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EXECUTIVE SUMMARY

CAPP annually publishes a long-term outlook for Canadian crude oil production. This year, our forecast has been extended by five years to 2030. Growth in conventional oil production is even stronger than was expected last year, however, oil sands remain the dominant component of future production. This longer term outlook predicts total Canadian production will exceed 6 million b/d at the end of this period. Western Canadian crude oil producers need to find new markets for their expanding production. Eastern Canada, which currently imports over half of its oil from offshore foreign suppliers, is a prime candidate. Other market opportunities include increasing the share of the U.S. markets that have been traditionally served, as well as accessing new U.S. markets, particularly those located on the U.S. Gulf Coast. Beyond the confines of North America, growing economies in Asia represent a market that producers are actively pursuing. As a result of strong growth in both U.S. and Canadian oil production, pipeline capacity is expected to be tight in the next few years, requiring the need for timely expansions to provide market access. A number of pipeline projects are being proposed to connect the growing supply with the anticipated market demand.

Canadian Crude Oil Production and Supply

CAPP's 2012 outlook for western Canadian crude oil production predicts continued strong growth for the forecast period. Overall, compared to CAPP's 2011 forecast, the total Canadian outlook is higher by 885,000 b/d in 2025.

Conventional

The degree of resurgence in conventional production is even greater than we predicted last year. In 2011, conventional production, including pentanes, from western Canada grew for the first time in many years, surpassing previous expectations and is expected to grow until at least 2017.

Oil Sands

The main driver for future growth continues to be oil sands development, which is higher than previously forecast due to the addition of several new projects reflecting growing producer confidence.

Atlantic Canada

Production from offshore Atlantic Canada accounted for 9 per cent of Canada's production in 2011 and is expected to average around 220,000 b/d over the next decade. The start-up up of the Hebron project in 2017 helps to offset production declines from the existing projects.

Canadian Crude Oil Production

<table>
<thead>
<tr>
<th>million b/d</th>
<th>2011</th>
<th>2015</th>
<th>2020</th>
<th>2025</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Canadian</td>
<td>3.0</td>
<td>3.8</td>
<td>4.7</td>
<td>5.6</td>
<td>6.2</td>
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<tr>
<td>(including oil sands)</td>
<td></td>
<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Eastern Canada</td>
<td>0.3</td>
<td>0.2</td>
<td>0.2</td>
<td>0.2</td>
<td>0.1</td>
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<tr>
<td>Western Canada</td>
<td></td>
<td></td>
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<td></td>
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<td>Conventional</td>
<td>1.1</td>
<td>1.3</td>
<td>1.3</td>
<td>1.2</td>
<td>1.1</td>
</tr>
<tr>
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<td>1.6</td>
<td>2.3</td>
<td>3.2</td>
<td>4.2</td>
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</table>

Canadian Oil Sands & Conventional Production

<table>
<thead>
<tr>
<th>thousand barrels per day</th>
<th>2010</th>
<th>2012</th>
<th>2014</th>
<th>2016</th>
<th>2018</th>
<th>2020</th>
<th>2022</th>
<th>2024</th>
<th>2026</th>
<th>2028</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Sands Operating &amp; In Construction</td>
<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Conventional Light</td>
<td></td>
<td></td>
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<td></td>
<td></td>
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<td></td>
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<tr>
<td>Conventional Heavy</td>
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<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pentanes</td>
<td>1,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Eastern Canada</td>
<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Oil Sands Growth</td>
<td>8,000</td>
<td>7,000</td>
<td>6,000</td>
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<td>4,000</td>
<td>3,000</td>
<td>2,000</td>
<td>1,000</td>
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<tr>
<td>June 2011 Forecast</td>
<td>0</td>
<td>1,000</td>
<td>2,000</td>
<td>3,000</td>
<td>4,000</td>
<td>5,000</td>
<td>6,000</td>
<td>7,000</td>
<td>8,000</td>
<td>9,000</td>
<td>10,000</td>
</tr>
</tbody>
</table>
Crude Oil Markets

The production of crude oil in Canada far exceeds our domestic needs. Western Canadian producers require access to new markets for their steadily growing production.

**Eastern Canada**

Refineries located in Ontario, Québec and Atlantic Canada currently import over half of their crude oil requirements from offshore foreign suppliers. There is an opportunity for producers in western Canada to serve this market and reduce Canada’s exposure to volatile world oil markets.

**United States**

Growing domestic U.S. crude oil production will increase competition for western Canadian crude oil in various U.S. markets. Nonetheless, the U.S. Gulf Coast still represents a significant market opportunity for Canadian supplies given the huge refining complex that is in place. Based on the contractual commitments underpinning pipeline projects that would provide capacity to the Gulf Coast, western Canadian producers could supply at least 1.1 million b/d into this market by 2020. Foreign imports account for the majority of the Gulf Coast’s heavy crude oil feedstock today so heavy crude oil from western Canada is well suited to meet this market’s requirements thereby displacing imports from traditional suppliers such as Venezuela and Mexico.

The demand for western Canadian crude oil in the U.S. Midwest, Canada’s largest traditional market, is expected to rise by almost 470,000 b/d. However, the flow of crude oil into this region currently far exceeds its ability to process it and there exists insufficient takeaway capacity to transport these growing supplies beyond the Cushing, Oklahoma pipeline and storage hub. Refineries in California and Washington are expected to increase imports of foreign sourced crude oil given declining production from Alaska. Western Canadian producers can compete for this market opportunity.

2011 Canada and U.S. Crude Oil Demand by Market Region

Source: EIA, Statistics Canada

[Map showing crude oil demand by market region in 2011]
Asia

Asia represents a large new market and China, in particular, continues to emerge as a significant potential market. In 2011, it imported some 5.7 million b/d of oil.

Crude Oil Pipelines and Expansions

Growing conventional oil, including tight oil, and oil sands production has created an urgent need for additional transportation infrastructure. New pipelines, expansions to existing infrastructure and increased transportation by rail are all required to meet this need for capacity. Pipelines continue to be the dominant mode of transportation for crude oil but it takes time for pipeline infrastructure to be built or expanded.

In the short-term, crude oil transport by rail will increase sharply due to the ability to use rail capacity relatively quickly and in small increments as needed and utilizing the rail infrastructure already in place.

Canadian & U.S. Crude Oil Pipelines - All Proposals

A number of pipeline proposals to the Gulf Coast have recently been announced that will increase access by 2014 via connections to existing infrastructure and new projects. In addition to looking for increased penetration to U.S. markets, western Canadian crude oil producers are also seeking much greater market diversification through increased connectivity to Eastern Canada and world markets. This would be achieved by more pipeline capacity to the west coast, where crude oil could be shipped to the burgeoning economies of Asia. There is also much interest in improving connectivity to western Canadian supplies for all Canadians. As such, a number of projects to increase pipeline access from western Canada to eastern Canadian markets are being contemplated.
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CAPP annually publishes a long-term outlook for Canadian crude oil production. This year our forecast has been extended by five years to 2030. The decisions producers make to increase investment in order to grow supply are not made in a vacuum. Producers want to know what the market opportunities are for any increased supply and whether there will be sufficient infrastructure to provide market access. Hence, this report also provides a demand outlook for western Canadian crude oil that has also been extended out by five years, to 2020. In addition, the report includes a discussion on the existing and developing transportation options that will be required to enable the efficient flow of crude oil from supply regions to end-use markets.

The purpose of this report is to provide industry stakeholders and government agencies with a benchmark from which to compare their own outlooks of Canadian crude oil supply. Through its examination of evolving industry trends, this report is intended to contribute to stakeholders’ market analysis and facilitate decision-making in an industry that faces complex issues. Other interested parties may value the report as a reference document that reflects the latest emerging developments.

