Looking south

A Canadian perspective on the US Gulf Coast heavy oil market

3 April 2018

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Canadian Oil Sands Dialogue | Strategic Report

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About this report

Purpose. Since 2009, IHS Markit has made research public on issues surrounding the development of the Canadian oil sands. More heavy, sour crude oil (heavy oil) from the oil sands is expected to supply the United States and specifically the US Gulf Coast (USGC) region. The USGC is home to the largest concentration of complex heavy crude oil refineries in the world—an ideal match for growing Canadian heavy supply from the oil sands. This is the first of two reports that will explore the long-term relationship potential between USGC heavy oil refiners and upstream oil sands heavy oil suppliers.

Context. This report is part of a series of reports from the IHS Markit Canadian Oil Sands Dialogue. The dialogue convenes stakeholders to participate in an objective analysis of the benefits, costs, and impacts of various choices associated with Canadian oil sands development. This report is part one of two reports exploring the long-term relationship between Canadian heavy oil production and US heavy, sour demand.

This report and past Oil Sands Dialogue reports can be downloaded at www.ihsmarkit.com/oilsandsdialogue.

Methodology. IHS Markit conducted extensive research and analysis on this topic, both independently and in consultation with stakeholders. IHS Markit has full editorial control over this report and is solely responsible for its content (see the end of the report for the IHS Markit team).

Structure. This report has five sections.

- Introduction
- The rise of Canadian heavy oil
- The US Midwest: The largest market for Canadian oil
- The USGC: The world's largest heavy oil market
- Importance of a Canadian offshore hedge

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Key implications

Canada is the world's largest producer of heavy, sour crude oil (heavy oil) and the United States is the world's largest consumer. With demand satisfied in the US Midwest, increasing volumes of Canadian heavy oil have begun to reach the US Gulf Coast (USGC)—which accounts for half of all US heavy oil demand. Heavy oil supply from Canada competes with production from Mexico and Venezuela, and the USGC market is not limitless. This report explores the relationship potential between USGC refiners and Canada's oil sands.

- **The United States and, in turn, the USGC is the world's largest consuming market for heavy oil.** Heavy oil processing capacity allows refiners to optimize operations over a greater range of crudes, which include lower-cost heavy crude oil. In 2017, the US market consumed more than 5 MMb/d of heavy oil, with nearly 3 MMb/d in the USGC region alone. More than 90% of this demand was met by imports.

- **Canadian supply has begun to reach the USGC at a timely moment when supply from key competitors, such as Mexico and Venezuela, is waning.** Declining availability from traditional sources of heavy oil imports has provided opportunities for Canadian crude oil of similar quality. Conversely, USGC refiners have benefited from greater access to growing Canadian supply.

- **Canadian heavy oil is a good substitute for Latin American heavy oil, but the two are not identical.** Subtle differences, such as a higher proportion of lighter ends in diluted bitumen (the dominant source of Canadian heavy oil growth) compared with Mexican Mayan crude, can present a challenge for some refiners looking to run greater levels of Canadian crude. Overcoming these differences is not insurmountable but may require greater incentives for refiners.

- **From the Canadian perspective, there are risks to overreliance on the US market.** US supply and demand fundamentals exert much influence on the value of Canadian crude oil. Should the USGC heavy oil market become more competitive in the future, Canadian heavy oil may have to compete more aggressively on price.

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A Canadian perspective on the US Gulf Coast heavy oil market

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Introduction

Since 2000, Canadian crude oil production has grown more than 2 MMb/d—the third-fastest pace in the world behind Russia and the United States—faster than Saudi Arabia, Iran, and Iraq. In 2017, Canada was the fifth-largest producer of crude oil globally and the single-largest source of crude oil imports to the United States. In 2017, the United States imported more than 3.4 MMb/d from Canada—more than all of OPEC combined.[2]

Canada's growth has been propelled by investment in the oil sands, and heavy, sour crude oil (heavy oil) has dominated Canadian supply output. In 2017, Canada produced more than 4.1 MMb/d, about half of which was heavy oil.[3]

Oil sands production growth is on course to decelerate, but significant gains are still anticipated. By 2025, oil sands supply may be almost 1.4 MMb/d greater than in 2017—reaching 4.5 MMb/d—with more than 90% of the growth in supply being heavy oil.

