO FOREIGN MARKETS

Crude Stream	Route	Est. Freight $/Bbl.	Basis
Dilbit	Trans Mountain to Vancouver, Aframax to China	$7	Expansion at Westridge to take Suezmax tankers would reduce freight by ~$0.50/Bbl.
DilBit	Northern Gateway to Kitimat, tanker to China	$7	Basis is VLCC
DilBit	Rail to Kitimat, tanker to China	$7 - $9	70-75% bitumen, 25-30% diluent
Bitumen	Rail to Kitimat, tanker to China	$8 - $11	Raw bitumen

All via BC Coast and on to Asia

EnSys had concluded in an earlier study undertaken for the US Department of Energy that "… Asia constitutes the major region for future petroleum product demand and refining capacity growth and offers Canada diversification of markets." EnSys went on to state that "…. if the access routes are developed, [Asia] could absorb at least 1 MBD of WCSB crudes, potentially significantly more; this versus the less than 50,000 bpd of WCSB crude that moves to Asia today."[30]

[29] "Keystone XL Assessment — No Expansion Update," Ensys Energy & Navigistics Consulting, For the U.S. Department of Energy & the U.S. Department of State, *Final Report*, August 12 2011.

[30] "Keystone XL Assessment," Prepared by Ensys Energy For the U.S. Department of Energy Office of Policy & International Affairs, *Final Report*, December 23 2010.

It is worth noting that Saudi Aramco and other large national oil companies price crude using destination-specific benchmark prices. Saudi crudes that move to Europe are priced using a formula that is based on a weighted average of Brent futures prices, the so-called Bwave, as are crudes from Kuwait and Iraq. The Bwave Index or Brent Weighted Average Price Index is the average price of all trades for a particular futures contract calculated for each business day. As was already mentioned, Saudi crude destined for the US prices on the basis of the Argus Sour Crude Index.

Mexican crudes also price based on regional benchmarks and are close to WCS quality levels. FOB prices for Maya, Isthmus and Olmecca to the different markets are calculated according to the following formulas in Table 16:

TABLE 16: MEXICAN CRUDE PRICING DISCOUNTS FOR QUALITY

To: US Gulf Coast:	To: Europe	To: Asia
Maya: 0.4(WTS + USGC No. 6 3%S) + 0.1(LLS + Dated Brent) +/- constant [31]	Maya: 0.527(Dated Brent) +0.467(No.6 3.5%)-0.25(No.6.1%-No.6 3.5%) +/- constant	Maya: (Oman + Dubai)/2 +/- constant
Isthmus: 0.4(WTS+LLS) + 0.2(Dated Brent) +/- constant	Isthmus: 0.887(Dated Brent) +0.113(No.6 3.5%)-0.16(No.6.1%-No.6 3.5%) +/- constant	Isthmus: (Oman + Dubai)/2 +/- constant
Olmeca: 0.333(WTS+LLS + Dated Brent) +/- constant		

Source: Platts Methodology and Specifications Guide to Crude Oil, June 2011, Constants are defined and published by Pemex.

VI. CANADIAN EXPORT OPPORTUNITIES

Oil products reflect worldwide demand, adjusted for quality and transportation costs. Thus, a crude product with light sweet characteristics will trade interchangeably with similar products no matter what the region of origin, after accounting for transport, tariffs and upgrading necessary to prepare it for shipment. In this sense, the price of a barrel of oil is perfectly fungible and reflects the marginal demand of consuming nations or regions. The product can trade locally, regionally or internationally, but in the most general terms, is considered a world product. Various markets typically utilize various benchmarks for pricing blends that reflect the desirability and value of characteristics of refineries available for processing.

Hogan[32] notes that, "The essential international character of an oil stockpile derives from the inherent fungibility of oil in the world oil market. Net inventory transactions in any country are intended to translate into net changes in the demand for imports, which realigns the availability of oil for all consumers; hence, the use of an oil stockpile anywhere affects supply everywhere."

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[31] The assessment is for barrels commonly sold FOB Dos Bocas and FOB Cayo Arcas with API gravity of 22 and sulfur content of 3.3 percent.

[32] Hogan, William W. (1983) "Oil Stockpiling: Help Thy Neighbor," *The Energy Journal*, 4:3:49-71.

No matter what the source of crude oil, its price ultimately reflects this "world market" characteristic. Canadian supplies are not different, after accounting for the fact that Canada is a net export market and reflects the characteristics of a price-taker. As NRCan notes, "supplies of light sweet crude oil are decreasing and the differential between heavier and more sour crudes is increasing. Using cheaper heavier crude oil means more investment in upgrading processes. Costs and payback periods for refinery processing units must be weighed against anticipated crude oil costs and the projected differential between light and heavy crude oil prices."

Canadian refiners face a dual issue. Since their export market is dominated by a single buyer, the market price they see is that of a price-taker, a condition exacerbated by a limited ability to ship directly to world markets without transiting the US. The comparative advantage lies in having vast reserves to serve that market, especially as regional reserves in the US, such as Kern, decline with corresponding idle processing capacity without new imports.

According to the NEB, the price of crude oil is most commonly quoted in $US per barrel. Traditionally, the US has been Canada's main export market and, usually, Canadian crude oil is priced relative to the crude oil benchmark West Texas Intermediate (WTI), at Cushing, OK.

VI.a Canadian Refining Capacity

Most refineries in Western Canada and Ontario were designed to process the light sweet crude oil that is produced in Western Canada. Unlike leading refineries in the US, Canadian refineries in these regions have been slower to reconfigure their operations to process lower cost, less desirable crude oils, instead choosing to rely extensively on the abundant, domestically produced, light sweet crudes. As long as these lighter crudes were available, refining economics were insufficient to warrant new investment in heavy oil conversion capacity[33].

However, with growing oil sands production and the declining production of conventional light sweet crudes, refineries in Western Canada and Ontario have started to make the investment required to process the increasing supply of heavier crudes. Much of this investment by the large integrated oil companies (companies that are involved in both the production of crude oil and the manufacturing and distribution of petroleum products) is associated with ensuring a market for their growing oil sands production.

In Western Canada and Ontario, almost 50 percent of the crude oil processed by refiners is conventional light sweet crude oil and another 25 percent is high-quality synthetic crude oil. Synthetic crude is a light crude oil that is derived by upgrading oil sands. Most of the remaining crude oil processed by these refineries is heavy, sour crude. The crude slate is expected to change significantly in the years ahead as refiners increase their capacity to process heavy crude oil and lower quality synthetic crudes.

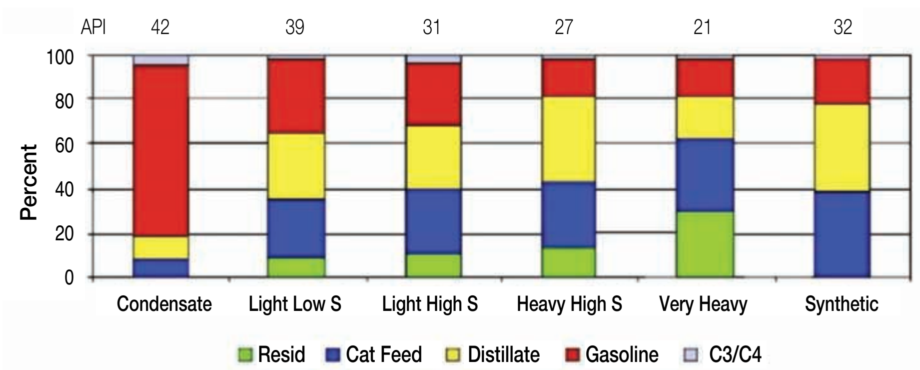
Refineries in Atlantic Canada and Quebec are dependent on *imported* crudes and tend to process a more diverse crude slate than their counterparts in Western Canada and Ontario. These refiners have the capacity to purchase crude oil produced almost anywhere in the world and therefore have incredible flexibility in their crude buying decisions. Approximately one-third of crude processed in Eastern Canada and Quebec is conventional, light sweet crude and

[33] NRCan, 2009, www.nrcan.gc.ca/energy/sources/petroleum-products-market/1519.

another one-third is medium-sulfur, heavy crude oil. The remaining one-third is a combination of sour light, sour heavy and very heavy crude oil. The crude slate in Eastern Canada is expected to remain much more static than that in Western Canada and Ontario, as these refiners are not constrained by the quality or volume of domestic crude production.

The product yield for six typical types of crude oil processed in Canada is illustrated in figure 20 below. It includes both light and heavy as well as sweet and sour crude oils. A very light condensate (62 API) and a synthetic crude oil are also included. The chart compares the different output when each crude type is processed in a simple distillation refinery. The output is broken down into five main product groups: gasoline, propane and butane (C3/C4), Cat feed (a partially processed material that requires further refining to make usable products), distillate (which includes diesel oil and furnace oil) and residual fuel (the heaviest and lowest-valued part of the product output, used to make heavy fuel oil and asphalt).

FIGURE 21: COMPARISON OF REFINERY YIELDS BY CRUDE TYPE



Source: NRCan, 2010

All crude oil is not valued equally. Light oil that is low in sulfur (sweet) is more valuable to refiners than heavy oil with higher sulfur content (sour). Canadian producers market a wide range of crude oils, ranging from heavy sour bitumen blends from Alberta's oil sands to pentanes plus (C5+) primarily obtained from natural gas. The difference in value between light and heavy oil (the differential) is primarily determined in the market for each type. In general, a widening of the differential leads to poorer profitability for Canadian heavy oil producers.

Virtually all of Canada's oil production moves to refining centres in the US or Canada via pipeline and most originates in Alberta. According to CERI, between 10-15 percent in any given year is not exported. The two primary distribution centres in Alberta are located near Edmonton and Hardisty that provide the price point for WCS as a crude benchmark. To match increasing production, various pipeline capacity additions have been proposed. As pointed out in NEB filings,[34] an expansion of the Corridor Pipeline will increase capacity by 26,200 m^3/d (165 KBD) in 2010 beyond the capacity indicated in the filings of the Gateway project, where

[34] Gateway project application, Table 1-2,Pipeline Capacity for Oil Production to Edmonton and Hardisty, Muse-Stancil, 2010, NEB.

from Edmonton and Hardisty, three major trunk-lines and three smaller pipelines transport crude oil to domestic and export markets. At Edmonton, crude oil is transported east on the Enbridge Mainline system, west on Kinder Morgan's Trans Mountain Pipeline Limited (TMPL) and south through Pacific Energy Partner's Rangeland Pipeline system. At Hardisty, crude oil can travel to PADD IV and PADD II on the Enbridge Mainline system, Kinder Morgan's Express Pipeline, or through the combination of Inter Pipeline Fund's Bow River and Plains Marketing's Milk River pipelines. The Enbridge Mainline system and Express Pipeline provide the largest export capacity to North American mid-continent markets, while the TMPL system is the only pipeline that can currently access markets on the west coast.