This report captures a number of interesting developments. Top of this list is the revitalization of conventional crude oil production taking place in a number of western Canadian plays. In 2011, conventional production, including pentanes, from western Canada grew for the first time in many years, significantly surpassing previous expectations. It is now expected to grow until at least 2017. Oil sands development is also higher than previously forecast due to the addition of a number of new projects. By 2025, the combined western Canadian production from both conventional and unconventional crude oil development in this forecast is about 885,000 b/d higher than last year. CAPP’s estimate of industry capital spending for oil sands development is $20 billion for 2012 compared to an estimated $19 billion spent in 2011.

Production from offshore Atlantic Canada, which in 2011 accounted for 9 per cent of total Canadian production, is expected to decline by 21 per cent in 2012. Production will remain relatively stable, averaging around 220,000 b/d until 2022, supported by production from satellite fields and the Hebron project starting up in 2017. In 2024, production falls to just over 170,000 b/d and declines steadily thereafter.

The forecasted higher growth in supply for western Canadian crude oil has resulted in increased awareness regarding the potential for pipeline constraints. The largest market for western Canadian crude has traditionally been the U.S. Midwest but future production growth requires Canadian producers to look to extend their reach and serve new markets. Avoiding constraints in transportation capacity to markets is essential to a well-functioning crude oil market and the potential for such constraints is currently one of the oil industry’s major concerns.

Growth in western Canadian and U.S. Mid-continent crude oil supply, which has taken place in the last few years, has already resulted in a market characterized by tight pipeline capacity that has seen the emergence of a number of bottlenecks. Most notable is the oversupply situation at the Cushing, Oklahoma pipeline and storage hub. In this case, pipeline capacity has been added to
transport crude from areas with growing production into Cushing while there has been no commensurate takeaway capacity from the hub added to date to take these crude oil supplies to refineries located outside of the Mid-continent. As a result, the price of crude oil in the Mid-continent has been depressed relative to global crude oil prices. For example, in the past year the price of West Texas Intermediate (WTI), a benchmark Mid-continent crude oil, has sold at a discount at times well over $20 per barrel compared to North Sea Brent, which is a light crude oil of similar quality that is sold on world markets.

1.1 Production and Supply Forecast Methodology

CAPP’s oil sands forecast is derived from its survey of oil sands producers who were asked for the following data:

a) expected production by project and phase;

b) upgraded light crude oil that would be produced;

c) amount of synthetic crude oil used as diluent required to move the volumes to market; and

d) amount of condensate used as diluent to move the volumes to market.

The survey results were then risked accordingly based on each project’s current development stage. The overall forecast was then verified for reasonableness against historical trends. There were no constraints put on the forecast due to availability of condensate or pipeline capacity.

CAPP also surveyed Saskatchewan conventional oil producers regarding their annual drilling outlook by well type (horizontal or vertical), as well as their anticipated initial production rates and declines. These survey results were subsequently incorporated with CAPP’s internal analysis of historical trends, recent announcements and discussions with industry stakeholders in order to develop CAPP’s latest conventional forecast.

1.2 Market Demand Outlook Methodology

CAPP did not make any risk adjustments to the data submitted by refiners beyond checking it for potential errors. Certain assumptions were also made based on discussions with refiners and the review of publicly available information.

The CAPP survey categorizes western Canadian crude oil into four main types as follows:

1. Conventional Light Sweet (greater than 27° API and less than or equal to 0.5% sulphur) including condensates and pentanes plus;

2. Heavy (equal to or less than 27° API) including conventional heavy, synthetic sour and crude oil blends such as DilBit, SynBit and DilSynBit;

3. Conventional Medium Sour (greater than 27° API and greater than 0.5% sulphur); and

4. Light Sweet Synthetic

For the purposes of the historical data in this section of the report, the following crude types and definitions apply:

- Sweet: crude oil with a sulphur content of less than or equal to 0.5%
- Sour: crude oil with a sulphur content of greater than 0.5%
- Light: crude oil with an API of at least 30°
- Medium: crude oil with an API of greater than 27° but less than 30°
- Heavy: crude oil with an API of 27° or less

No differentiation is made between sweet and sour crude oil that falls into the heavy category because heavy crude oil is generally assumed to be sour.
2.1 Canadian Crude Oil Production

In 2011, about 9 per cent of Canada’s crude oil production, or 273,000 b/d, can be attributed to Eastern Canada, almost all of which was sourced from offshore Atlantic Canada with some small volumes from Ontario. Most of Canada’s production, or over 2.7 million b/d, was produced in western Canada. Of this amount, 41 per cent was conventional production and 59 per cent was derived from the oil sands areas. Table 2.1 shows the forecast for total Canadian production divided between Eastern and Western Canada.

Atlantic Canada’s oil resources are located off the shores of Newfoundland and Labrador and current production results from developments in three main fields – Hibernia, Terra Nova, and White Rose. Recovery from satellite fields is expected to slow the exhibited natural decline of production from these fields. The North Amethyst field started producing in 2010 and is the first satellite field development at White Rose. First oil flowed in September 2011 from the West White Rose area, a second satellite field, which is considered to be potentially the largest of the White Rose expansions. Oil started flowing in June 2011 from the Hibernia Southern Extension development. The Hibernia Southern Extension development added 223 million barrels of new reserves.

Table 2.1 Canadian Crude Oil Production

<table>
<thead>
<tr>
<th>million b/d</th>
<th>2011</th>
<th>2015</th>
<th>2020</th>
<th>2025</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total* Canadian (including oil sands)</td>
<td>3.02</td>
<td>3.85</td>
<td>4.70</td>
<td>5.62</td>
<td>6.24</td>
</tr>
<tr>
<td>Eastern Canada</td>
<td>0.27</td>
<td>0.22</td>
<td>0.22</td>
<td>0.16</td>
<td>0.09</td>
</tr>
<tr>
<td>Western Canada</td>
<td>2.74</td>
<td>3.63</td>
<td>4.49</td>
<td>5.46</td>
<td>6.16</td>
</tr>
</tbody>
</table>

*Totals may not add up due to rounding.

Following a 3 per cent decline in 2011 due to maintenance work and well shut-in at Terra Nova, Newfoundland offshore production is forecast to decline by 21 per cent in 2012 due to the natural decline in production from Hibernia and Terra Nova, and scheduled maintenance at both Terra Nova and White Rose. Production from the Hebron field, which will be Newfoundland’s fourth standalone offshore oil project, is expected to start in 2017. Most of this oil will be around 20° API. This production accounts for the growth in production from 2017 to 2018. Costs to construct Hebron are estimated to be around $8.3 billion. Federal and provincial regulators conditionally approved development of the project on May 31, 2012.

The remainder of this report will focus on western Canada as it is the primary source of future Canadian growth. The degree of resurgence in conventional production has been even greater than we predicted last year. New drilling and completion methods have contributed to the increase of conventional crude oil production as producers have perfected hydraulic fracturing techniques coupled with horizontal drilling technologies.
Despite the resurgence of conventional production, however, supplies from the oil sands will continue to comprise the bulk of the anticipated future increases in overall crude oil production. Figure 2.1 shows the Canadian production forecast. The oil sands projects that are already currently operating or are in construction account for the growth until 2015 or 2016.

### 2.2 Western Canadian Crude Oil Production

For western Canada, relative to the 2011 report, higher production is forecast in both conventional and oil sands areas (Table 2.2). The bulk of this output originates from the Western Canada Sedimentary Basin, which covers most of the province of Alberta, northeast British Columbia, southern Saskatchewan, and parts of Manitoba and the Northwest Territories.