The dominance of heavy oil growth has allowed Canadian crude oil exports to complement US light, tight oil growth. Tight oil supply primarily meets the needs of less complex light, sweet crude oil refineries (displacing offshore imports of light, sweet crude). Heavy oil supply from Canada meets the needs of more complex heavy crude oil refineries. Access to growing US and Canadian crude oil—light and heavy—has, in turn, made North America more energy self-sufficient, shoring up domestic refining runs and increasing continental energy security.

The single-largest market for Canadian crude oil exports has been the US Midwest. In 2017, IHS Markit estimates the US Midwest consumed nearly half of all Canadian crude oil exports. Conversely, over two-fifths of the crude oil processed in the US Midwest came from Canada, three-quarters of which was heavy oil. However, the US Midwest may be nearing its limit to consume increasing volumes of Canadian supply. More Canadian crude oil is now flowing to the US Gulf Coast (USGC) region. The USGC is home to the world's largest concentration of heavy oil refineries—an ideal match for growing Canadian output. However, Canada's expanding reliance on the US market brings challenges and risks. This report will explore the potential for further Canadian and US oil market integration.

Throughout this report, some common terms are used to describe the oil sands, refining, and crude oil quality. These are discussed in the boxes "Canadian oil sands primer" and "Heavy oil 101."

1. Special thank you to Steve Fekete, Managing Director at IHS Markit.

2. This estimate is based on the first 10 months of 2017 as derived from the US Energy Information Administration's (EIA) "US Imports by Country of Origin," 31 January 2018, retrieved 16 February 2018.

3. It is important to note that supply exceeds production in Canada, because oil sands producers that choose to market heavy crude oil must dilute bitumen with lighter hydrocarbons. Often, condensate or pentane plus hydrocarbons are imported from the United States and elsewhere to meet demand. On a supply basis, Canada marketed more than 4.3 MMb/d in 2017. Because of this blending, about two-thirds of supply is heavy oil. Although oil sands are the single-largest source of Canadian heavy oil, they are not the only Canadian source.

Canadian oil sands primer

The immensity of the oil sands is their signature feature. Current estimates place the amount of crude oil that can be economically recovered from the Canadian oil sands at 166 billion bbl, making oil sands the world's third-largest proven oil reserve (after Saudi Arabia and Venezuela).

The oil sands are grains of sand covered with water, bitumen, and clay. The "oil" in the oil sands is bitumen, an extra-heavy, sour crude oil with high viscosity. Raw bitumen is semisolid at ambient temperature and cannot be transported by pipeline. It must first be diluted with light oil or converted into a synthetic light crude oil. Different grades of crude oil are produced from bitumen.

Bitumen blends. To meet pipeline requirements, bitumen is diluted with lighter hydrocarbons (often natural gas condensates) into a bitumen blend. The blend density is between 923 kg and 940 kg per cubic meter (20–22° API gravity), making it comparable to other heavy crudes, such as Mexican Maya. The most common bitumen blend is diluted bitumen (dilbit)—typically about 70% bitumen and 30% lighter hydrocarbons. We expect the vast majority of oil sands supply growth in the future to be bitumen blends, specifically dilbit.

Synthetic crude oil (SCO). SCO is produced from bitumen via refinery conversion units that turn very heavy hydrocarbons into lighter, more valuable fractions from which gasoline and diesel are manufactured. These units are called upgraders. SCO resembles light, sweet crude oil.

Heavy oil 101

Crude oil is not homogeneous. It can vary depending on density (light or heavy) and quality (the presence of impurities such as sulfur, giving rise to terms like sweet or sour). Density is by far the most common metric of quality, which is measured according to API gravity. Light crude oil generally has an API gravity of 32° or higher. Heavy crude oil has an API gravity below 24° (with the API gravity for extra-heavy crude oil below 10°). Medium crudes have an API gravity between light and heavy crudes. The sulfur content for sweet crude oil is less than 1wt%, with levels for sour crude oil exceeding this amount.

Differences in density result from the composition of hydrocarbons found in a given crude oil. Different hydrocarbon molecules have different properties. Generally, the longer or more complex the hydrocarbon, the "heavier" the molecule and the higher its boiling point. The greater the share of these molecules in a given crude oil, the heavier the oil is, and more energy is required to convert the oil into higher-value refined products, such as gasoline.