VI.b Canadian Export Potential:

In this report, Canadian export potential is expressed as a hypothetical outcome, considering current limited access to tidewater shipping points. For instance, the completion of the proposed Gateway pipeline would enable a substantial increase in *market opportunity*, beyond the current processing capacity and demand from US markets. These are summarized below in Table 17 following:

TABLE 17: FUTURE CANADIAN OIL MARKET POTENTIAL

Market	Potential
Asian markets including China, Japan, South Korea and Taiwan.	Current crude oil imports in these countries totaled 1,756,000 m^3/d (11,045 kbpd) in 2008.
Japan	Japan is the largest importer of crude oil in Asia. In 2008, crude imports were 664,000 m^3/d (4,180 KBD), nearly 90 percent of which came from the Middle East.
China	In 2008, China imported 570,000 m^3/d (3,600 KBD) of crude oil, which represents an annual increase of 14 percent since 2003. As Muse Stancil[35] points out, most capacity is in coastal refineries with an estimated capacity of 569,000 m^3/d (3,580 KBD) today.
South Korea	Total imports in 2008 were 376,000 m^3/d (2,360 KBD), and approximately 60 percent of these imports originated in the Middle East.
US West Coast	On the US West Coast, three refining areas are accessible by tanker. These centres are the Puget Sound area of Washington, the San Francisco area and Los Angeles. The Puget Sound refineries can process Canadian crude oil delivered by pipeline (the Trans Mountain Pipeline), whereas deliveries to California are made by ship.
Puget Sound	Refining capacity in Puget Sound is approximately 99,060 m^3/d (623 KBD). Imports represent about 40 percent of total refining capacity, and remaining refinery needs are being satisfied by domestic Alaskan North Slope (ANS) production delivered via tanker.[36]
California	California is the third-largest consumer of transportation fuels in the world. It has 21 refineries that process over 317,975 m^3/d (2,000 KBD) of crude. The two main refining areas in California are the San Francisco area and Los Angeles. Both have access to waterborne supply, as well as pipeline connections to state production. In 2008, California state production accounted for 38 percent of its total refinery supply. California's domestic crude oil is predominantly heavy in quality, and in many aspects is similar in character to Canadian heavy crude oil.

[35] Muse Stancil, op cite, 2010

[36] ANS production has been in decline for several years. In the last five years, production has decreased by 32,000 m^3/d (200 KBD). Production forecasts indicate that this trend is likely to continue, with expected annual decreases of about three percent until 2021. As in Puget Sound, refineries in California also process ANS crude. This accounted for about 13 percent of total supply in 2008.

The majority of the forecast future demand is represented by Asian markets, where according to Muse Stancil, total potential demand exceeds 110,000 m3/d (690 KBD) with over half estimated to be for the heavier grades of Canadian crude. The breakdown of Asian market potential is shown in Table 18 following.

TABLE 18: FORECAST NORTHEAST ASIAN DEMAND

Country	KBD
Japan	99,800
Northern China	64,000
Southern China	34,100
South Korea	53,300
Taiwan	27,500
Total	278,700

Source: Muse Stancil, NEB filing 2010

On the West Coast, demand for the heavier crude grades has been generally growing in the California market for a number of years, mostly due to the decline in California heavy crude production.

VII. PRICING BENCHMARKS AND HISTORICAL TRENDS

Canadian crude oil is designated WCS or Western Canadian Select, a heavy oil that trades based on a variety of indices either directly or as a ratio with other blends. We correlated the price of this commodity with a range of other oil or oil blends in order to determine which world market index most closely characterized WCS on world markets or in US trading as a basis for comparison. These are shown in Table 19 following, where each crude type is represented by API, sulfur content, average spot FOB, the differential over the period 2007-2009 for WCS and the 2007 to 2011 correlation coefficient with WCS.

WCS has historically traded based on WTI, and in fact royalty rates in Alberta are based on this association. Based on the high correlation with WTI[37] (0.95 or 95 percent of the difference is explained by substituting WTI for WCS on the world market after adjusting for quality differences).

[37] LLS represents a reasonable alternative in this case, but is not widely used in other markets.

TABLE 19: CRUDE OIL STREAMS EVALUATED FOR COMPUTING PRICE DIFFERENTIALS

Crude Type	API	Sulfur	Country
Heavy Crudes			
Western Canadian Select, Hardisty	22.0	3.05%	Canada
Daqing	27.0	0.10%	China
Cano Limon	29.2	0.50%	Colombia
Oriente	24.1	1.51%	Ecuador
Sidi Kerir Iran Heavy	31.5	1.80%	Iran
Maya	21.8	3.33%	Mexico
Arab Heavy	27.7	2.87%	Saudi Arabia
Alaska 1st Purchase	30.0	1.10%	US
Kern	18.0	1.20%	US
Bachaquero 17 1997 Only	17.0	2.30%	VZ
Mars	30.3	1.91%	US
Intermediates			
Fateh	31.0	2.00%	Dubai
Global Average Export Weighted	avg	avg	Global
Brent	38.0	0.37%	UK
US Average Import Weighted	avg	avg	US
WTI[38]	40.0	0.42%	Cushing
WTS	32.8	1.98%	Midland
LLS	47.7	.31%	St. James
Saudi Medium	30.2	2.59%	Saudi Arabia
Canadia Par 40	40.0	0.50%	Canada

Source: Platts, US EIA

Over the past two years, world oil pricing has increasingly turned to Brent as a standard benchmark. WTI currently trades at a discount to Brent, which is incorporated in this analysis as a reference as well (correlation is 0.92); the differential here is expected to diminish over the next five years.

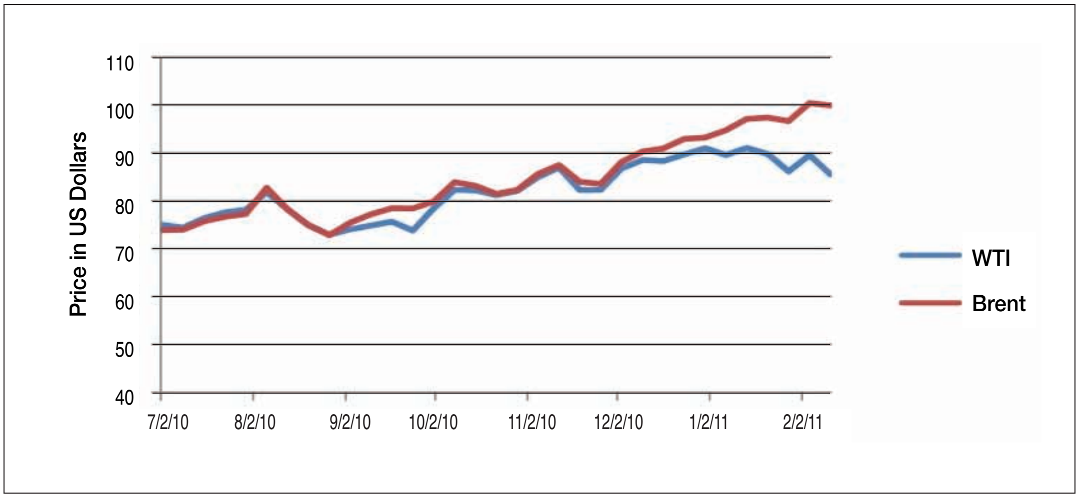
Until very recently, West Texas Intermediate (WTI) and Brent prices saw a diverging spread as shown in Figure 21. In large part this reflects the fact that the Midwest region is oversupplied with Canadian imports, and the fact that crude oil is currently difficult to move as far as the Gulf Coast. The final shipping from Cushing to Gulf Coast refineries is accomplished by rail and truck, adding up to $14.00 per barrel with handling. This is largely due to inadequate pipeline capacity to the Gulf Coast past the Midwest region. Recently, additional shipments from the Bakken formation (both PADD 2 and PADD 4) have also contributed to the oversupply.[39]

[38] Intermediate has various definitions depending on the source. Two of the crudes included in this list are commonly referred to as light crudes in the US — WTI and LLS(Light Louisiana Sweet). CME specifications for WTI delivered at Cushing: Sulfur: 0.42 percent or less; API gravity: not less than 37 degrees, nor more than 42 degrees. According to Platts Crude Oil Specification Guide, the price assessment for Light Louisiana Sweet (LLS) is for barrels delivered to St. James, LA with API gravity between 34-41 degrees and sulfur content of 0.4 percent.

[39] The WTI/Brent spread has started to compress and as of early November is ~$17 today. In addition, much of the oversupply in the US Midwest/midcontinent results from Canadian imports which are much more significant in volume than Bakken production, especially as much Bakken crude is now moving directly to the USGC by unit train, bypassing Cushing.

The spread is a relatively recent event, where the gap between Brent and WTI prices began in December 2010, and has widened considerably in 2011.

FIGURE 22: WTI, BRENT PRICE COMPARISON



Source: US DOE, EIA 2011 SEO

There are current projects that will affect changes in overall capacity in the US Midwest region. Two key pipelines (Seaway — 430 KBD capacity and Capline — 1.2 MBD capacity) bring oil *north* from the Gulf to the Midwest. This has created a conflict between oil moving north from the Gulf (imports) and oil from the North (including Canada) that tends to create excessive supply for refineries.[40] The result has been a lower price for WTI-priced crude at Cushing. Canadian crude characteristics are desirable, however, given current refinery characteristics and heavy crude capacity as well as demand. However, demand for output (in the form of derived products including gasoline and diesel fuel) from the refineries remains high in spite of long term softening of demand, so prices remain relatively high and stable, even while prices for crude oil are low. The situation[41] is desirable for refiners, who have can change in the face of shifts in market conditions, such as reversing flows on individual pipelines.[42]

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[40] Why are WTI and Brent Prices so Different?,Tverberg, G., http://ourfiniteworld.com/2011/02/19/why-are-wti-and-brent-prices-so-different/

[41] Both Seaway and Capline have been running below capacity. Capline volumes are estimated at ~300 to 400 KBD vs. capacity of 1.2 MBD. Some lighter, sweeter crude is also moving up Capline to balance WCS-changing market conditions in terms of supply.

[42] On Nov. 2, 2011, Enterprise Products Partners announced they were considering new options to move the glut of crude oil landlocked in Oklahoma down to Gulf Coast refineries via the 350 KBD Seaway pipeline, which carries crude from the Gulf of Mexico area to the Midwest. Conoco had been seen to be reluctant to change the direction of the pipeline because it supplies its 187 KBD refinery in Ponca City, OK. The joint Enterprise/Enbridge Wrangler project proposes a 36-inch pipeline to carry crude from Enbridge's Cushing terminal down to the Gulf Coast following existing pipeline corridors. The Enbridge system currently carries crude from oil sands in Alberta to Chicago and then onto its 190 KBD Spearhead system from Chicago to Cushing. High demand for space on the line has led to shipments being restricted to about 16 percent of what is nominated.