**Table 2.2 Western Canadian Crude Oil Production**

<table>
<thead>
<tr>
<th>million b/d</th>
<th>2011</th>
<th>2015</th>
<th>2020</th>
<th>2025</th>
<th>2030</th>
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</thead>
<tbody>
<tr>
<td>Total</td>
<td>2.74</td>
<td>3.63</td>
<td>4.48</td>
<td>5.46</td>
<td>6.16</td>
</tr>
<tr>
<td>Conventional (including condensate)</td>
<td>1.13</td>
<td>1.33</td>
<td>1.32</td>
<td>1.25</td>
<td>1.14</td>
</tr>
<tr>
<td>Oil sands</td>
<td>1.61</td>
<td>2.30</td>
<td>3.16</td>
<td>4.21</td>
<td>5.02</td>
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</table>

The new long-term forecast calls for a reversal of the ongoing decline in conventional crude oil production witnessed over the past decade or more, and instead shows growth in the near term. A vibrant drilling forecast drives production growth until around 2017 when the impact of well production declines is expected to temper the overall growth rate.

Compared to the 2011 forecast, oil sands production is higher by about 100,000 b/d for most of the forecast period due to the acceleration of some projects before becoming higher by about 480,000 b/d by 2025 due to the inclusion of additional projects.

In the last three years, there has been a significant number of direct investments made in the oil sands by Asian companies. Producers turn to overseas partners to provide capital to speed up development and to share in the risk and rewards of these projects (Table 2.3).
2.2.1 Conventional Crude Oil Production

Although much of Canada’s rise in importance in the global energy scene can be attributed to the emergence of oil sands, a significant portion of Canada’s oil production still comes from conventional production.

Conventional production is forecast to grow from 1.1 million b/d in 2011 to 1.3 million b/d by 2020, thereby reversing a long term trend of continual decline. The previous outlook for conventional crude oil declines has been eclipsed by the emergence of drilling for conventional oil that takes advantage of new production and completion technologies. A high level of drilling is expected to drive production growth until around 2017 when the impact of well production declines temper the overall growth rate. Current estimates of the ultimate potential production recoverable from conventional reserves may still be conservative as these technologies are still in their early stages. Most of the conventional production comes from Alberta and Saskatchewan and is expected to be light crude oil (Figure 2.2).

In Alberta, the combination of hydraulic fracturing and horizontal drilling is being used in an increasing number of oil plays. The most advanced plays are the Cardium in west-central Alberta, the Beaverhill Lake Carbonates near Swan Hills, the Viking in east-central Alberta and at Redwater, north of Edmonton. Emerging plays include the Alberta Bakken in the southern reaches of the province and in oil prone regions in the Duverney and Montney shale gas plays. High drilling activity in these areas will offset the steep decline in Alberta conventional production that would otherwise be expected.

Russia’s largest oil company has formed a Canadian subsidiary, RN Cardium Oil Inc., and picked up a non-operated 30 per cent equity stake in ExxonMobil’s Harmattan tight oil play near Olds, Alberta. The investment is believed to be the first by a Russian firm in Canada’s oil and gas industry, and could help to speed up development activity in the Cardium play.

Production from Saskatchewan only grew by 2 per cent in 2011, however, this growth is considered to under-represent production levels that would have occurred absent poor weather and other extraordinary conditions.
2.2.2 Oil Sands

Production from oil sands currently comprises 59 per cent of western Canada’s total crude oil production. In this forecast, oil sands production rises from 1.6 million b/d in 2011 to almost double at 3.1 million b/d by 2020 and 4.2 million b/d by 2025 and 5.0 million b/d by the end of the forecast period in 2030. If the only projects to proceed were the ones in operation or currently under construction, oil sands production would still increase by 54 per cent to 2.5 million b/d by 2020 and then remain relatively flat for the rest of the forecast. Please refer to Appendix B.1 for a detailed production data table.

Compared to CAPP’s 2011 outlook, the latest oil sands forecast is very similar but is higher near the end. In 2025, this latest forecast is higher by 480,000 b/d. With the 5-year extension of the forecast period, more projects have been included in the outlook. The higher forecast in 2025 compared to CAPP’s 2011 outlook can be attributed to some acceleration project time lines and the inclusion of additional projects that are now considered more likely to proceed due to increased industry confidence and the emergence of joint venture partnerships.

Canada’s oil sands deposits are divided into three major regions in northern Alberta. The regions are referred to as the Athabasca, Cold Lake and Peace River deposits (Figure 2.3). The Alberta Energy Resources and Conservation Board (ERCB) estimated at year-end 2010, that these areas contain remaining established reserves of 169 billion barrels.

Figure 2.3 Oil Sands Regions
Of the remaining established reserves in Alberta, 135 billion barrels, or 80 per cent, is considered recoverable by in situ methods and 34 billion barrels or 20 per cent can be recovered by surface mining. In situ recovery includes both primary methods, which are similar to those used to recover conventional production, as well as other methods whereby steam, water or other solvents are injected into the reservoir to reduce the viscosity of the bitumen, allowing it to flow to a vertical or horizontal well bore.

In 2011, 51 per cent of the total raw bitumen produced from oil sands deposits was mined. Traditionally, mined bitumen is transformed into upgraded light crude oil as part of an overall integrated operation. However, with its startup in 2012, the Imperial Kearl Lake mining project will be the first mining project to deliver diluted bitumen into the market as it does not have an affiliated upgrader. There will be additional upgrading capacity being built as a result of the North West Upgrader, which is slated to come online in 2014. This facility is owned by North West Redwater Partnership, a 50/50 joint venture between North West Upgrading and Canadian Natural Resources Limited, and would be able to upgrade some of the growing volumes of diluted bitumen available from both in situ and mining projects.

Recovery of raw bitumen using in situ methods is set to surpass production from mining methods by 2015, a year earlier than forecast in the 2011 report. Of the in situ projects currently in operation, only the Long Lake project operated by Nexen Inc. is coupled with an upgrading facility. Production from the Suncor Firebag and MacKay River projects are upgraded at Suncor’s integrated mining facilities depending on spare capacity at the upgraders and market conditions. Otherwise, the majority of in situ bitumen production is not upgraded prior to reaching markets. Recently, producers have been transporting undiluted bitumen in rail cars; the bitumen is later blended with condensate at facilities nearby the end market, prior to delivery to the refiners.
Existing mines with integrated upgrading projects in operation are listed below:

- Suncor Steepbank and Millennium Mine;
- Syncrude Mildred Lake Mine and Aurora Mine;
- Athabasca Oil Sands Project (AOSP);
- Shell Jackpine Mine; and
- Canadian Natural Resources Horizon Project.

2.3 Western Canadian Crude Oil Supply

In order to be transported by pipeline and meet refinery specifications, the production discussed in the previous section may be upgraded or blended to create a variety of crude oil types. It is these volumes that comprise the crude oil supply that is delivered to markets.

In this report, CAPP categorizes the various crude oil types that comprise western Canadian crude oil supply into four main categories: Conventional Light, Conventional Heavy, Upgraded Light and Oil Sands Heavy. Oil Sands Heavy includes upgraded heavy sour crude oil, bitumen diluted with upgraded light crude oil (also known as “SynBit”) and bitumen diluted with condensate (also known as “DilBit”). An example of DilBit would be Cold Lake crude oil, which has a density of about 930 kg/m³ (21° API) and a sulphur content of 3.6%. Blending for DilBit differs slightly by project but requires approximately a 70:30 bitumen to condensate ratio while the blending ratio for SynBit is approximately 50:50.

As previously mentioned, bitumen is so viscous that it needs to be diluted with a lighter hydrocarbon, to create a type of crude oil that meets pipeline specifications for density and viscosity. The main source of diluent is condensate that is recovered from processing natural gas in western Canada, however; the needs of growing bitumen production has exceeded this supply. In 2011, an average of almost 140,000 b/d of imported condensates, diluents from upgraders and quantities of butane, supplemented the condensate supply. This latest forecast is not constrained by the availability of condensate imports as new sources of condensate are assumed to be available to meet market requirements. Refer to Section 4.7 for additional details on existing and proposed diluent pipeline projects.