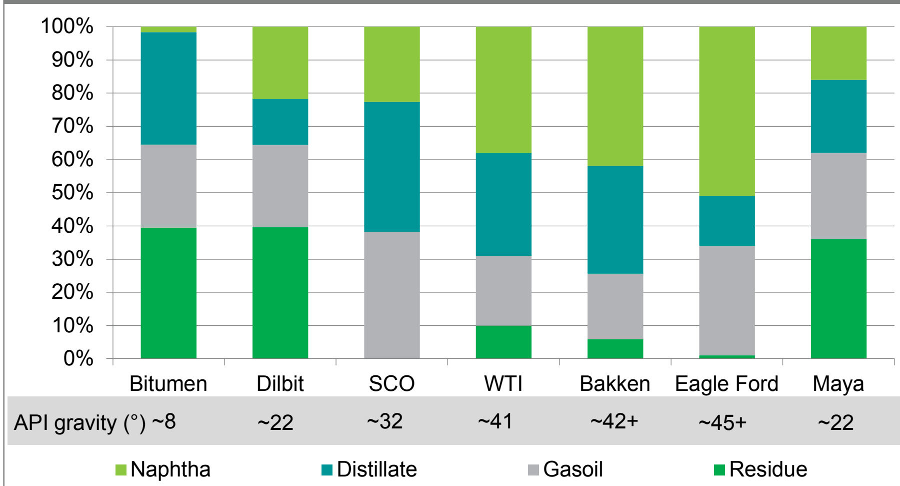
Different crude oils will vary in their ability to be converted into different refined products. Within any given barrel of oil, there are various fractions, or groupings, of hydrocarbons that distill or boil at distinct temperature ranges. Naphtha is the lightest fraction and boils at a lower temperature. Gasoline is generally derived from naphtha. Kerosene (jet fuel) and diesel are found in the distillate range, boiling at higher temperatures between 180°C and 350°C. Vacuum gasoil and residue are viscous materials that boil between 350°C and 550°C, respectively. These fractions require additional processing (via catalytic or thermal processes) to be converted into lighter fractions of distillate and naphtha, which can then be converted into higher-value products. Less complex refineries (facilities that lack additional heavy crude oil processing technology) will not be able to process these heavier fractions into lighter products. As a result, they will pay a premium for lighter crude oil. By contrast, more complex refineries—facilities that have invested in specialized units capable of converting heavy fractions to light products—will seek out crude oil with larger fractions of heavy molecules. Because of the complexity and cost required to process heavier crude oils, they typically are cheaper than lighter crude oil.

The rise of Canadian heavy oil

Bitumen found in the oil sands is an extra-heavy, sour crude oil and features a large fraction of residue (nearly half) (see Figure 1). To convert a barrel of oil from the oil sands (the residue specifically) into a refined product, such as gasoline or diesel, refiners need to have made large capital investments in specialized heavy crude oil processing units. If refiners have not made these investments, they will be unable to convert many of these heavier molecules into higher-value refined products and will have to sell lower-value intermediate products to facilities with the ability to handle them.

Figure 1

Assay of key crude oils



Note: Crude assays will vary. Values are approximations and will vary by cut point and reservoir quality, which does vary across a play and over time. Estimate assembled from various sources and adjusted based on feedback.
Source: Derived and adapted from IHS Markit, US EIA, CrudeMonitor.ca

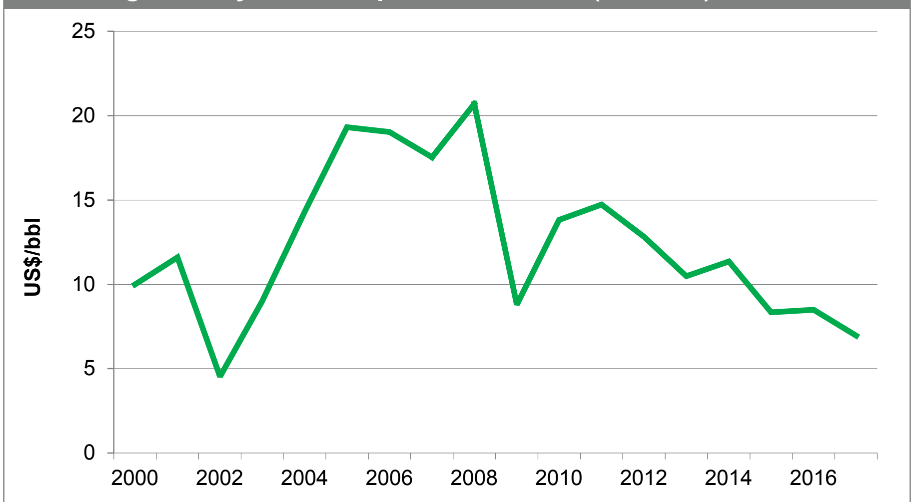
Over time, refiners tailor their operations toward available crude oil as historical sources decline and new sources arise. However, the decision to invest in heavy oil processing capacity is significant. Heavy processing units, such as a delayed coker (vessels capable of reaching the temperature and pressure required to convert residue into lighter fractions), typically cost well over US$1 billion.[4] Refiners will weigh this cost against the estimated savings from being able to process lower-value heavy crude oil over continuing to purchase and run higher-priced lighter crude oils. The price differential between light crude oil and heavy crude oil is known as the light-heavy differential.