Ultimately, lower prices may alter the volume from the Gulf region, resulting in some short-term capacity release. Much of the end product transfer (the marginal barrel moved from Cushing to the Gulf Coast, is moving by rail and truck, which adds to the overall cost, making northern products relatively less attractive. This shipping cost adds costs to the marginal barrel that may range from 10$US to 15$US, depending on refinery location. We estimate the cost of shipping crude from Cushing to the coast is $10/barrel by truck and up to $6/barrel by train.

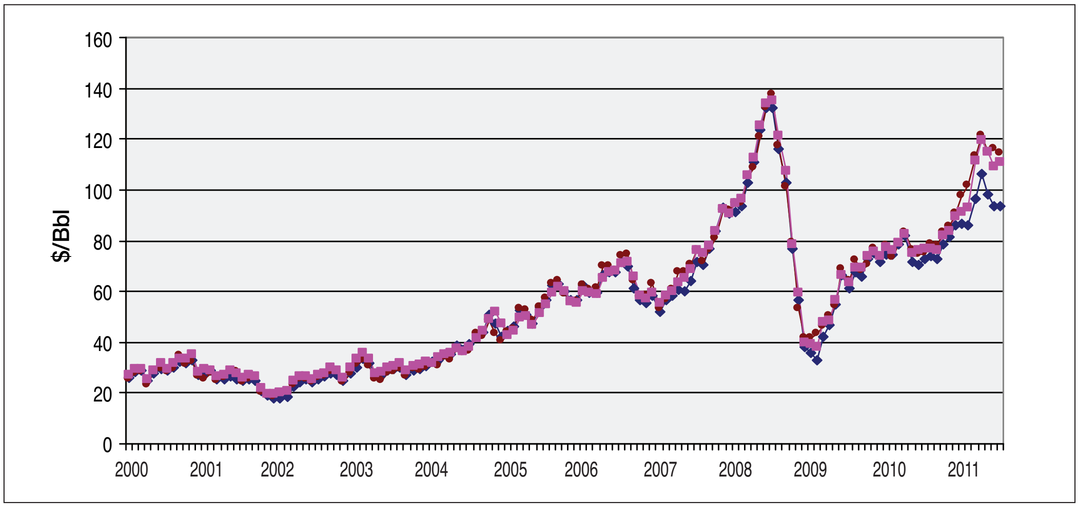
Refineries are the normal source of crude oil demand, and when at full capacity, bids for new supply in the absence of competitive short-term storage can be expected to fall. The counterpoint to this can be found in the futures market, where demand may be seen to rise, reflected in long-term bid prices, which is similar to the pattern that has developed for WTI.

In the face of continuing market demand, the most efficient, and most likely solution for easing the constraints and resultant price differential, will be additional pipeline capacity that will remove the current inefficient rail/trucking pattern from Cushing to the Gulf Coast. We believe a solution to this will occur by 2016. We assume this will allow crude from Canada to be absorbed by PADD 3 and 5, making the price equivalent for WCS very close to Maya, and priced at LLS levels at the Gulf Coast.

Short-term relief could also occur if either of the southern pipelines is reversed (as pointed out earlier, refiners have limited incentive to undertake this reversal at the present time given the crack spread or difference between crude and derivative product prices). Conversely, if the selling price of crude oil in the Midwest remains depressed over time, sellers will find other markets for their crude oil, and the southern pipelines bringing oil up from the Gulf will operate at reduced capacities.

Ultimately, the price *differential* at Cushing and at the Gulf Coast will diminish (ignoring transportation costs) for crude adjusted for quality differences. We expect the resulting price differential to decline between Brent and WTI to between $10 and $15 barrel by 2016. At some point in the future, which we assume will occur by 2020, the price of Brent is likely to close down toward equilibrium with LLS, which will still maintain a quality differential to the reference blend, and correspondingly with WCS as shown in Figure 23. We expect WTI to fall from its current marker prominence by 2020. Governments such as Alberta with a royalty charge may seek equivalency or adopt an alternative index in this event.

FIGURE 23: MONTHLY AVERAGE PRICE DIFF WITH WCS TO 2011



VIII. FUTURE PRICE DIFFERENTIALS

Canadian crude oil is primarily exported to the US via pipeline, with minor amounts shipping to the US West Coast via Vancouver. In this report, the basis for pricing Canadian exports is the benchmark of WCS priced at Hardisty.[43] Canadian crudes in the form of WCS are characterized as heavy (22 degrees API and 3.05 percent sulfur content). It is priced with a corresponding discount for quality based on the processing characteristics of the regional market in which it is delivered. In addition, transportation costs must be assessed to the point of delivery, in order to establish equivalency to competitive products based on world market prices.

We have estimated the equivalent value of WCS heavy oil in potential export markets in order to calculate the opportunity cost represented by sales to a single client country (the US). We then compare this to potential sales on the world market.

Measuring this difference depends on adopting an equivalent heavy-blend proxy currently available on the world market. This difference should appropriately reflect discounts for quality to which we can add an appropriate shipping distance charge. This analysis relies on reference prices from 2001 to present and forecasts volumes and prices to 2030.

Current market prices are based on Brent and WTI as benchmarks and are assumed to prevail until 2015, at which point we assume the bottleneck at Cushing is removed. Our proxy world price is Louisiana Light Sweet (LLS) after 2016. The discount for quality of WCS then is established using a differential of Maya[44] to LLS at the marginal refiner in Port Arthur, TX. The difference in value of the product slate produced from Maya or WCS relative to LLS has fallen below 10 percent recently and this percentage might fall even further in the near future.

This results in the assumption of no change in the relative netback to Canadian producers during the period 2011 to 2015, beyond which point we assume that the Cushing refinery constraint is lifted, either through the construction of the Keystone XL pipeline or a suitable series of smaller, incremental pipeline additions that effectively eliminate the transportation charge for rail and truck transfer of the last barrel to Gulf Coast refineries.

By 2016, we assume Gulf Coast access is available for WCS, and we can use a pricing differential based on LLS as the world price, with a quality discount that matches LLS to Maya. Consequently, there are two distinctly different pricing regimes for Gulf Coast access, namely the present time to 2015 and 2016 through 2030.

There are important shipping alternatives proposed that might alter market conditions. These include pipeline additions from Alberta to the British Columbia coast, and the Hardisty-to-Gulf Coast addition of the Keystone XL pipeline. Access for Canadian heavy crude to West Coast ports through new capacity on the BC coast is not likely to occur before 2020.

[43] Alternative Canadian oil prices are available at Edmonton, but for purposes of this report are not included in the comparison of world price differentials.

[44] Maya has the closest correlation coefficient to WCS trading characteristics. The monthly fixed differential provided by PEMEX accounts for changes in the refiner margin. The Maya price, however it is derived, is regarded as the benchmark heavy sour crude price on the USGC.

We estimate that future pricing differentials in these cases will still be based on LLS, with a quality discount derived from the same marker of Maya. Current capacity in PADD 3 and PADD 5 will accommodate significant increases in shipped quantities of this product. California, as well as China, will be an important source of demand for these additional supplies. Should West Coast ports be available, we estimate that the decline in Kern production can be accommodated by refiners who currently process crude of approximately the same quality as expected oil sands shipments.

BENCHMARK OF LLS

The export market potential for expanding Canadian crude oil exports within and beyond North America is assessed by first examining selected historical crude oil spot market FOB prices for major benchmarks and determining the closest proxy for the blend of Canadian heavy oil shipped at Hardisty. We have assumed spot market prices FOB, averaged annually, as the most reasonable choice, since they are reported according to known and similar methodology, publicly available and are comparable for pricing other crude oil streams.

As a base, the total price differential or *TPD*, for WCS at Hardisty, $WCS_{(H)}$, is defined as the arithmetic difference between WCS and an equivalent crude oil product P_B priced at the same point in time:

$$TPD = P_B - WCS_{(H)}$$

These total differentials, expressed as monthly averages, are then adjusted for quality differences and transportation costs to specific points of sale in each potential export market. The total differential is also adjusted for quality differences among benchmarks to arrive at an expected netback[45] price for WCS at Hardisty. The average relationships of quality and transportation price adjustments to specific benchmarks or a basket of benchmarks are extrapolated into the future.

The export market potential[46] is included in the netback price of WCS at Hardisty and defined for our purposes as being equal to the price of the benchmark (PB) adjusted for quality and sulfur content (QF) plus the transportation charge (T) from Hardisty to each benchmarks' reference point of delivery.

$$WCS_{(H)} = P_B * (1-QF_{\%}) - T_{\$/bbl}$$

This potential represents, after adjustments, the assumed revenue potential for each barrel shipped to tidewater ports at a price equal to the world spot market price at that moment. No adjustment is made for increased costs of pipeline transport beyond an assumed distance calculation.[47]

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[45] A summary of all the costs associated with bringing one unit of oil to the marketplace, and all of the revenues from the sale of all the products generated from that same unit. The netback is calculated by taking all of the revenues from the oil, less all costs associated with getting the oil to a market. These costs can include, but are not limited to, importing, transportation, production and refining costs and royalty fees.

[46] In public discussions, the total price differential, commonly a comparison between WCS and Brent, is used to characterize potential lost revenues to Canadian producers caused by a lack of access to export markets beyond North America. A better measure of export potential is probably the netback price, although a heavily regulated entity or a state-owned enterprise might offset or recapture additional transportation and upgrading costs of lower grade crudes by regulating prices in domestic markets.

[47] For access to Asian and West Coast markets, figures for pipeline costs are assumed from documents filed with the NEB.

PRICE SERIES USED FOR COMPUTING DIFFERENTIALS

Several crude oil price series were available based on the basis of statistical similarity, geographical proximity to market and public availability to serve as reference points for this study. Benchmarks like Brent, West Texas Intermediate (WTI) and Louisiana Light Sweet (LLS) each have advantages for comparison because the quoted market price is net of any other transportation expense incurred by the supplier to get it the geographically referenced point of sale — Sullom Voe, Cushing and St. James, respectively. The price series for LLS is a keystone for bridging comparisons from mid-continent North America crude oil prices where WCS is currently being shipped, to Europe and beyond.

All the data used for computing price differentials and making comparisons among global crude oils were taken directly from the US Energy Information Administration's (EIA) published spot market price series from January 2000 to present. Each EIA dataset consists of monthly average spot market prices FOB that are net of transportation costs to the refiner and consuming country and *have not* been adjusted for quality differences, as reflected in their gravity and sulfur content.

The selected historical crude oil prices for these benchmarks exhibit a high degree of variability (to be expected with a six-fold variance in 11.5 years, before, during and after a global recession. The correlation among all crude price movements however is high, 0.96+, in all cases except Maya (0.92) which in terms of quality is equivalent to Mars, reinforcing the notion that even accounting for levels of quality and different points of delivery, the long-term fungibility of crude oil allows substitution among grades to the extent that countries have refining capacity to process lower grades of crude.[48]

For instance, forward projections of global prices are not likely to exhibit a six-fold increase in prices over the next 11 years as they have in the past. Recent price history has been very volatile, with WCS prices falling from highs near $120/bbl in 2008 to lows near $20/bbl in January 2009; consequently, extrapolations are based on the average prices received post-recession, 2008-2011. Price differentials have also varied widely on a month-to-month basis. Daily price differentials exhibit even greater volatility and monthly averages were used to smooth (average out) these daily fluctuations.