Figure 2.5 Western Canada Oil Sands & Conventional Supply
A factor that could reduce estimated diluent demand would be an increase in the number of undiluted bitumen barrels that would be transported by rail and later blended with condensate at facilities located in destination markets.

Table 2.5 shows the projections for total western Canadian crude oil supply. Refer to Appendix B.2 for detailed data. Light crude oil supply is projected to grow from 1.3 million b/d in 2011 to 1.9 million b/d in 2020 and then remains relatively flat thereafter since little new upgrading capacity is currently expected to be built. Heavy crude oil supply is projected to grow from 1.6 million b/d in 2011 to 3.0 million b/d in 2020 to more than triple the current volume in 2030, when it reaches 5.1 million b/d.

### Table 2.5 Western Canadian Crude Oil Supply

<table>
<thead>
<tr>
<th>million b/d</th>
<th>2011</th>
<th>2015</th>
<th>2020</th>
<th>2025</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total</td>
<td>2.92</td>
<td>3.89</td>
<td>4.95</td>
<td>6.18</td>
<td>6.87</td>
</tr>
<tr>
<td>Light</td>
<td>1.31</td>
<td>1.80</td>
<td>1.91</td>
<td>1.95</td>
<td>1.77</td>
</tr>
<tr>
<td>Heavy</td>
<td>1.61</td>
<td>2.09</td>
<td>3.04</td>
<td>4.23</td>
<td>5.10</td>
</tr>
</tbody>
</table>

The Upgraded Light crude oil supply includes the light crude oil volumes produced from:

- Upgraders that process conventional heavy oil, e.g., the Husky Upgrader at Lloydminster and the CCRL Upgrader in Regina;
- Integrated mining and upgrading projects, e.g., Suncor, Syncrude and Canadian Natural Resources operations;
- Integrated *in situ* projects, e.g., the Nexen Long Lake project;
- Off site upgraders, e.g., the Athabasca Oil Sands Project; and
- the North West Partnership North West Upgrader

Compared to the 2011 forecast, the overall light crude oil supply is higher due to increased conventional production. The Oil Sands Heavy category is forecast to increase from 1.3 million b/d in 2011 to 3.9 million b/d in 2025 and up to 4.8 million b/d at the end of the forecast period in 2030.

### 2.5 Crude Oil Production and Supply Summary

Compared to the 2011 outlook, western Canadian conventional production is higher by 388,000 b/d by 2025. This higher forecast is supported by higher production, mostly from Alberta and Saskatchewan, resulting from increased drilling of horizontal wells that have higher initial production rates than traditional vertical wells. Oil sands production is higher by 478,000 b/d resulting from accelerated project time lines and the addition of new projects that industry has reported in the survey.

Production from offshore Atlantic Canada will remain relatively stable for most of the forecast and averages around 220,000 b/d until 2022, supported by production from satellite fields and the Hebron project starting up in 2017. In 2024, production falls to just over 170,000 b/d and declines steadily thereafter.

Overall, compared to CAPP’s 2011 forecast, total Canadian outlook is higher by 885,000 b/d by 2025.
The production of crude oil in Canada far exceeds its domestic refining capacity. This chapter discusses the outlook for the consumption of Canadian crude oil in both markets that have been traditionally served by this supply and new markets that may also be potentially served as more transportation infrastructure is developed. Figure 3.1 shows the demand for crude oil in the major refining regions in Canada and the U.S. The U.S. Gulf Coast provides the most significant opportunity for Canadian supplies for market diversification in North America. In 2011, the U.S. Gulf Coast imported some 4.8 million b/d from non-Canadian sources.

**Figure 3.1** Canada and U.S. Market Demand for Crude Oil in 2011 by Source

Source: EIA, Statistics Canada
In 2011, western Canada supplied 2.9 million b/d to various markets. Domestic demand for western Canadian crude oil was 878,000 b/d and the remaining supply of over 2.0 million b/d, or 70 per cent, was exported (Figure 3.2). PADD II which comprises the U.S. Midwest is the largest regional market for western Canadian crude oil.

### 3.1 Canada

Only about 60 per cent of the crude oil processed in Canada is sourced from domestic production since refineries in eastern Canada have limited access to western Canadian crude oil supplies. The current oil pipeline network exiting western Canada is connected to refineries in western Canada and Ontario. According to Statistics Canada, Québec processed small volumes of western Canadian crude oil in 2011. This would be the first year since 1999 that this has occurred. With no direct pipeline access, these volumes were either delivered by rail or truck.

In 2011, Canadian refineries processed 878,000 b/d of western Canadian crude; 111,000 b/d of crude oil produced in eastern Canada; and 680,000 b/d of foreign imports. The Canadian demand for western Canadian crude oil is expected to increase to 978,000 b/d by 2020 with planned refinery expansions and future transportation infrastructure developments.

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**Figure 3.2** Market Demand for Western Canadian Crude Oil: Actual 2011 and 2020 Additional

thousand barrels per day

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Non-US

35 [unknown]

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Sources: CAPP, EIA, NEB, Statistics Canada
Note: 2011 demand exceeds available supply by 16,000 b/d likely due to factors such as inventory adjustment and data discrepancies in information collection.
3.1.1 Western Canada

The eight refineries located in western Canada exclusively process western Canadian crude oil. These refineries have a total refining capacity 632,000 b/d. In 2011, they refined some 576,600 b/d of crude oil and this volume is expected to increase to 632,800 b/d by 2020 (Figure 3.3). Future additional western Canadian crude oil receipts are related to expansion plans for the Consumers’ Co-operative refinery, located in Regina, Saskatchewan and the start-up of the North West Redwater Partnership North West Upgrader. The Moose Jaw refinery in Moose Jaw, Saskatchewan produces mostly asphalt while the other refineries manufacture a wide range of petroleum products.

Figure 3.3 Western Canada: Forecast Western Canadian Crude Oil Receipts

3.1.2 Ontario

There are four refineries located in Ontario (excluding the Nova Chemical refinery and petrochemical complex in Sarnia) with a total refining capacity of 393,000 b/d. They primarily process western Canadian crude oil but also refine some imported crude oil and some volumes from Atlantic Canada. The supply from the latter two sources arrive on the Atlantic seaboard by tanker and are then transported through the Portland-to-Montréal Pipeline before being transported on the Enbridge Montréal-to-Sarnia Pipeline (Line 9). Enbridge has applied to the NEB to re-reverse the direction of the Line 9 segment from Sarnia to Westover, Ontario to flow eastward. Refer to Section 4.5 for details on oil pipelines to Eastern Canada. If approved, there could be some increase in receipts of western Canadian crude oil in the region from 2013 onward as Imperial’s refinery in Nanticoke, Ontario would be able to receive greater volumes of western Canadian crude oil. Ultimately, the refineries will select their feedstock from a variety of sources based on both availability and price (Figure 3.4).

According to Statistics Canada, Ontario refineries received 351,700 b/d of crude oil in 2011 from the following sources: Western Canada (298,300 b/d or 84.8 per cent); Eastern Canada (1,400 b/d or 0.4 per cent); North Sea (18,000 b/d or 5.1 per cent); United States and Mexico (14,000 b/d or 4.0 per cent); and other foreign sources (20,000 b/d or 5.7 per cent).

Figure 3.4 Ontario: Forecast Western Canadian Crude Oil Receipts

3.1.3 Québec

The refineries in Québec process crude originating from both Atlantic Canada and foreign sources. However, Statistics Canada reported average crude oil receipts from western Canada for June and July in 2011 of 16,000 b/d. Québec has two refineries with a combined capacity of 402,000 b/d. These refineries are configured to process mostly light crude oil. If Enbridge’s Line 9 Re-reversal proposal obtains regulatory approval to flow east all the way to Montréal as proposed in Enbridge’s second project on Line 9, these refineries would have access to the growing light oil production from western Canada and the U.S. Bakken in Montana and North Dakota.
Once crude oil reaches Montréal, companies could barge oil from there to Québec City, and potentially even ship it by rail to Saint John, New Brunswick.