The difference in price between light and heavy crude oil is set by the relative demand for these two general categories of crude oil. This is influenced by the demand for light and heavy refined products as well as the availability of heavy conversion capacity.

Preceding the US tight oil boom, the availability of heavy oil was on the rise while light, sweet crude oil was in decline. This contributed to a wider price difference between light and heavy crude oil, which supported investments in more complex refining capacity (see Figure 2). This occurred first in the USGC, through a number

Figure 2

Global light-heavy crude oil price differential (2000–17)



Note: Based on difference between Louisiana Light Sweet and Maya FOB Mexico.
Source: Argus Media, IHS Markit

4. Delayed cokers use high temperature and residence to crack the complex molecules found in residue into lighter fractions, which can then be converted into higher-value refined products.

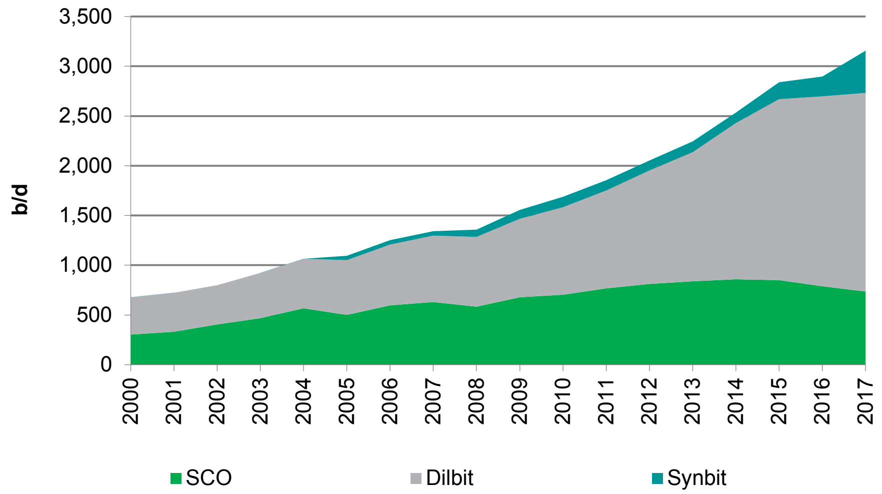
of JVs and crude oil supply arrangements, to meet growing supply from Latin America, then later in the US Midwest to take advantage of growing volumes of heavy oil from Canada.

Investments were also made in the oil sands for economic and technical reasons to convert the large fraction of residue in bitumen into lighter fractions. This was called upgrading. The resulting ("bottomless") SCO product could then be marketed to refiners that lacked heavy oil processing capacity.[5] However, over time, new forms of extraction, which often lacked the scale of mining operations, and the appreciation of the cost to construct upgraders reduced interest in upgrading (but has not eliminated it).[6]

Heavy oil growth, particularly bitumen blends and specifically dilbit, has outpaced SCO supply growth in the Canadian oil sands (see Figure 3). In 2012, bitumen blends overtook SCO as the dominant source of oil sands supply. This trend was helped along by the renaissance of US tight oil production, which provided an ample supply of light, sweet crude oil. This has diminished the price difference between light and heavy crude oil and, in turn, the economic incentive to further expand bitumen upgrading in Canada.