The reference price bundle is represented by Maya, which in terms of quality, is equivalent to WCS. Maya, however, is priced based on a formula.[49] In order to utilize Maya pricing directly, we must first establish the price of West Texas Sour and three-percent-sulfur fuel oil prices, as well as the sweet crude prices. Since WTS and fuel oil prices have their own markets, the general price correlation is close but cannot be predicted to remain so.[50]

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[48] Coking facilities are a convenient proxy for heavy oil capacity.

[49] According to Bloomberg, the current formula is a value supplied by PEMEX represents the official selling price spread, also commonly known as a K factor for Maya crude oil export price formula to the United States. An outright price in US dollars per barrel is calculated using Bloomberg's assessed spot crude oil prices in the following formula: "((0.4 * (WTS + 3% Fuel Oil)) + (0.1 * (LLS + Dated Brent))) + adjustment factor," Source: http://www.bloomberg.com/quote/MOSPMAUS:IND

[50] Generally, fuel oil prices are high currently, relative to crude oil. This is likely because refiners have cut the amount of crude oil they are currently running and are operating within their most efficient capacity, which is within coking capacity, and therefore not running crude to make (normally) low-valued fuel oil. Currently, fuel oil is relatively expensive because of a shortage of supply. Also, China is growing strongly and importing fuel oil for electricity generation, which increases overall demand. The coker turns the bottom of the barrel into naphtha and gasoil, which are treated and become gasoline, jet fuel and diesel. The coker also produces petroleum coke from the molecules that can't be transformed into a liquid. A refinery without a coker turns the bottom of the barrel into fuel oil, which is used as bunker fuel on ships or is burned to create electricity in places that don't have natural gas or coal, like Hawaii.

This is used with the benchmark price of heavy oil blends in order to establish the expected price/differential values for the various heavy blends used for reference as shown in Table 20 below.

TABLE 20: MAJOR BENCHMARKS USED FOR COMPUTING PRICE DIFFERENTIALS

	WCS & Lloyd Blend	Cushing WTI	Maya	Saudi Medium	CA Kern	China Daqing	Brent	LLS	Mars
Correlation with WCS		0.969	0.874	0.977	0.978	0.966	0.969	0.975	0.964
Correlation with WTI			0.882	0.987	0.988	0.987	0.991	0.994	0.973
Correlation with Maya				0.903	0.892	0.896	0.900	0.899	0.859
Correlation with Brent								0.996	0.987
Correlation with LLS									0.989
Average 2000-11	43.27	53.64	41.10	50.57	48.09	54.43	54.89	55.73	64.76
Average 2008-11	71.95	80.40	66.39	80.27	76.27	83.38	85.02	84.69	80.04
Average Last 12 Months	79.02	87.80	79.24	94.41	90.63	97.68	99.56	96.56	92.13

FOB spot market prices of WCS were $2.17/bbl higher than Maya averaged over the last 11.5 years, $5.56/bbl higher on average since 2008, but only $0.22/bbl on average for the last 12 months. In the last year, WCS ranged from a *premium* over Maya by as much as $14/bbl and a $10/bbl *discount*.

The differential value between WCS and Maya though, has varied by as much as $24/bbl, although the two crudes are delivered to geographic points separated by a distance of less than 700 miles. Quality adjustments for comparing WCS to other crudes are most effectively established using a basket of LLS, Brent, and WTI to an average of WCS and Maya prices.

Given the volatility of the relationship between Maya and WCS, the netback price for Canadian exports is best approximated using LLS. Maya and WCS often move in the opposite direction in the same month, but the average difference between the two series is only about 0.5 percent over the last 12 years.

QUALITY CHARACTERISTICS

Since WCS heavy crude as shipped typically is harder to process, represented by a quality differential (i.e., lower specific gravity) with other blends, comparisons must reflect a density quality adjustment as well as sulfur in order to establish equivalency. Each benchmark price must be adjusted to account for the discount of lower quality across the world market.

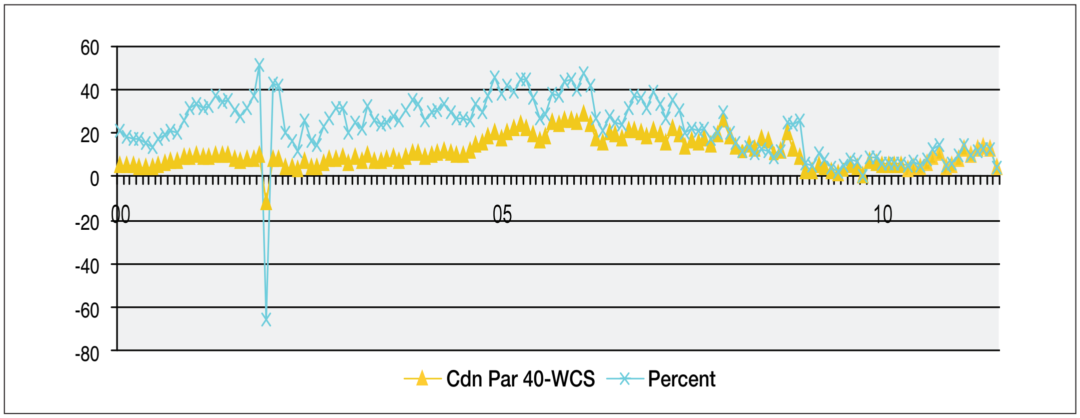
The total price differential or discount for heavy crude oils compared to intermediates averaged about 30 percent of intermediate oils' reference price when prices for intermediate benchmarks were in the range of $60 to $80/bbl. When intermediate benchmarks exceeded a price of $80/bbl, the heavy oil discount was closer to 20 percent.

The average actual adjustment for Maya and WCS heavy crudes, according to World Bank comparisons, was $3.01 US/bbl with a 23.7 percent quality adjustment from 2000 to the present.

CANADIAN SWEET COMPARED TO WCS

We can adjust for quality differences within Canadian crudes as well, in order to determine the magnitude of the quality adjustment. Here, both product streams are priced at Hardisty, where the comparison is net of transportation costs. In this case, the quality differentials appear to have fallen since 2008 in terms of percent difference. On average, the difference is approximately $11.34 Cdn/bbl with a quality differential of nearly 23 percent. The average over the past 12 months, however, illustrates that this relationship has some volatility and inconstancy associated with it, where the average difference over this period was $8.06 Cdn/bbl and a 9.8 percent difference in quality discounts.

FIGURE 24: QUALITY ATTRIBUTES EXPRESSED AS PRICE DIFFERENTIALS



QUALITY DISCOUNTS

We have to discount WCS relative to a common base in order to gain or establish an equivalency for refining capability. At the present time, Brent crude provides that standard, although we expect this to change to LLS post-2016. Table 21 below incorporates quality discounts by benchmark type, and contains average prices for the periods 2000 to 2011. Each crude oil price series has been adjusted for quality to enable comparisons with WCS. The basis of these comparisons is that each degree of API raises the price $0.007 US per dollar of Brent, while each additional one percentage point of sulfur lowers the price $0.056 US per dollar of Brent.[51]

[51] Robert Bacon and Silvana Tordo, "Crude Oil Price Differentials and Differences in Oil Qualities: A Statistical Analysis," *ESMAP Technical Paper, 081*, World Bank, October 2005, p.49

TABLE 21: CRUDE OIL PRICES EXAMINED TO COMPUTE TOTAL PRICE DIFFERENTIALS

Crude Type	API	Sulfur	API Quality Adj in %	Sulfur Quality Adj in %	Net Adj %
Heavy Crude Price Series Used for Comparisons					
Western Canadian Select, Hardisty	22.0	3.05%	–	–	–
Daqing	27.0	0.10%	-3.5%	-16.5%	-20.0%
Cano Limon	29.2	0.50%	-5.0%	-14.3%	-19.3%
Oriente	24.1	1.51%	-1.5%	-8.6%	-10.1%
Sidi Kerir Iran Heavy	31.5	1.80%	-6.7%	-7.0%	-13.7%
Maya	21.8	3.33%	0.1%	1.6%	1.7%
Arab Heavy	27.7	2.87%	-4.0%	-1.0%	-5.0%
Alaska 1st Purchase	30.0	1.10%	-5.6%	-10.9%	-16.5%
Kern	18.0	1.20%	2.8%	-10.4%	-7.6%
Bachaquero 17 1997 Only	17.0	2.30%	3.5%	-4.2%	-0.7%
Mars	30.3	1.91%	-5.8%	-6.4%	-12.2%
Intermediates Used for Benchmarks					
Fateh	31.0	2.00%	-6.3%	-5.9%	-12.2%
Global Average Export Weighted	avg	avg			
Brent	38.0	0.37%	-11.2%	-15.0%	-26.2%
US Average Import Weighted	avg	avg			
WTI	40.0	0.42%	-12.6%	-12.4%	-25.0%
WTS	32.8	1.98%	-7.6%	-6.0%	-13.6%
LLS	37.7	0.34%	-12.6%	-15.2%	-27.8%
Saudi Medium	30.2	2.59%	-5.7%	-2.6%	-8.3%
Canadia Par 40	40.0	0.50%	-12.6%	-14.3%	-26.9%

TRANSPORTATION COST ASSUMPTIONS FOR POTENTIAL CANADIAN EXPORTS

Transportation costs are a key factor in differentiating the costs of comparable products. Transportation costs in this report have been derived from exhibits contained in NEB applications for pipeline construction and expansions, subject-matter experts and published data sources, then extrapolated as a function of distance to tidewater ports of departure for comparison. Access to Gulf Coast ports serves as an example. Gaining access to these ports will involve new transmission capacity, but overall lowered costs. By accessing these ports, however, the product as shipped is more likely to be redirected to US-based refineries rather than exported to world markets.

The cost of product movement is critical to the delivered price at points of processing. Although prices in individual crude markets do not differ exactly by the transportation costs, this provides a key indicator of current and forecast market price levels. There are several reasons for this, including:

1. Transportation costs may vary over time, depending on competition along pipeline routes, alternative destinations, pumping costs or environmental or regulatory standards;
2. Stochastic shock in both supply and demand markets will change price levels between and within existing markets, creating temporary shortfalls and surplus conditions;

3. The availability of diluent will change the use of certain transportation systems and affect crude pricing and supplies. Diluent availability ultimately affects the netback to producers more than the crude price. The refiner is indifferent to refiner cost of production;
4. Differences in quality mix for a variable quality crude or compounded crudes, as well as factors such as credit risks, quantity discounts, inventory stocks and seasonal variations can cause price differences and, hence, imperfect correlation of prices even in highly efficient markets.[52]

DELIVERED COSTS

Transportation costs for other paths are calculated by assuming average transportation costs are proportional to pipeline distance (see Table 22 below). Pipeline transportation for crude oil over long distances is generally much less expensive than alternative ground transportation by rail or truck. Although the infrastructure, pipes and pumping stations are fixed at any point in time, pipelines can move different types of product and reverse-flow if regional demands warrant. Rail and truck transportation can offer greater flexibility to move crude among refining centres, but each can add \$6-\$10/bbl, usually limiting trucking to a radius of about 100 miles before other alternatives become cheaper, making it the final leg for shipping. Estimates are shown in constant 2010 dollars and are expected to demonstrate slow real-cost growth through 2030.