Suncor has reported that it continues to assess the feasibility of building a coker at its Montréal refinery. If this project is ultimately developed, there would be increased demand for heavy crude oil in this region.

The Atlantic refineries represent a possible additional outlet for western Canadian crude oil but the transportation cost for these refineries to access these supplies would be a major consideration given the lack of infrastructure. These refineries have a total refining capacity of 497,000 b/d and currently source crude oil from a number of global suppliers. In May 2012, Imperial announced that its Dartmouth refinery will be put up for sale and potentially converted to an oil terminal or permanently shutdown, thereby decreasing the refining capacity in this market. A final decision will be made in May 2013.

### 3.2 United States

The United States is the world’s largest oil market with a total refining capacity of almost 18 million b/d. Since 2004, Canada has been the largest exporter of crude oil to the U.S. The U.S. demand for western Canadian crude oil supply is expected to reach 3.7 million b/d in 2020 assuming the proposed infrastructure receives regulatory approval to connect growing western Canadian supplies to the large U.S. Gulf Coast market.

In 2011, Canada exported over 2.2 million b/d to the U.S., which was 12 per cent more than in 2010 and was equivalent to almost 25 per cent of total U.S. imports. Of these volumes, 2.0 million b/d was sourced from western Canada. The next largest sources of imports to the U.S. were Saudi Arabia, Mexico and Venezuela. Western Canadian production could continue to capture an even larger share of U.S. imports as it replaces volumes currently supplied by these countries. A number of factors in the near term are expected to reduce supplies available to the U.S. from these sources. These include: declining production, increased domestic consumption and the diversion of supplies to Asia.

The U.S. Department of Energy divides the 50 states in the U.S. into five Petroleum Administration for Defense Districts or PADDs (Appendix C). The PADDs were originally delineated during World War II for oil allocation purposes and remain the convention for describing U.S. market regions.

#### 3.2.1 PADD I (East Coast)

PADD I is located along the east coast of the United States with refineries in Delaware, Georgia, New Jersey, Pennsylvania, and West Virginia. There are nine refineries with a total refining capacity of 1.1 million b/d. As shown in Table 3.1, a number of refineries have closed in the past few years.

In 2011, imports of foreign crude oil by refineries in PADD I totaled 1.1 million b/d, which is virtually unchanged from 2010. About 66 per cent of these volumes were light sweet crude oil (Figure 3.5). Two refineries located in Pennsylvania were idled in the latter part of 2011. However, since then the Phillips 66 refinery in Trainer was purchased by Delta Air Lines with the transaction to close in the first half of 2012; however, a re-startup schedule has not yet been announced. Since these refineries processed light and medium crude oil, lower imported volumes of light crude oil in 2012 versus 2011 can be expected. Higher imports of heavy crude oil are anticipated since PBF Energy’s Delaware City refinery, which processes primarily heavy oil, started up again in October 2011. The refinery had previously been idled since November 2009.
The EIA noted that the closed and idled capacity on the east coast can be replaced with increased refining capacity in other regions. However, there are transportation constraints that may hinder the delivery of refined products to east coast markets that currently rely on local refining capacity. Ultra-low sulphur diesel fuel will be the most challenging product to replace as there are few alternative supply sources outside of the U.S. Gulf Coast.

Transportation constraints may also hamper the movement of products through Pennsylvania and into western New York, areas that are currently supplied by pipelines originating in the Philadelphia area refinery complex. The industry may not be able to overcome all of the logistical challenges in the Northeast for a year or more, as infrastructure changes will be necessary to accommodate the changing product flows.

With a full year of net refining capacity lost due to refinery closures, an overall decline in imports and total volumes processed in PADD I can be expected. PADD I imported 223,800 b/d of crude oil from Canada. About 58,600 b/d was sourced from western Canada and was primarily delivered to the United refinery in Warren, Pennsylvania. NuStar Energy has reported its intention to process 5,000 b/d to 10,000 b/d of Canadian crude oil at its asphalt refinery in 2012. This oil would be transported by rail.

### Table 3.1 Summary of Refinery Closures/Expansions in PADD 1

<table>
<thead>
<tr>
<th>Operator</th>
<th>Location</th>
<th>Current Capacity (thousand b/d)</th>
<th>Scheduled In-Service</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sunoco</td>
<td>Eagle Point, NJ</td>
<td>150 (loss)</td>
<td>Feb 2010</td>
<td>Closed; asphalt refinery</td>
</tr>
<tr>
<td>Western Refining</td>
<td>Yorktown, NJ</td>
<td>70 (loss)</td>
<td>Sep 2010</td>
<td>Closed; asphalt refinery</td>
</tr>
<tr>
<td>Phillips 66</td>
<td>Trainer, PA</td>
<td>185 (loss)</td>
<td>Idled since Sep 2011</td>
<td>Idled. Purchased by Delta Air Lines in April 2012, Delta Air Lines; transaction to close 1H 2012.</td>
</tr>
<tr>
<td>PBF Energy</td>
<td>Delaware City, DE</td>
<td>190</td>
<td>Oct 2011</td>
<td>PBF purchased the refinery in an idled state from Valero in June 2010 and restarted it in Oct 2011. The refinery had been idled since Nov 2009.</td>
</tr>
<tr>
<td>Sunoco</td>
<td>Marcus Hook, PA</td>
<td>175 (loss)</td>
<td>Idled since Dec 2011</td>
<td>Idled. For Sale with the intention to permanently close if no buyer by July 2012. Sunoco was purchased by Energy Transfer in April 2012 but under the agreement Sunoco will continue its plans to exit the refining business.</td>
</tr>
<tr>
<td>PBF Energy</td>
<td>Delaware City, DE</td>
<td>2014/2015</td>
<td>$1B project consisting of construction of a mild hydrocracker and hydrogen plant.</td>
<td></td>
</tr>
<tr>
<td>Sunoco</td>
<td>Philadelphia, PA</td>
<td>330 (potential loss)</td>
<td>Jul 2012</td>
<td>Operating but Sunoco announced that if no buyer found by July 2012, it would close.</td>
</tr>
</tbody>
</table>

### 3.2.2 PADD II (Midwest)

PADD II has a total refining capacity of 3.7 million b/d and in 2011, received almost 1.5 million b/d of foreign sourced crude oil, about 67 per cent of which were heavy crude oil volumes (Figure 3.6). Crude oil from western Canada totaled over 1.4 million b/d, making Canada the primary source of supplies. In 2011, most of the growth in western Canadian production was delivered to this market.

**Figure 3.6 2011 PADD II: Foreign Sourced Supply by Type and Domestic Crude Oil**

![Figure 3.6: 2011 PADD II: Foreign Sourced Supply by Type and Domestic Crude Oil](source: EIA)
PADD II can be further divided into the Northern, Eastern, and Southern PADD II states. The primary market hubs within PADD II are located at Clearbrook, Minnesota for the Northern PADD II states; Wood River-Patoka, Illinois area for the Eastern PADD II states; and Cushing, Oklahoma for the Southern PADD II states. The following subsections will discuss these markets in greater detail.

The Midwest region is currently Canada’s largest market due to its close proximity, large size and established pipeline network. However, this historically attractive market has become saturated as evidenced by the large buildup of inventories from growing domestic production and imports from western Canada. A number of refineries have announced projects designed to increase the heavy oil processing capability but there has been some delay in their startup due to the growing availability of light volumes from domestic production.