Figure 3

Canadian oil sands supply by major marketed product



Note: Synbit is a roughly 50/50 blend between SCO and bitumen.
Source: IHS Markit

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The US Midwest: The largest market for Canadian oil

Crude oil production in western Canada has long surpassed regional demand, and increasing volumes have found a home in the United States. In 2017, Canada produced 4.1 MMb/d in total, and the oil sands accounted for about 2.6 MMb/d. On a supply basis, which accounts for Canadian imports of condensate (from the United States and offshore) used to create dilbit, Canada exceeded 4.3 MMb/d in 2017, with oil sands topping 3.1 MMb/d.

The single-largest market for Canadian oil of all grades (light to heavy) continues to be the US Midwest. However, volumes are increasing in the USGC region, which is home to the world's largest concentration of heavy, sour complex refining capacity. These two markets—key for current and future Canadian heavy crude oil supply—account for nearly three-quarters of total US crude oil refinery demand, processing over 12 MMb/d in 2017, one-third of which, or over 4 MMb/d, was heavy oil.

The rise of Canadian imports, until recently, had been supported by the historical decline in US supply. From the mid-1970s until the dawn of the tight oil revolution, the availability of domestic crude oil for refiners steadily fell. US Midwest refineries historically processed US domestic crude oils and foreign imports delivered inland via pipeline from ports in the USGC. Refiners in the US Midwest invested in expanding heavy crude oil processing capacity to access growing volumes from Canada. Over the past decade (2008–17), heavy crude

5. SCO may be referred to as bottomless because nearly all the residue has been converted to lighter fractions (see Figure 1).

6. Steam-assisted gravity drainage technology played a major role in enabling production of a marketable heavy crude oil, which was not possible for mined bitumen using naphthenic froth separate processes. More recently, advances in paraffinic froth treatment have allowed the development of mines without upgraders. For more information, see the IHS Markit Strategic Report *A New Look: Extracting economic value from the Canadian oil sands*.

oil processing increased by about 500,000 MMb/d. Over the same period, a combination of growing US domestic tight oil and Canadian supply collapsed offshore imports into the US Midwest by 400,000 b/d, to near negligible levels today. Nearly every barrel imported into the US Midwest today comes from Canada. In 2017, the region consumed 3.6 MMb/d—with 90% split almost equally between Canadian and domestic supply—and more than one-third was heavy oil from Canada.[7]

With supply overtaking US Midwest demand, increasing volumes of heavy oil from Canada must find a new home: the most logistically approximate and technically suited is the USGC.

The USGC: The world's largest heavy crude oil market

The USGC region is one of the largest refining centers in the world and home to the world's largest concentration of heavy oil processing capacity. In 2017, the region processed nearly 8.7 MMb/d of crude oil, of which 2.8 MMb/d was heavy oil. Although the USGC has the potential to become the largest market for Canadian crude oil exports, it is not limitless, and there are challenges that may come at a cost for Canadian producers.

Light, tight oil to limit demand growth for heavy, sour crude

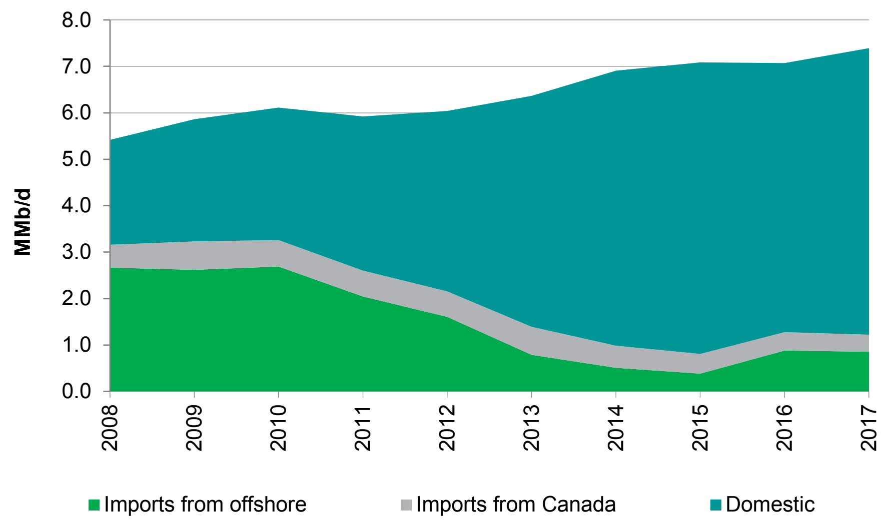
Over a very short period—since the start of the decade—the US oil market has changed remarkably. The revolution in tight oil has ushered in an era of abundant domestic supplies of light, sweet crude oil. Meanwhile, the output of traditional sources of heavy crude oil imports to the United States—namely Venezuela and Mexico—has fallen. Lower prices accelerated the decline of Mexican Mayan heavy oil and exacerbated the economic and political crisis in Venezuela, which, in turn, has contributed to greater production losses. These factors have contributed to a reduction in the light-heavy crude oil differential globally, reducing the economic incentive to invest further in expanding downstream heavy oil processing capacity (as well as reducing the incentive to upgrade in Canada).