Table 22 below uses publicly available estimates of point-to-point transportation costs and extrapolates them on the basis of distance. Costs for the transportation path from Hardisty to Cushing are based upon the Keystone pipeline estimates. EnSys[53] have estimated tanker charges to transport WCS from the BC coast to China; that estimate is used to project a delivery cost by tanker from Port Arthur also extrapolated based on distance. A new pipeline from Hardisty, if operated at full capacity, is assumed able to deliver a barrel of crude to Port Arthur for < \$6.50, adding about seven percent of the WCS average FOB spot market price in July 2011 at Hardisty.

[52] Hay, George, John C. Hilke and Philip B.Nelson (1988) "Geographic Market Definition in an International Context," *Chicago-Kent Law Review* 64:3:711-39.

[53] Op cit.

TABLE 22: ILLUSTRATIVE TRANSIT COSTS ASSUMPTIONS FOR WCS FROM HARDISTY TO USGC, BC, & LONG BEACH, $2010/BBL

Transportation Paths	2010	2020	2030	KM
Pipelines				
Hardisty to Cushing[54]	4.58	5.36	5.88	2,687
Cushing to USGC[55]	1.83	2.15	2.35	503
Hardisty to USGC[56]	6.41	7.51	8.23	3,190
Hardisty to Long Beach CA	5.42	6.35	6.96	2,698
Hardisty to BC coast	1.93	2.26	2.48	1,150
Tankers				
BC Coast to China	1.84	2.44	2.86	3,456
Port Arthur to UK	3.88	5.15	6.03	7,290

PRICE FORECAST

The price forecast utilized here is adapted from NEB filings and world price estimates from the EIA in 2010. In this case, the price forecast reflects two periods for illustration: the period from present to 2015, at which point we expect the bottleneck at Cushing to be alleviated, and the period from 2016 to 2030, when access to Gulf Coast ports and Asian markets is available. Transportation costs are assumed to be fixed based on a distance calculation, and during the initial period subject to additional rail and trucking costs for any movement beyond Cushing, OK.

During the initial period, the sales price, quality discount and trading index are known and assumed not to change. Thus, Canadian heavy crude trades during this period based on a discount from WTI, which in turn is discounted from LLS and Brent on the world market. However, comparing a differential for Canadian crude to world prices during the current period distorts a calculation of world price differentials, due to the fact that it is discounted beyond only quality characteristics due to congestion and competition with overloaded Midwest refineries at the present time. In other words, the price differential from current WTI discounts (at Cushing relative to world prices) is a reality that can't be physically overcome at the present time.

Table 24 following presents crude oil price forecasts to 2030 for LLS, Maya and WCS. This forecast was chosen for consistency of comparisons with forecasts and assumptions embedded in recent applications made to the NEB for the Keystone XL and Gateway projects. Prices and differentials for 2020 and beyond are the most relevant, since permitting and construction would likely require several years. These price forecasts from other studies are especially useful because quality differences, but not transportation costs, are already reflected in the spot market FOB price.

54 Hardisty figures based on costs and distances reported in: EnSys, "Keystone XL Assessment-Final Report," prepared for the USDOE Office of Policy and International Affairs, December 23, 2010.

55 Cushing costs calculated as a remainder, China estimates derived from Gateway NEB filing data.

56 Page 49, ibid.

This annualized price scenario presented is not a forecast per se, but an extrapolation of forecast values filed with the NEB for the assumed transition period beginning in 2016. The post 2016 period represents the de-bottlenecked pipeline capacity increase available to Canadian heavy oil producers. Prices in the scenario are based on an assumed real price increase of 1% and an *expected inflation rate* of 1%.

The price scenario can be explained generally as follows. Without additional export capacity, Canadian suppliers will slowly increase production, further depressing the price of WCS in an already congested market at Cushing. In the base case scenario, the real price of WCS is assumed to rise over time, as do all crude oil prices, but developing export markets will permit WCS to be priced more favorably relative to its quality characteristics (due to access to a wider range of refiners), and the value that can be derived from processing it in refineries with appropriate coking capacity.

If export capacity is built to the West Coast, prices of LLS and Maya, San Joaquin Valley Heavy and Arab Medium are set in geographically separate markets. We assume, however, the same ratio will apply. Thus, prices can be assumed to remain unchanged. However, in this case a reduction in supply to Cushing caused by an increase in exports to California or Asia is likely to cause prices of WTI and WCS to rise.

Table 23 contains key benchmark crude price assumptions used to examine export potentials south to Cushing and Port Arthur,[57] and presents the scenario that describes the nature of the price differential over time. In this table, WTI is discontinued as a reference point past 2015, since we assume that at that point, WTI is no longer the relevant comparative benchmark, the transportation bottleneck is removed eliminating Brent as a standard and pricing will be based relative to LLS from that point forward.

The results of these calculations are limited by several assumptions. Key among them is the constraint of pipeline capacity and additions both into the Gulf Coast region and to the Pacific Coast. In order to estimate the magnitude of the price differential, we have assumed that all WCS heavy crude currently bottlenecked at Cushing (1.3 MBD) and additional capacity from either Keystone XL or smaller incremental additions will increase capacity to the Gulf Coast by 700 KBD. The sum of these additions (2 MBD) is used in conjunction with the price differential as the basis for estimating the total economic potential from new sales that would be available to Canadian producers.

Similarly, this report assumes that new capacity is built to the West Coast to carry heavy oil to California[58] and Asian markets. In this case, pipelines are assumed to be in operation and available by 2015 for Gulf Coast refineries and 2020 for Pacific tidewater shipment.

For simplicity, we assume that once access to Gulf Coast refineries is available, all barrels shipped by this route have access to this market. We do not have a model that differentiates by location, so the issues of displacement or routes back to the Midwest are not assumed to invalidate the price and revenue potential from the new, adjusted differential.

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[57] Canadian crude exported to Port Arthur could potentially be further transported to the UK so Brent is included for comparison.

[58] An important assumption is made regarding the California fraction of assumed volume where declines in production from Kern and other heavy oils results in stranded capacity is replaced by Canadian crude. Low Carbon Fuel Standard limits are discounted for purposes of this analysis.

Finally, to construct this scenario, we do not comment on the efficacy of new pipeline capacity that may be needed to sustain further oil sands operations for heavy oil in the future. Rather, we assume that as capacity is added, sufficient supply of heavy crude will be available from the oil sands region, and will be limited only by available transfer capacity during this study period. Further expansion in future years will be dependent on additional pipeline development or tidewater access.

If export capacity is built to the Gulf Coast with consequent increases in deliveries to existing US refining centres, the price of LLS is not likely to change dramatically, because it is tied to the price of Brent in the short run. Ultimately, we expect the price of Brent to fall relative to LLS, while imports of Maya (or other similar heavy sour crudes) would be pushed offshore and delivered to other markets because it has a higher forecast price and is of somewhat lower quality than WCS.

TABLE 23: HEAVY CRUDE PRICE FORECAST 2011 TO 2030

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
LLS																				
Spot Price at St. James	105.00	100.00	102.00	104.04	106.12	100.00	102.00	104.04	106.12	108.24	110.41	112.62	114.87	117.17	119.51	121.90	124.34	126.82	129.36	131.95
Relative Transportation to GC Refining Centre	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Refiner Cost of LLS	**105.00**	**100.00**	**102.00**	**104.04**	**106.12**	**100.00**	**102.00**	**104.04**	**106.12**	**108.24**	**110.41**	**112.62**	**114.87**	**117.17**	**119.51**	**121.90**	**124.34**	**126.82**	**129.36**	**131.95**
WTI																				
Spot Price at Cushing	95.00	95.00	95.00	95.00	95.00															
Relative Transportation to GC Refining Centre	12.00	12.00	12.00	12.00	12.00															
Total Refiner Cost WTI Blend	**107.00**	**107.00**	**107.00**	**107.00**	**107.00**															
Maya																				
Spot Price at Load Port	92.54	92.54	91.80	93.64	95.51	92.00	93.84	95.72	97.63	99.58	101.58	103.61	105.68	107.79	109.95	112.15	114.39	116.68	119.01	121.39
Relative Transportation to GC Refining Centre	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Total Refiner Cost of Maya	**93.54**	**93.54**	**92.80**	**94.64**	**96.51**	**93.00**	**94.84**	**96.72**	**98.63**	**100.58**	**102.58**	**104.61**	**106.68**	**108.79**	**110.95**	**113.15**	**115.39**	**117.68**	**120.01**	**122.39**
WCS																				
Spot Price at Hardisty	68.44	82.00	82.00	82.00	82.00	75.00	76.50	78.03	79.59	81.18	82.81	84.46	86.15	87.87	89.63	91.42	93.25	95.12	97.02	98.96
Relative Transportation to GC Refining Centre	14.58	15.00	15.00	15.00	15.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00
Total Refiner Cost of WCS	**83.02**	**97.00**	**97.00**	**97.00**	**97.00**	**82.00**	**83.50**	**85.03**	**86.59**	**88.18**	**89.81**	**91.46**	**93.15**	**94.87**	**96.63**	**98.42**	**100.25**	**102.12**	**104.02**	**105.96**
WTI/WCS Spread		10.00	10.00	10.00	10.00															
LLS/WCS Spread						18.00	18.50	19.01	19.53	20.06	20.60	21.15	21.72	22.29	22.88	23.47	24.08	24.71	25.34	25.99

All Values in $US / bbl
2011 to 2015 is prior to DeBottlenecking
2016 to 2030 is Post DeBottlenecking
2011 data measured in YTD

As stated above, beyond 2016, we assume capacity constraints at Cushing to be removed, and the additional constraint discount applied to WCS is removed. This means that WCS can be effectively sold at a world price with quality adjustments comparable to Maya and using LLS as the reference price. The additional potential value to Canadian producers is calculated after this discount and an adjustment for costs of transportation. This value is expressed in Table 24 as a differential available for shipping after the bottleneck is removed at Cushing, and/or after new tidewater access is available to the Pacific Coast.

The discount for quality in the assumed scenario uses Maya for the Gulf Coast proxy, San Joaquin Valley Heavy for the California proxy and Arab Medium for the Asian market proxy. The discount applied relies on the initial assumptions filed by Muse-Stancil in the Gateway application of an LLS price of $100 US, in 2016. The discount of Maya to LLS[59] is $8.00 in 2016, $12.00 for San Joaquin Valley Heavy and $10.00 for Arab Medium.