Northern PADD II

Northern PADD II consists of North Dakota, South Dakota, Minnesota and Wisconsin. There is one refinery in both North Dakota and Wisconsin and two refineries in Minnesota. These four refineries have a total refining capacity of 497,000 b/d. In 2011, foreign imports into northern PADD II were 295,700 b/d, all sourced from western Canada. Imports of western Canadian crude oil are expected to grow moderately to 342,300 b/d by 2020 (Figure 3.7). Growth in Canadian crude oil processed will be limited by the growing availability of crude oil from U.S. domestic production. Tesoro announced plans to expand crude capacity at its Mandan, North Dakota refinery to 68,000 b/d by the end of 2013 to handle increased crude oil volumes available from the U.S. Bakken play.

Eastern PADD II

Eastern PADD II consists of Michigan, Illinois, Indiana, Kentucky, Tennessee and Ohio and has 13 refineries with a total refining capacity of 2.5 million b/d. In 2011 western Canadian crude oil accounted for 1.1 million b/d or 93 per cent of the total foreign imports into the region.

There are several refining expansion projects that will be starting up in the next two years that are designed to process heavy crude oil sourced primarily from western Canada (Figure 3.8). Table 3.2 summarizes the recent and upcoming refinery upgrades announced for Eastern PADD II.

**Figure 3.7 PADD II (North): Forecast Western Canadian Crude Oil Receipts**

**Figure 3.8 PADD II (East): Forecast Western Canadian Crude Oil Receipts**
Southern PADD II

Southern PADD II has seven refineries, located in Kansas and Oklahoma that account for a combined refining capacity of 807,000 b/d. Cushing, Oklahoma is a hub that traditionally received crude oil predominately from pipelines transporting offshore crude oil delivered by tanker to the U.S. Gulf Coast. This crude oil is then distributed by a number of pipelines exiting the hub which serve refineries throughout the PADD II and PADD III regions. However, pipeline infrastructure has recently been constructed to transport growing western Canadian and U.S. Mid-continent crude oil volumes to the hub. These crude oil supplies are building up in storage in the region due to the lack of connectivity to markets, particularly those located on the Gulf Coast. A number of pipeline projects are expected to come into service that will remove some of these bottlenecks. The most recent project of note would be the reversed Seaway pipeline that started operating in May 2012 and increases takeaway capacity from Cushing and transports crude oil volumes to the Gulf Coast.

**Table 3.2 Summary of Major Announced Refinery Upgrades in Eastern PADD II**

<table>
<thead>
<tr>
<th>Operator</th>
<th>Location</th>
<th>Current Capacity (thousand b/d)</th>
<th>Scheduled In-Service</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>WRB Refining</td>
<td>Roxana, IL</td>
<td>306</td>
<td>2011</td>
<td>Add a 65,000 b/d coker; increase total crude oil refining capacity by 50,000 b/d; increase heavy oil refining capacity to 240,000 b/d.</td>
</tr>
<tr>
<td>BP</td>
<td>Whiting, IN</td>
<td>400</td>
<td>Late 2012 to mid 2013</td>
<td>Construction of 70,000 b/d new coker and a new crude distillation unit.</td>
</tr>
<tr>
<td>Marathon</td>
<td>Detroit, MI</td>
<td>102</td>
<td>Mid 2012</td>
<td>Increase heavy oil processing capacity by 80,000 b/d and increase total crude oil refining capacity to 115,000 b/d.</td>
</tr>
<tr>
<td>Husky</td>
<td>Lima, OH</td>
<td>160</td>
<td>1H 2013</td>
<td>Increase capacity to 170,000 b/d; 105,000 b/d would be heavy crude capacity. New 20,000 b/d kerosene hydrotreater.</td>
</tr>
</tbody>
</table>

**Figure 3.9 PADD II (South): Forecast Western Canadian Crude Oil Receipts**

Source: 2012 CAPP Refinery Survey
3.2.3 PADD III (Gulf Coast)

PADD III is comprised of Alabama, Arkansas, Louisiana, Mississippi, New Mexico and Texas. The refineries in this market have a total refining capacity of 9.1 million b/d, of which a significant portion has heavy crude oil processing capabilities.

In 2011, PADD III imported 4.9 million b/d of crude oil from foreign sources, of which 2.4 million b/d was heavy crude oil (Figure 3.10). The top five sources of these imports are as follows: Mexico (22 per cent), Saudi Arabia (17 per cent), Venezuela (16 per cent), Nigeria (9 per cent), and Columbia (6 per cent). Deliveries of western Canadian crude oil to this market totaled 112,000 b/d, almost all of which was transported through the ExxonMobil Pegasus pipeline. About 79 per cent of the heavy oil imports in the region are from Mexico, Venezuela and Columbia.

Mexico is the 7th largest crude oil producer in the world. However, the 2.96 million b/d of production in 2011 represented the seventh straight year of declining production. Mexico’s production from its once prolific Cantarell and Ku Maloob Zaap oil fields are undergoing steep declines. Mexico’s state-owned company, Pemex, is struggling to stabilize output from projects located in the deep waters of the Gulf of Mexico. Recent increases in Mexico’s own refining capacity has led to a decline in exports, most of which have traditionally gone to the United States. Mexico’s Minatitlan refinery’s processing capacity was expanded by 110,000 b/d in 2011.

Table 3.3 Summary of Major Announced Refinery Upgrades in PADD III

<table>
<thead>
<tr>
<th>Operator</th>
<th>Location</th>
<th>Current Capacity (thousand b/d)</th>
<th>Scheduled In-Service</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hunt Refining</td>
<td>Tuscaloosa, AL</td>
<td>72</td>
<td>Dec 2010</td>
<td>Increased capacity from 52,000 b/d to 72,000 b/d. Delayed coker was expanded to double in size to 32,000 b/d.</td>
</tr>
<tr>
<td>Total</td>
<td>Port Arthur, TX</td>
<td>232</td>
<td>Mar 2011</td>
<td>Increased capacity from 175,000 b/d to 232,000 b/d. Project included a 50,000 b/d coker; a 55,000 b/d vacuum distillation unit and a 64,000 b/d distillate hydrotreater.</td>
</tr>
<tr>
<td>Motiva Enterprises</td>
<td>Port Arthur, TX</td>
<td>285</td>
<td>2012</td>
<td>Addition of new single-train distillation unit with capacity of 325,000 b/d that would increase total capacity to over 600,000 b/d. New 95,000 b/d delayed coker; 85,000 b/d catalytic reformer, 75,000 b/d.</td>
</tr>
<tr>
<td>Valero</td>
<td>McKee, TX</td>
<td>170</td>
<td>2014</td>
<td>Increase capacity by 25,000 b/d. Expansion will process WTI and locally produced crude oil.</td>
</tr>
</tbody>
</table>

Total exports from Venezuela have also been declining due to both production declines and increased exports to China.

A number of pipeline projects will extend the reach of western Canadian producers into the Gulf Coast market in the next few years. By 2020, CAPP has estimated that this market could receive at least an additional 1.1 million b/d based on contractual commitments on the Keystone XL and Flanagan South pipelines.

Table 3.3 summarizes the recently completed major refinery upgrades and future upgrades announced for the region.
3.2.4 PADD IV (Rockies)

PADD IV includes the states of Idaho, Montana, Wyoming, Utah, and Colorado. It has 14 refineries spread out in every state except Idaho. PADD IV has a total refining capacity of 630,300 b/d with foreign imports being exclusively supplied from western Canada.

In 2011, PADD IV processed 234,200 b/d of Canadian crude oil representing about 43 per cent of its feedstock requirements. Throughout the forecast period, western Canadian crude oil receipts are forecast to remain relatively flat (Figure 3.11). The U.S. shale production is light oil and would not compete directly with the heavy crude oil imports available from western Canada. In January 2012, the Sinclair refinery in Sinclair, Wyoming was expanded from 60,000 b/d to 80,000 b/d. A coker unit and sulphur plants were added to the facility.