IHS Markit expects that growing supplies of light, tight oil in the United States will encourage refiners to invest in consuming more of it. Indeed, over the past decade (2008–17), total runs of light, sweet crude increased 1.1 MMb/d, while US domestic supply growth displaced 1.8 MMb/d of offshore imports of similar quality (see Figure 4).

Yet, although investments to increase heavy oil processing capacity may have diminished with the rise of light, tight oil, existing heavy processing capacity is not expected to be idled.[8] Heavy crude oil processing capacity, such as cokers, represents a significant

Figure 4

US consumption (refinery runs) of light, sweet crude oil by region



Source: IHS Markit

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7. The US Midwest imports a range of crude oils from Canada, from light to heavy, but heavy oil is—by far—the largest share.

8. Investments are expected to expand the "top end," such as naphtha handling, which is found at greater quantities in tight oil and even oil sands dilbit than historical supply in the region.

investment and once installed allows refiners to process lower-value, and thus lower-cost, feedstock. Once this capacity is operational, refiners will not want to idle it.

Indeed, from 2008 to 2017, USGC heavy oil consumption increased by more than 750,000 b/d, while equivalent offshore imports declined 160,000 b/d. Although the availability of traditional imports from key Latin American suppliers has been declining, increased availability and access to Canadian heavy crude oil has thus far been able to more than offset these declines, resulting in greater refinery runs.

Canadian heavy crude oil will have to compete

Despite logistical challenges facing Canadian supply, it has begun to reach the USGC at a time when supply from key competitors is waning.[9] Over the past five years, production from key sources of historical heavy oil imports, such as Mexico and Venezuela, has declined by nearly 1 MMb/d. This has helped to make growing Canadian heavy oil supply an attractive substitute.

Although Canadian imports are of similar quality as Latin American crudes, they are not identical. Compared with Mexican Mayan, oil sands dilbit (from the Athabasca region specifically)—the dominant source of Canadian heavy, sour supply growth—has similar fractions of vacuum gasoil and residue but larger fractions of naphtha and less distillate (see Figure 1). Given the relatively larger fractions of heavy and light, the distillation of dilbit is referred to as "dumbbell" given the nonhomogeneous boiling curve of the crude. Refiners can manage some differences between crudes by blending various crude oils as well as making minor modifications to existing processing units. However, all things being equal, there is a point when more extensive modifications will be required to better tailor facilities toward dilbit. Should dilbit exports continue to dominate, loosely speaking, volumes under 1.2 MMb/d should be readily accommodated with minor modifications (based on available residue processing capacity and corresponding light ends handling capacity at these refineries). However, as volumes exceed this level, more extensive modifications may be required.[10]

As volumes build, USGC refiners may require greater incentives to process increasing quantities of Canadian heavy crude oil over entrenched offshore competition. This then comes down to the availability of traditional competitive sources of supply and the price. Should Latin American heavy oil supply continue to decline, this would push refiners to more aggressively seek out alternative sources of heavy oil supply—to Canada's benefit. However, should Latin American supply prove more resilient, Canadian crude oil may have to compete for space sooner. For crude oil, competition is about price; and in the absence of an alternative outlet market, this implies that Canadian crude oil would have to discount or price under crude oil of comparable quality to encourage refiners to make the necessary modifications.