The result in the tables should be treated as a rational scenario rather than a forecast. We assume there is sufficient growth in the market to absorb new supply, and we assume a steady increase in oil sands output from Alberta sufficient to meet that demand. In other words, in the elements of this scenario, we include no constraints either in terms of available product or shipping capacity. In the real world, we would expect the *net* gain to be smaller based on competition in world supply, a softening of world prices as new product was added and differential shifts in shipments to different world markets.

For instance, the scenario relies on an assumption that Cushing constraints are alleviated at an arbitrary date (2015).[60] This could be accomplished by any combination of added capacity up to and including Keystone XL. This same context is assumed for access to Asian markets via tidewater access in British Columbia. Consequently, the scenario should be taken as an estimate of the magnitude of the price differential that is available at the margin for new Canadian market potential, as opposed to an expectation of realistic netbacks, which will be a dynamic reflection of supply and demand relationships month- to-month and year-to-year in each market.

Based on forecast price levels in 2011 escalated forward, WCS, transported to these destinations and adjusted for quality differences, would likely have higher differential price capture available to producers based on the period ending in 2015 and the period beginning in 2016. This range could be as high as $9.49/bbl at the USGC in 2016. At an escalation rate of two percent per annum, this is the equivalent of $12.52/bbl by 2030.

In order to calculate the upper price bound available, we have assumed that exports via the Gateway pipeline would be shipped to Asia without corresponding diminishment of volumes to the Gulf Coast, an arbitrary assumption that relies on adequate supply growth from the oil sands region. Additionally, we have assumed that China would set its internal crude oil prices to rise with inflation, but not faster. In real terms, Arab Medium can be used as a proxy for quality, allowing for an adjustment of approximately $10 US in 2016 to LLS. The result is a differential of $10.30 /bbl in 2016 for WCS exports to China relative to the constrained shipping access price in 2015 (the equivalent price if shipping access were available).

Using the same assumptions, export potentials for WCS shipped to California are based on the assumption that quality adjustments reflect the basis of San Joaquin Valley Heavy, where differences are minimal and future pipeline transportation costs would total $6.35/bbl in 2016. The discount for quality in this case is approximately $12.00 US to LLS, which creates an opportunity to capture an additional $6.65 US per bbl in 2016 compared to the assumed limits in access of 2015.

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[59] In a perfect market, WCS and Maya would have about the same value to a refiner. This is based on their similar API gravity and sulfur as a proxy for yield of refined products and operating costs. Argus calls this the refinery gate value of a crude. Our current guess is the difference between the refining value of heavy sour versus light sweet is $5/bbl.

[60] For example, the Wrangler Pipeline (the new line from Cushing to the USGC) capacity is set at 800 KBD and effectively is the extension to the Gulf Coast from Cushing that doesn't exist today. The question becomes how much unused capacity is there on the existing pipeline systems that move crude into Cushing — enough to move 800,000 to the USSGC? This would determine how much additional crude can move once Wrangler is built — some of which could be Bakken. Keystone XL could go all the way from Canada to the USGC — and would increase total Keystone capacity by 700 KBD and could move as much as 900 KBD all the way to the Gulf Coast. Reversal of Seaway provides another 430 KBD of takeaway capacity from Cushing. Wrangler at 800 KBD increases the total to 1230 KBD.

PRICING ARRANGEMENT FOR WCS (CURRENT CASE)

At present, virtually all WCS supplies are shipped to the US via the Canadian/US pipeline system and as such, are subject to market forces at various points. WCS shipped to the US can transit directly to Cushing storage, directly to storage in Patoka and Chicago, IL that feeds the Midwest refineries, directly to points between Hardisty and the Midwest or indirectly to Cushing via storage in the Midwest. The price at Hardisty represents the producer market price after production and shipping to the transfer point at Hardisty, but not the final price of the product as received by a refiner.

The final price includes shipping to move between Hardisty and the refinery. Since Midwest refiners are processing as much WCS as possible and because pipelines from the Midwest that could move WCS to refineries in the USGC are at capacity, this final price currently reflects movement by rail, barge and truck to the USGC.[61] [62]

Each additional transportation step involves additional handling costs, making the total cost of moving product higher than if pipeline capacity were available directly from Hardisty to Gulf Coast producers, where current and future excess capacity exists.

The result is a depressed price at Hardisty, relative to what a producer in North Dakota, or an importer of Maya on the Gulf Coast faces. There are two ways to solve this problem and in so doing, raise the price at Hardisty that a producer can capture.

First, the transportation costs can be lowered, principally by avoiding the steep last barrel movement costs of rail and truck. This would be accomplished by a higher capacity and more efficient pipeline system, such as Keystone XL, adjusting current pipes to accommodate Canadian (and perhaps North Dakota) supplies, or the construction of upgrades to the existing system.

Second, since the Midwest refinery market cannot absorb significant additional quantities of heavy sour crude, shipping the product to markets where there is unused capacity for heavy sour crudes (Gulf Coast, California's San Joaquin Valley or Chinese and Asian coastal sites) will allow a price to be set for the delivered product that is discounted more efficiently to a different benchmark commodity. This change will result in a higher price at the shipping point; i.e., a higher netback price to producers at Hardisty.

In the current case, WCS is priced relative to WTI, an historic benchmark that reflects a broad base of refining capacity in the Midwest. As explained earlier, this market is constrained in its ability to accept higher volumes. Moving additional supplies to Gulf Coast refiners is difficult and must rely on inefficient transportation systems such as rail and trucking instead of pipelines. A Canadian producer must accept the higher-than-optimal cost of transportation that is reflected in the disparity of price between WTI and other benchmark crude oils like Brent, in order to move the crude to a market where there is unused capacity. It is the higher-than-optimal cost of transportation to move crude from Cushing to a world market that determines the discount for WCS vs. any world benchmark price.

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[61] US Midwest refiners have an incentive to maximize the amount of heavy sour crude they can process and consequently process as much WCS as possible. Beyond heavy sour crude they will preferentially process sweeter and lighter crude, such as that supplied by North Dakota. In 2010, crude input to PADD 2 refineries totaled about 3.3 MBD, of which 1.3 was imported, 1.2 was moved from other PADDs (principally PADD 3, the USGC) and the balance was supplied from within PADD 2, including from stocks at Cushing and from North Dakota

[62] WCS isn't significantly discounted more than Bakken. WCS trades at a lower price than Bakken largely due to the distance from the refinery market and is therefore more expensive to get to market due to WCS quality differences. Bakken crude has an API gravity between 38 and 40 and sulfur of 0.2 percent. Currently, Bakken is now trading below WTI — by $1.88 — even though it is a higher quality crude than WTI, because of transportation bottlenecks between North Dakota and the USGC/US Midwest crude markets.

We can describe this as:

Cdn Price — priced in US dollars — (C_p) at Hardisty is assumed to be the producers' MC.

The price of this product at the refinery gate then reflects the cost of transportation T_c, as well as a quality discount from the benchmark of WTI or WTI_{qa} of approximately 10 percent.

So the price paid at the refinery is:

$WTI - WTI_{qa} - T_c = $ WCS at Hardisty

Today, illustratively this exists as

$C_p = WTI - WTI_{qa} - T_c$

where C_p is the current average price of WCS at Hardisty

WTI = $95.00

WTI_{qa} = $95*10% = $9.00

Tc = $4.58 + $10.00 = $14.58

Cp = $95 - $9 - $14.58

Cp should equal approximately $70.00

This suggests that if the current price were $70, then supply just clears, and there is incentive to improve the situation by either clearing the bottleneck or building new pipelines.

Remove the Bottleneck

After the bottleneck is removed, WCS can move to the USGC region by pipeline, eliminating the last and expensive transportation legs; consequently, we should improve the calculus, and have the potential to capture a higher fraction of the world price or differential Dp.

Now the differential (Dp) formula at the Gulf Coast changes to:

Dp = LLS - quality adjustment for Maya - Tc - Cp

= LLS - (LLS-Maya) – Tc - Cp

where Cp is the WCS price at Hardisty

LLS is the world price at St. James

Maya is Gulf Coast price for crude of similar quality to WCS

Tc is the transportation cost to Tidewater port/refinery

Assuming

WCS at Hardisty price of $75, LLS of $100, and Maya of $92

Quality Adjustment is LLS – Maya = $100 - $92 = $8

Transport Cost of $7.50

$100 - $8 - $7.50 = $84.50 is price paid by refiner to get product

$84.50 - $75 = 9.50 additional differential to Cdn producer beyond what is paid today

So Dp = $100 – $8 – $7.50 – $75 = $9.5

The same calculus should apply to shipments to the West Coast for Pacific markets, with a different and appropriate quality discount reflecting the refinery capability and capacity at the receiving terminals.