Figure 3.11 PADD IV: Forecast Western Canadian Crude Oil Receipts

![Figure 3.11 PADD IV: Forecast Western Canadian Crude Oil Receipts](image)

3.2.5 PADD V (West Coast)

PADD V includes the states of Alaska, Washington, Oregon, California, Nevada, Arizona and Hawaii. The majority of PADD V is geographically divided from the rest of the United States by the Rocky Mountains. It has very good access to tankers, and is located in close proximity to production from Alaska and California. Nonetheless, this market still depends on foreign imports for a large portion of its requirements (Figure 3.12).

For the purposes of the remainder of this report, the PADD V market region will focus only on Washington and California, as these states represent both the current demand and future prospects for western Canadian crude oil.

Figure 3.12 2011 PADD V: Foreign Sourced Supply by Type and Domestic Crude Oil

![Figure 3.12 2011 PADD V: Foreign Sourced Supply by Type and Domestic Crude Oil](image)
Washington

There are five refineries in Washington that have a combined capacity of 629,000 b/d. As production from Alaska, the primary source of feedstock, has been declining since 2002, Washington refineries are growing more dependent on foreign imports from Canada and other countries. In 2011, these refineries imported 245,800 b/d of crude oil from foreign sources. The top three sources were Canada (58 per cent), Russia (21 per cent), and Oman (7 per cent).

Tesoro is building capacity to receive 30,000 b/d of North Dakota crude oil by rail at its refinery located in Anacortes by September 2012. The company is also planning to apply for permits that would double the capacity to 60,000 b/d. In 2011, receipts of western Canadian crude oil were 147,600 b/d. Given the limited pipeline capacity available to the west coast, the use of rail could provide some additional access to this market in the near term. CAPP’s refinery survey of this market indicates a higher demand in 2017, which corresponds to the timing of the startup of announced pipeline projects to the west coast.

Figure 3.13 Washington: Forecast Western Canadian Crude Oil Receipts

California

California has 17 refineries with a total refining capacity of 2.1 million b/d. Most of the refineries are located near the coast in the Los Angeles area and in the San Francisco Bay area. These refineries account for almost 95 per cent of the refining capacity in the state. There is no direct pipeline to California from producing regions outside of California. Therefore, as Alaskan crude oil declines an opportunity arises to process more crude oil from Canada. Western Canadian crude oil would first have to be transported either on the Trans Mountain pipeline to the Westridge dock or by rail to the west coast where it would be loaded on to tankers. The Enbridge Gateway and Trans Mountain Pipeline Expansion projects represent an opportunity for greater future access to this market.

In 2011, California refineries imported 789,700 b/d of crude oil from foreign sources (Figure 3.14). The top three source countries were Saudi Arabia (29 per cent); Ecuador (22 per cent); and Iraq (16 per cent). Canada only accounted for 4 per cent of total foreign imports.

Figure 3.14 2011 PADD V (California): Foreign Sourced Supply by Type and Domestic Crude Oil

Total refining capacity = 2,102 thousand barrels per day

* Includes small volumes of Medium Sweet
Source: EIA and the California Energy Commission
3.3 Asia

Asia is the world’s fastest growing energy market and China and Japan are the second and 3rd largest oil markets in the world. World oil demand remains strong despite a slowdown in the U.S. and European economies because of increased demand in the Middle East and Asia. Japanese demand for crude oil as a source of power generation has also increased somewhat in order to make up for some of the lost nuclear generating capacity as a result of the Fukushima Daiichi nuclear disaster.

The outlook for China’s demand for heavy crude oil is improving, which is attributable to several modernizing projects in the last few years that have added new coking capacity. This has enabled Brazil to emerge as a growing supplier of medium heavy crude oil to this market without directly competing with the established Middle East producers, who are suppliers of light sour crude oil.

Canadian synthetic crude oil is suitable for Japanese refineries but would compete with sour grades imported from the Middle East. Table 3.4 shows oil demand from 2009 to 2012 in the major Asian markets. The International Energy Agency (IEA) forecasts that oil demand from China and India will grow in 2012 by 4 per cent and 3 per cent, respectively.

However, there is currently limited pipeline capacity available for the transportation of western Canadian crude oil to the west coast. The earliest that Canadian crude oil producers would be able to increase their market share in Asia is in 2017, if a new pipeline project to the west coast is approved.

<table>
<thead>
<tr>
<th>Table 3.4 Total Oil Demand in Major Asian Countries</th>
</tr>
</thead>
<tbody>
<tr>
<td>million b/d</td>
</tr>
<tr>
<td>China</td>
</tr>
<tr>
<td>India</td>
</tr>
<tr>
<td>Japan</td>
</tr>
<tr>
<td>Korea</td>
</tr>
</tbody>
</table>

Source: IEA Oil Market Report, May 2012

3.5 Markets Summary

The refineries on the U.S. Gulf Coast still represent an attractive market for Canadian crude oil supplies. Despite increasing U.S. domestic production, growing western Canadian crude oil supplies can still establish a larger market share in this region as pipeline infrastructure is developed. Foreign imports account for the majority of the feedstock requirement today but heavy crude oil from western Canada is well suited to displace a portion of the imports from Venezuela and Mexico. Based on the contractual commitments that have been obtained to underpin pipeline projects that would provide capacity to the Gulf Coast, western Canadian producers could supply at least 1.1 million b/d into this market by 2020. The demand for western Canadian crude oil in the U.S. Midwest is expected to rise by almost 470,000 b/d. The current flow of crude oil into this region far exceeds its ability to process it and there is insufficient takeaway capacity to move these growing supplies beyond the Cushing hub. Refineries in California and Washington are expected to import increasing volumes of foreign sourced crude given declining production from Alaska and western Canadian producers can compete for this market opportunity.

With growing North American supplies being forecast in conjunction with a flat outlook for crude oil demand in the U.S., producers are seeking to establish relationships with Asian refineries in order to diversify their export markets. China continues to emerge as a significant market, importing 5.7 million b/d of oil in 2011.

Figure 3.15 Net Oil Imports: Asia 2010 to 2030

Source: EIA 2012 Annual Energy Outlook, Early Release
Western Canadian crude oil is virtually landlocked and as such has very limited connectivity to world markets. Growing conventional, oil shale and oil sands production has created an urgent need for additional transportation infrastructure. Steps are being taken to address this need through a number of project proposals including new pipelines, expansions or modifications to existing infrastructure and increased transportation by rail. Pipelines will, however; continue to be the dominant mode of transportation for crude oil but it will take a few years for pipeline infrastructure to be built. In the short-term, crude oil transport by rail will increase sharply due to the ability to add rail capacity relatively quickly and in small increments as needed and utilizing the rail infrastructure already in place.

Figure 4.1 Canadian and U.S. Crude Oil Pipelines - All Proposals
Higher than expected production from Alberta and Saskatchewan conventional oil developments; the growth in North Dakota Bakken production, and new U.S. shale (Niobrara, Eagle Ford, etc.) production have added to the challenges to be resolved regarding the transportation of growing oil sands production.

Tight pipeline capacity as a result of these growing supplies has been one of the major reasons for the discounted prices received by Canadian and Mid-continent crude oil producers, whose production is priced off of WTI and not Brent, which is the global benchmark.

The existing pipeline network provides access to a number of markets for western Canadian crude oil including: western Canadian refineries; Ontario, the U.S. Midwest; PADD IV; and the West Coast. There is very limited access to the U.S. Gulf Coast. The major pipeline proposals currently being assessed are primarily expansions into the U.S. Gulf Coast and for exports off Canada’s west coast. Figure 4.1 shows all existing pipelines and active proposals.