The degree of the discount may be within a few dollars, but it could translate to a reduction in the economic value to Canada. Moreover, with millions of barrels per day of exports, the discount would add up. The theoretical price floor is set by the cost to move Canadian crude oil farther afield to more distant markets, including refiners not currently connected by pipelines to the Houston refinery complex.[11]

9. See the IHS Markit Strategic Report *Pipelines, Prices, and Promises—The story of western Canadian market access*.

10. To be certain, any estimate of crude quality fit is an approximation. There is variability in bitumen and therefore dilbit quality across the oil sands (as with any crude-producing region), which will influence the potential modifications that may be required as greater volumes reach the USGC. For example, dilbit from the Cold Lake region is a closer match to Mexican Maya than Athabasca dilbit. The estimate presented in this report is based on Athabasca dilbit because the majority of growth is expected to come from Athabasca in the IHS Markit outlook. In addition, creation or marking of alternative blends that use less natural gas condensate (the principal contributor to the large naphtha share in dilbit) or refiners rejecting naphtha could also affect refiners' abilities to process greater volumes of heavy oil from Canada. All of these factors—bitumen quality, naphtha rejection, and creation of alternative blends—will influence the volume and type of modifications that may be required to substitute greater volumes of Canadian heavy oil for traditional offshore sources of heavy oil.

11. Planned infrastructure to deliver Canadian heavy oil into the USGC would provide access from Houston/Port Arthur to New Orleans. Although this provides access for the majority of the heavy oil capacity in the region, operations farther afield, such as in Mississippi, exist.

Importance of a Canadian offshore hedge

The United States, particularly the US Midwest and now the USGC, is expected to remain the most significant crude oil export market for Canada. With traditional sources of offshore heavy oil supply in decline, Canadian supply has become an attractive substitute. All indications are that heavy crude oil trade will grow between Canada and the United States—an effective match to the benefit of both parties. IHS Markit estimates that current runs of Canadian crude in the USGC are already in excess of 800,000 b/d—far greater than headline EIA import data would indicate due to commingling, storage, and internal transfers within the United States.[12] By 2020, IHS Markit estimates that with increased rail movements, runs of Canadian heavy could top 1.2 MMb/d—a full one-third of the region's heavy oil market.

Although the United States provides security of demand for Canada, there are risks to Canada from overreliance. The IHS Markit forecast assumes the completion of all three remaining major long-distance export pipelines: Enbridge Mainline expansion (Line 3 Replacement Project, specifically), TransCanada Keystone XL, and Kinder Morgan Trans Mountain Expansion Project.[13] The first two pipelines would permit increased flows of western Canadian crude oil to the USGC; the Trans Mountain pipeline would deliver Canadian crude oil offshore via a port on Canada's west coast. If the Trans Mountain pipeline continues to meet delays, or Canadian or competitive heavy oil supply is more prolific than anticipated, Canada may have to compete more aggressively for market share in the United States. In this instance, Canadian crude oil may have to discount to incentivize refiners to make even greater modifications to better tailor their facilities to Canadian heavy oil supply and/or displace greater quantities of offshore imports.

Alternative diversification strategies can help mitigate some of these risks. These could involve customizing oil sands blends or developing upstream partial processing technologies that would result in the marketing of a greater range of crude oil qualities. This would allow oil sands to meet the needs of more US refiners, expanding market share and integration with the US market. Yet, given the scale of Canadian heavy oil supply today and anticipated growth, these solutions would not remove the risk and would still take considerable investment and time. For Canada—the fifth-largest oil producer in the world—its almost singular reliance on one market is unique in the world, and there are associated risks.

12. EIA tracks overland crude oil imports when they "break bulk," which means when the crude oil is unloaded or leaves the pipeline. IHS Markit believes that Canadian heavy oil imports may be "stopping off" at Cushing, which would result in a reported delivery into PADD 2 as opposed to PADD 3.

13. See the IHS Markit Strategic Report *Pipelines, Prices, and Promises—The story of western Canadian market access*.

IHS Markit team[14]

Kevin Birn, Vice President, IHS Markit, is part of the IHS Markit North American Crude Oil Markets team, leads the IHS Markit Oil Sands Dialogue. Mr. Birn is responsible for a team of oil market analysts focused on western Canada. Mr. Birn has authored more than 40 reports associated with the development of the Canadian oil sands. His expertise includes Canadian oil sands development, oil sands cost and competitiveness, crude oil markets, crude oil transportation logistics, greenhouse gas intensity of crude oil, and Canadian energy and climate policy. Mr. Birn has contributed to numerous government and international collaborative research efforts, including the 2011 National Petroleum Council report *Prudent Development of Natural Gas & Oil Resources* for the US secretary of energy. Prior to joining IHS Markit, Mr. Birn was a senior economist with the Government of Canada and a partner in a software firm. Mr. Birn holds undergraduate and graduate degrees from the University of Alberta. He is based in Calgary.

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14. Special thank you to Steve Fekete, Managing Director at IHS Markit.

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