TABLE 24: PRICE AND DIFFERENTIALS FORECAST FOR CANADIAN CRUDE EXPORTS

	EXPORT POTENTIALS FOR WCS TO CUSHING AND USGC BY YEAR														
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Change in Price at Hardisty Shipping to GC															
LLS Price at St. James	**100.00**	102.00	104.04	106.12	108.24	110.41	112.62	114.87	117.17	119.51	121.90	124.34	126.82	129.36	131.95
LLS Gulf Coast Price for Maya	**92.00**	93.84	95.72	97.63	99.58	101.58	103.61	105.68	107.79	109.95	112.15	114.39	116.68	119.01	121.39
Discount for Quality at Gulf Coast	**8.00**	8.16	8.32	8.49	8.66	8.83	9.01	9.19	9.37	9.56	9.75	9.95	10.15	10.35	10.56
WCS price at Hardisty	**75.00**	76.50	78.03	79.59	81.18	82.81	84.46	86.15	87.87	89.63	91.42	93.25	95.12	97.02	98.96
Relative Transportation to GC Refining Centre	**7.51**	7.66	7.81	7.97	8.13	8.29	8.46	8.63	8.80	8.98	9.15	9.34	9.52	9.71	9.91
Additional Value to Canadian Producers	**9.49**	9.68	9.87	10.07	10.27	10.48	10.69	10.90	11.12	11.34	11.57	11.80	12.04	12.28	12.52
Change in Price for California Markets															
LLS Reference Price	100.00	102.00	104.04	106.12	**108.24**	110.41	112.62	114.87	117.17	119.51	121.90	124.34	126.82	129.36	131.95
LLS West Coast Price for SJV Heavy	88.00	89.76	91.56	93.39	**95.25**	97.16	99.10	101.08	103.11	105.17	107.27	109.42	111.61	113.84	116.11
Discount for Quality at West Coast	12.00	12.24	12.48	12.73	**12.99**	13.25	13.51	13.78	14.06	14.34	14.63	14.92	15.22	15.52	15.83
WCS price at Hardisty	75.00	76.50	78.03	79.59	**81.18**	82.81	84.46	86.15	87.87	89.63	91.42	93.25	95.12	97.02	98.96
Relative Transportation Cost Hardisty to California	6.35	6.48	6.61	6.74	**6.87**	7.01	7.15	7.29	7.44	7.59	7.74	7.90	8.05	8.21	8.38
Additional Value to Canadian Producers	6.65	6.78	6.92	7.06	**7.20**	7.34	7.49	7.64	7.79	7.95	8.11	8.27	8.43	8.60	8.77
Change in Price for Asian Markets															
LLS Reference Price	100.00	102.00	104.04	106.12	**108.24**	110.41	112.62	114.87	117.17	119.51	121.90	124.34	126.82	129.36	131.95
LLS West Coast Price for Arab Medium	90.00	91.80	93.64	95.51	**97.42**	99.37	101.35	103.38	105.45	107.56	109.71	111.90	114.14	116.42	118.75
Discount for Quality at West Coast	10.00	10.20	10.40	10.61	**10.82**	11.04	11.26	11.49	11.72	11.95	12.19	12.43	12.68	12.94	13.19
WCS price at Hardisty	75.00	76.50	78.03	79.59	**81.18**	82.81	84.46	86.15	87.87	89.63	91.42	93.25	95.12	97.02	98.96
Relative Transportation Cost Hardisty to Asia	4.70	4.79	4.89	4.99	**5.09**	5.19	5.29	5.40	5.51	5.62	5.73	5.84	5.96	6.08	6.20
Additional Value to Canadian Producers	10.30	10.51	10.72	10.93	**11.15**	11.37	11.60	11.83	12.07	12.31	12.56	12.81	13.06	13.32	13.59
Supply Volume															
Capacity in pipeline in MBD base	1.3	2.0	2.0	2.0	2.0	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Additions	0.7				0.5										
Total		2.0	2.0	2.0	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Current Flow	1.3	1.4	1.5	1.6	1.7	1.9	2.1	2.3	2.4	2.5	2.5	2.5	2.5	2.5	2.5
Additional Flow to Gulf Coast		0.1	0.1	0.1	0.1	0.1	0.1	0.1							
Additional Flow to West Coast / California					0.05	0.05	0.05	0.05	0.05						
Additional Flow to West Coast / Asia					0.05	0.05	0.05	0.05	0.05						
Total Flow	1.4	1.5	1.6	1.7	1.9	2.1	2.3	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5

IX. IMPACTS OF ADDITIONAL REVENUE ON THE CANADIAN ECONOMY

We have used a multiregional input-output model (I/O) to estimate the magnitude of the benefit of additional revenues to Canada at the upper end of the range of differential that is available if producers have access to world market pricing.

The model is derived from publicly available I/O tables, which are widely used as a base for both Canadian and US research calculations. The model is the US-Canada Multi-Regional I/O Model (UCMRIO 2.0) based on StatsCanada and US Bureau of Economic Analysis (USBEA) I/O tables updated from base year 2006.

This model generates broad multipliers for income, employment and taxes based on shocking the model with injections of revenue from new purchases of Canadian products. The multipliers are conservative and consistent with Statistics Canada estimates of provincial and national impacts including induced or secondary impacts.

The analysis is based or grounded in estimates of increased volumes of Canadian unconventional or heavy oil production during the study period following de-bottlenecking at the Cushing hub post-2016 through 2030. The model is sensitive to changes in the macro-economy that may reflect future demand and world supply characteristics. The forces which will influence this price differential the most, but which are least known or predictable today include the extent to which new US domestic supplies crowd out Canadian imports, actual PADD refinery utilization and in the case of Pacific markets, the extent to which stranded capacity in California markets is available for WCS, and future Asian investments in coking capacity suitable for heavy crudes.

The parameters of this analysis are:

a. During the period 2011 to 2015, constraints remain in transportation of crude products from Canada destined for Midwest and Gulf Coast refineries.

b. From 2016, transportation capacity increases from Canada to US Gulf Coast refineries and to Pacific markets. We have arbitrarily assumed that this occurs in 2015 for Gulf Coast access and begins in 2020 for Pacific tidewater access. In the case of the Gulf Coast, we have assumed that oil processed in these refineries is distributed within North American markets and displaces equal volumes of imported oil, primarily Maya and Venezuelan crudes. We assume that once transport capacity is available, Canadian producers supply an equal amount of product beginning with the availability of excess capacity. We assume that production increases are limited to available transfer capacity (effectively stranding new production or redirecting it to Canadian markets). Oil price differentials are measured during the study period as the difference between the benchmark LLS and Maya, adjusted for transportation costs. Volume increases are assumed from a base of 1.3 MBD currently with expansion to 2 MBD with new pipeline capacity.

c. In the case of Pacific tidewater access, we assume the export markets are either in California, where there is a growing surplus of heavy oil refining capacity, and in Asian markets where capacity exists in Korea and China for the forecast volume of heavy crude. We have arbitrarily assumed a split of 50 percent to each of these markets. Oil prices are based on a differential of LLS to San Joaquin Heavy in the case of California and Arab Medium for Asian markets. These transfers are assumed to begin in 2020. Pipeline capacity is assumed to expand from 0.3 MBD to 0.8 MBD with new capacity.

The input-output model is sensitive to changes in returning revenue flows for export sales and calculates a gross estimate of spending impacts on major categories. In this case, we were interested in cumulative levels reflecting the maximum possible return represented by the differential of current WCS to the available (discounted) world oil price after transportation adjustments.

I/O multipliers have some limitations, starting with the fact that they are not dynamic and produce a snapshot of the economy at a given point in time. In addition, these models do not explicitly consider alternatives and tend to emphasize the benefits of expenditures as opposed to costs, which are not explicitly identified in the model. Generally, these models treat all inputs as complements and exclude substitutes, which implies that increases in the demand for one input will reflect increases for other inputs as well. The economy as so modeled is assumed to have limitless amounts of all the inputs it requires and produces.

The I/O model in use in this study incorporates multiple, interactive and interdependent multipliers of spending and employment in creating the yearly snapshot of the economy. In the case of the supply region, namely the oil sands, the output multiplier is assumed to be 1.77 in Canada and the value-added multiplier for GDP is 1.00.

Table 25 represents the values from this maximum return of revenue from the value of the differential if fully captured during the study period. The benefits are unequally distributed, but even in provinces not directly benefitting from oil sales and transfers, the results represent significant future stimulus in the form of direct revenues, reinvestment and employment. In terms of overall GDP, the model estimates the magnitude of the total differential over 15 years. Taking the average value of the differential over this period, the annualized impact of this volume of additional revenue potential represents an annual increase of total Canadian GDP of nearly one percent.

TABLE 25: SUMMARY OF ECONOMIC IMPACTS

GDP in Billions of 2010 Cdn $	Employment (in ‘000 person years)	Total Federal, Provincial and Municipal Tax Receipts in Billions of 2010 Cdn $
131,837	649	27,235

Tables 26, 27 and 28 following break this down by region, emphasizing the difference between future flows to the Gulf Coast, which begin as early as 2016, and flows to Pacific tidewater destinations, which do not begin until 2020 at the earliest. The breakdown by province suggests the wide reach of the impacts as well as the diversity of the ultimate impacts including reinvestment of revenues.

TABLE 26: MIDWEST AND GULF COAST "ADDITIONAL" ECONOMIC IMPACTS 2016-2030

	$CAD Million		Thousand Person Years
	GDP	Compensation of Employees	Employment
Alberta	108,770	27,745	483
British Columbia	1,432	774	21
Manitoba	209	113	3
New Brunswick	41	20	1
Newfoundland & Labrador	18	6	0
Northwest Territories	7	4	0
Nova Scotia	42	21	1
Nunavut	1	1	0
Ontario	3,116	1,795	42
Prince Edward Island	3	2	0
Quebec	677	378	10
Saskatchewan	222	95	3
Yukon Territory	2	1	0
Total Canada	**114,540**	**30,956**	**564**

ADDITIONAL TAX RECEIPTS AS A RESULT OF ALBERTA OIL SANDS OPERATION 2016-2030, FEDERAL AND PROVINCIAL-MUNICIPAL IN 2010 MILLION CDN $

CAD Million	Indirect Tax	Personal Income Tax	Corporate Tax	Sum
Alberta	6,345	10,384	5,126	21,855
British Columbia	187	156	35	379
Manitoba	32	23	4	58
New Brunswick	6	4	1	11
Newfoundland & Labrador	2	1	1	4
Northwest Territories	1	0	0	1
Nova Scotia	7	5	1	13
Nunavut	0	0	0	0
Ontario	494	372	154	1,021
Prince Edward Island	1	0	0	1
Quebec	125	98	28	251
Saskatchewan	36	21	13	69
Yukon Territory	0	0	0	0

TABLE 27: CALIFORNIA "ADDITIONAL" ECONOMIC IMPACTS 2020-2030

	$CAD Million		Thousand Person Years
	GDP	Compensation of Employees	Employment
Alberta	6,445	1,644	29
British Columbia	85	46	1
Manitoba	12	7	0
New Brunswick	2	1	0
Newfoundland & Labrador	1	0	0
Northwest Territories	0	0	0
Nova Scotia	2	1	0
Nunavut	0	0	0
Ontario	185	106	3
Prince Edward Island	0	0	0
Quebec	40	22	1
Saskatchewan	13	6	0
Yukon Territory	0	0	0
Total Canada	**6,786**	**1,834**	**33**

ADDITIONAL TAX RECEIPTS AS A RESULT OF ALBERTA OIL SANDS OPERATION 2016-2030, FEDERAL AND PROVINCIAL-MUNICIPAL IN 2010 MILLION CDN $

CAD Million	Indirect Tax	Personal Income Tax	Corporate Tax	Sum
Alberta	376	615	304	1,295
British Columbia	11	9	2	22
Manitoba	2	1	0	3
New Brunswick	0	0	0	1
Newfoundland & Labrador	0	0	0	0
Northwest Territories	0	0	0	0
Nova Scotia	0	0	0	1
Nunavut	0	0	0	0
Ontario	29	22	9	60
Prince Edward Island	0	0	0	0
Quebec	7	6	2	15
Saskatchewan	2	1	1	4
Yukon Territory	0	0	0	0

TABLE 28: ASIA
"ADDITIONAL" ECONOMIC IMPACTS 2016-2030

	$CAD Million		Thousand Person Years
	GDP	Compensation of Employees	Employment
Alberta	9,982	2,546	44
British Columbia	131	71	2
Manitoba	19	10	0
New Brunswick	4	2	0
Newfoundland & Labrador	2	1	0
Northwest Territories	1	0	0
Nova Scotia	4	2	0
Nunavut	0	0	0
Ontario	286	165	4
Prince Edward Island	0	0	0
Quebec	62	35	1
Saskatchewan	20	9	0
Yukon Territory	0	0	0
Total Canada	**10,511**	**2,841**	**52**

ADDITIONAL TAX RECEIPTS AS A RESULT OF ALBERTA OIL SANDS OPERATION 2016-2030, FEDERAL AND PROVINCIAL-MUNICIPAL IN 2010 MILLION CDN $

CAD Million	Indirect Tax	Personal Income Tax	Corporate Tax	Sum
Alberta	582	953	470	2,006
British Columbia	17	14	3	35
Manitoba	3	2	0	5
New Brunswick	1	0	0	1
Newfoundland & Labrador	0	0	0	0
Northwest Territories	0	0	0	0
Nova Scotia	1	0	0	1
Nunavut	0	0	0	0
Ontario	45	34	14	94
Prince Edward Island	0	0	0	0
Quebec	11	9	3	23
Saskatchewan	3	2	1	6
Yukon Territory	0	0	0	0

X. CONCLUSIONS

Calculating the price differential for Canadian oil exports requires a significant set of caveats. These include the fact that there are limits in terms of production and transfer capacity, as well as shifting world market demands that are only beginning to manifest themselves. Canadian oil has characteristics in terms of quality that are represented as a discount in world or North American markets, which make its price relative to other blends with similar characteristics at the same moment in time.

Consequently, this study has focused on the nature of the product that can be produced, the current limits of sale, what relief might be expected in the near term, and finally on the absolute differential that would be available to Canadian products exported to tidewater shipping points after either pipeline capacity is increased or constraints are removed.

There are four scenarios for future Canadian exports through the study period of 2020 that describe the range of alternative outcomes. They are:

1. The constraints at Cushing remain intractable and product is effectively stranded, limiting exports to the US at current levels with the current price differential. No new tidewater access is available and production is limited to approximately 1.1 MBD of Alberta crude.
2. The Cushing pipeline constraint is eased through workarounds, or new capacity from Keystone XL. Canadian crude can be transported to processing facilities via the Gulf Coast (Port Arthur). No Canadian crude is assumed to be exported beyond US ports and it effectively displaces current US foreign imports such as Venezuelan or Mexican crude. In this case, the Brent world price is assumed to drop to current LLS levels over the study period (to 2020), and WTI closes towards LLS. Effectively, WCS trades at a discount to LLS rather than Brent or WTI. Available coking capacity in PADD 3 and PADD 5 is fully used with an increase of 1.5 MBD of WCS heavy crude.
3. The constraints at Cushing remain, but the Gateway pipeline is completed, and 700 KBD of WCS is exported to the West Coast or Asian markets. Prices equilibrate upward to LLS levels, and trade after adjustments for distance and quality based on LLS — WCS.
4. All constraints are lifted and Canadian heavy crude reaches both Gulf Coast processing and West Coast and Asian markets. Based on quality and distance adjustments, the product sells with a reference price based on LLS.

Of these possible outcomes, we have concluded that the most likely scenario, based on continuing demand in the US and growth in the Asian markets, even if slowed over the near term, suggests that between now and 2020, scenario 2 above is likely to prevail. The primary driver for this is likely to be a series of political and regulatory approvals that will allow steady capacity increases, sufficient to ease constraints and allow additional heavy oil product to be moved to US refineries.

In our conclusions following, we rely on a broad set of assumptions about current circumstances and market dynamics. In the most obvious recapitulation, the market for Canadian heavy oil is limited by several factors, of which the most obvious are the physical shipping capacity available, the fact that the nature of the product demands special refining capability and that it must accept a pricing discount. The most significant factor, however, is the distance involved in shipping the product with corresponding costs that are increased when inefficient last leg(s) transportation must be used.

We have identified and quantified the opportunity for Canadian oil if it is traded relative to world prices and benchmarks. Being able to sell based on a world price increases the range and bound of price differentials available and ultimately the netback to Canadian producers, providing a significant boost to the Canadian economy.

In order to come to these conclusions, we have made a range of assumptions, including the scenario cited above. We assume the constraints will be alleviated and that over the period identified in this study, the price of the current benchmark crude — Brent — will fall and converge with LLS, an emerging standard with characteristics closer to WCS. Using close proxies for quality to WCS, we expect higher potential fractions to be available for Canadian producers and shippers. Finally, we assume that in terms of timing and access, the US Gulf Coast will be open and accessible for increased volumes of Canadian products approximately five years before the Pacific Coast.

There is a strong incentive for producers to capture as much of this price differential as possible, which represents a substantial impact on overall Canadian and provincial revenues and employment. The most likely outcome is that the effective capture within this range is approximately one-third of the full value, although continued increases in upstream production efficiency have the potential to increase this figure substantially.

The risks to this scenario are varied with moderate uncertainty, but can be assigned generally to two areas, *world price levels and competition for available capacity* within the Midwest and Gulf Coast pipeline and refining sectors. Alternative supplies are being developed in the Midwest Bakken fields and will be direct competitors for heavy Canadian crude in the future. In the Pacific region, the attraction of the Asian market will draw competition from the Middle East, which combined with falling demand in portions of North America may drive prices towards the cost of production for Canadian products.

The elimination of the bottleneck at Cushing will create more price transparency for Canadian heavy crudes, with a corresponding increase in market confidence over the delivery of the product. In the short term, prices may fall somewhat, as the world price declines and LLS supersedes Brent as the appropriate benchmark. Available Midwest refining capacity should be adequate to service Canadian production increases over the time period of this report. Given the range identified here, neither of these is likely to significantly alter these conclusions.

EXPLAINING PRICE DIFFERENTIALS AND OPPORTUNITY FOR CANADIAN CRUDE OIL PRODUCTS

It is clear that at present there is a surplus of crude oil supply in the North American mid-continent. This situation has reduced the price of mid-continent crude oils to well below world levels and impacts WTI, Bakken and WCS. At the same time, supply problems have driven up the price of another major crude oil benchmark, Brent. Brent's supply dynamics have resulted in a large spread in price between crude oils trapped in the mid-continent and crude oils on the coast that compete with higher-priced Brent.

This exacerbates the situation where Canadian heavy oil products, predominantly those from the oil sands region, are discounted from the world market price in part due to the single-client relationship established with the US, in addition to quality discounts for gravity and sulfur content. Currently almost all oil sands crude production is exported to the US Midwest and is priced based on the benchmark crude in that region — WTI. WTI is currently discounted by more than $20US/bbl as compared to crude oil of similar quality of crude available elsewhere in the world, including Louisiana Light Sweet available in the US Gulf and Brent or North Sea Blend available in the North Sea. As a result, the price realized for Canadian crude exported into the US Midwest is substantially below the price of other world crudes.

The price of WTI is much lower than the price of other world crudes for several reasons.

1. There has been a dramatic increase in the supply of crude oil to the North American mid-continent.

   In 1988, Canada supplied about 525 KBD of crude to the US Midwest; in 2010, Canada supplied more than 1.2 MBD. In 2011, even more Canadian crude could be delivered to the US as additional pipeline capacity has come on line. In addition, US production of crude from the Bakken Shale formation has increased US domestic supply to the Midwest by 200 KBD.

2. This additional supply of crude to the Midwest has overwhelmed both the ability of Midwest refiners to process heavy sour crude and the existing crude oil infrastructure in the region.

   There was and continues to be insufficient pipeline capacity to move the crude delivered into the Midwest to other US refining centres where there is substantial demand for heavy crude. We note that total US imports of heavy crude were almost 4 MBD in 2010. Current pipeline capacity to move crude from the Midwest to the Gulf Coast is about 130 KBD; pipeline capacity to move crude into the Midwest from Canada exceeds 1 MBD. When crude supplies from Bakken and Canada increased, crude inventories in the Midwest increased and crude became trapped. As a result, the price of WTI plummeted relative to other world crude prices.

3. Regional market pressures have pushed up the prices of other world crude oils, specifically Brent and similar grades, magnifying the spread between WTI and Brent/other grades.

   Major disruptions to the supply of North Sea and African crudes in early 2011 pushed Brent and LLS prices higher, while WTI prices were moving lower. In addition, because Brent is the benchmark crude for Europe and is used to price a significant percentage of world crudes, the price of Brent is more sensitive to world events, like the Arab Spring and the loss of Libyan crude from world markets. Even recently, there have been disruptions to the availability of North Sea crude that have pushed the price of Brent higher.

The combined effect of these circumstances has been an absolute price of WCS that is quite low relative to world markets. Nonetheless, WCS sells at a fair market price for heavy sour crude that is being delivered into an infrastructure-constrained and oversupplied market.

As long as infrastructure constraints limit the movement of crude out of the US Midwest, WTI prices are likely to remain relatively low and under pressure. While it is true that immediate inventory concerns have been alleviated by moving crude out of Cushing, the crude is moving via typically prohibitively costly forms of transportation, like rail truck and barge. These movements make economic sense because of the wide spread between crude prices in the Midwest and the USGC.

Longer term, there are a number of infrastructure improvement projects in the early stages of development, including Keystone XL and the Wrangler pipeline, both of which would move crude to the US Gulf Coast, pipelines to the Pacific Coast, and more recently the possibility of a pipeline reversal that would allow crude to move to the US East Coast. Each of these projects could dramatically reduce the infrastructure constraints in the Midwest. Combined, they could dramatically change crude flows, allowing Canadian crude to flow to the Gulf Coast and West Coast, where there is considerable demand for heavy crude, and to the East Coast as well as the Midwest.

Relief of congestion at Cushing in the near term is likely to allow Canadian products to ship more easily to Gulf Coast ports as well as the Midwest, where they can access refiners with heavy crude capacity, and effectively displace the bulk of current foreign imports. Expanding access to Asian markets through tidewater ports in British Columbia will further diversify and extend the export potential for Canadian producers. A substantial price differential is available from access to Asian markets, although as a practical matter, in the short term, access to California refineries on the West Coast may occur sooner, given declining supplies of California heavy resources and consequent capacity increases for processing. The increases forecast by Alberta for oil sands expansion are forecast to be absorbed by the combination of Midwest refining capacity, West Coast refining capacity and emerging Asian markets over the period covered by this report.

In the case of Asian capacity to accept and process heavy Canadian crudes, there is a current limit of processing and refining capacity. As more supply is available at competitive prices, new investment in these facilities is likely. Competition with lighter Arabian crudes can result in price discounts that would reduce the estimates of the differential available today.

In sum, the differential captured in this study represents a substantial premium for Canadian producers of heavy oil. Worldwide, demand for oil and derivatives is likely to grow for some time into the future. Access to this product will be valuable not only for the principal client, the US, but for growing economies that develop the capacity for refining heavy oil products. Currently this capability is limited in the largest growth market, China, but this is likely to change in the future. Diversifying the industry supply chain to be able to address these future markets is certainly in the national interest, a fact that is recognized by pipeline producers in current applications. Ultimately, the most effective and efficient pricing schemes for Canadian producers will be those based on world price equivalency, which has been distorted and underrepresented in recent years. This report identifies the magnitude and location of these distortions.

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