4.1 Existing Crude Oil Pipelines Exiting Western Canada

There are four major pipelines that are directly connected to the Canadian supply hubs at Edmonton and Hardisty, Alberta: Enbridge Mainline, Kinder Morgan Trans Mountain Pipeline, Kinder Morgan Express Pipeline, and TransCanada Keystone Pipeline. Cumulatively, these pipelines provide a total annual average pipeline capacity out of western Canada of 3.5 million b/d. Proposals have been announced that would increase this capacity in 2014 and 2015 (Table 4.1). Existing capacity is currently constrained somewhat by the available takeaway capacity of connecting downstream pipelines. Capacity was further impacted in 2011 and early 2012 by short-term disruptions and pressure restrictions.

Enbridge Pipelines

The Enbridge Mainline is a multi-pipeline system that delivers crude oil and other refined products from western Canada, Montana and North Dakota to markets in western Canada, the U.S. Midwest and Ontario. It further extends its reach into additional markets through connections with a number of pipelines, namely the Minnesota Pipeline at Clearbrook, Minnesota and Spearhead South at Flanagan, Illinois. The receipt capacity of the Mainline system originating in western Canada is 2.3 million b/d.

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Crude Type</th>
<th>Annual Capacity (thousand b/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enbridge</td>
<td>Light</td>
<td>1,081</td>
</tr>
<tr>
<td></td>
<td>Heavy</td>
<td>1,246</td>
</tr>
<tr>
<td>AB Clipper</td>
<td>Heavy</td>
<td>+120 (in 2014)</td>
</tr>
<tr>
<td>Expansion</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Enbridge</td>
<td></td>
<td>+525 (in 2017)</td>
</tr>
<tr>
<td>Gateway</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Express</td>
<td>Light/heavy (35/65)</td>
<td>280</td>
</tr>
<tr>
<td>Trans Mountain</td>
<td>Light/heavy (80/20)</td>
<td>300</td>
</tr>
<tr>
<td>TM Expansion</td>
<td></td>
<td>+450 (in 2017)</td>
</tr>
<tr>
<td>Keystone</td>
<td>Light/heavy (25/75)</td>
<td>591</td>
</tr>
<tr>
<td>Keystone XL</td>
<td>Light/heavy</td>
<td>+830 (in 2015)</td>
</tr>
<tr>
<td>Total Existing Capacity</td>
<td></td>
<td>3,498</td>
</tr>
</tbody>
</table>

Crude oil production from Montana and North Dakota enters the Enbridge Mainline system through Enbridge’s North Dakota pipeline, which has a capacity of 210,000 b/d and is connected at Clearbrook, Minnesota. The Bakken Expansion project, which entails connecting production received at Berthold, North Dakota for delivery to the Enbridge Mainline at Cromer, Manitoba was approved by the NEB in December 2011. The incremental capacity of 145,000 b/d is expected to be in-service in 2013 and is designed to accommodate some of the escalating crude oil production from the Bakken play.

Enbridge Mainline Expansions - Alberta Clipper and Southern Access

The Alberta Clipper forms part of the Enbridge Mainline capacity exiting western Canada. It is a 36-inch pipeline extending from Hardisty, Alberta to Superior, Wisconsin with a capacity of 450,000 b/d that can be expanded to an ultimate capacity of 800,000 b/d with the addition of pumping stations. Enbridge has announced that it will be expanding the Alberta Clipper pipeline by 120,000 b/d in 2014.
The Southern Access Pipeline originates downstream of the Alberta Clipper at Superior, Wisconsin and runs to Flanagan, Illinois. It has a current capacity of 400,000 b/d, which can be expanded up to 1.2 million b/d. Enbridge has announced that it will expand the line by 160,000 b/d in 2014.

These Mainline expansions are required to support access to the U.S. Gulf Coast, ultimately through a connection to the Seaway Pipeline.

Kinder Morgan Trans Mountain Pipeline

The Trans Mountain system originates in Edmonton, Alberta and transports crude oil and petroleum products to delivery points in British Columbia. These delivery points include the Westridge dock for offshore exports to final destinations that include California, Asia and the U.S. Gulf Coast, as well as to a pipeline that provides deliveries to refineries in Washington State.

In December 2011, the NEB approved Kinder Morgan’s application to convert 54,000 b/d of common carrier capacity to firm service and change the land dock allocation on the system. Consequently, since February 2011, of the current pipeline capacity of 300,000 b/d (assuming 20 per cent of the volumes being transported are heavy crude oil), 221,000 b/d is allocated to refinery and terminal locations in British Columbia and Washington State and 79,000 b/d is allocated to Westridge dock shippers. The capacity designated to the dock is further divided between 54,000 b/d underpinned by firm contracts and the remainder available for spot shippers.

There was high apportionment on the pipeline throughout 2011; indicating strong demand by both land and dock shippers. The situation was magnified by pressure restrictions on the pipeline between April 2011 and March 2012. Strong demand for this pipeline space is expected to continue until there is additional capacity available to transport crude oil to the west coast for export. Two proposals currently exist. Refer to Section 4.5 for more details on oil pipelines to the West Coast. As an indication of high potential demand by offshore markets, a record volume of 143,000 b/d was delivered off the dock in April 2010.

Kinder Morgan Express-Platte Pipelines

The Express Pipeline system is a batch-mode, common carrier pipeline system comprised of the Express Pipeline and the Platte Pipeline that connects Canadian and U.S. crude oil producers to refineries in PADD IV and the U.S. Midwest. The Express Pipeline is a 24-inch diameter pipeline that originates at Hardisty, Alberta and terminates at the Casper, Wyoming facilities on the Platte Pipeline. Approximately 231,000 b/d out of the pipeline’s total capacity of 280,000 b/d has been secured by firm contracts from 2012 through to 2015.

The Platte Pipeline is a 20-inch diameter pipeline that runs from Casper, Wyoming to refineries and interconnecting pipelines in the Wood River, Illinois area. The Platte Pipeline has capacity of 150,000 b/d from Casper, Wyoming and approximately 140,000 b/d downstream of Guernsey, Wyoming.

Express currently has capacity on its system that can’t be used due to insufficient downstream capacity available on the Platte Pipeline. The Canadian portion of throughput exiting Guernsey in 2011 was 43 per cent versus 60 per cent in 2010.

TransCanada Keystone and Cushing Extension

The existing Keystone pipeline system runs from Hardisty, Alberta to terminals in Wood River and Patoka, Illinois and has been in operation since June 2010. The Keystone Cushing Extension, which runs from Steele City, Nebraska to Cushing, Oklahoma has been in-service since February 2011. The system can deliver a total capacity of 591,000 b/d, to either Wood River or Cushing depending on market requirements. Originally Keystone was underpinned by 375,000 b/d of contracted capacity while the Cushing Extension was underpinned by an additional 155,000 b/d of contracts.
**TransCanada Keystone XL**

On May 4, 2012, TransCanada filed a new Presidential Permit application for Keystone XL. This application will be supplemented later in 2012 with a revised routing in Nebraska once the Nebraska alternative route selection project is completed. If approved, TransCanada is planning for construction to start in the first quarter of 2013 with a targeted in-service date of late 2014 or early 2015. Keystone XL would originate at Hardisty, Alberta and end at Steele City, Nebraska. If the project is approved, its capacity of 830,000 b/d would contribute to the available pipeline capacity exiting western Canada.

TransCanada concluded a successful open season in October 2011 that secured contracts totaling 65,000 b/d of capacity for its Bakken Marketlink project from Baker, Montana, to Cushing. The project will enable receipts of up to 100,000 b/d of crude oil from the Williston Basin, primarily from the Bakken play, using capacity on the northern leg of Keystone XL. More than 500,000 b/d of capacity on Keystone XL has been contracted for an average term of 18 years.

**4.2 Oil Pipelines to the U.S. Midwest**

The U.S. Midwest is the largest market for western Canadian crude oil. The major market hubs in the U.S. Midwest where crude oil can be stored and transported to market are found at Wood River and Patoka in Illinois and at Cushing, Oklahoma. Table 4.2 summarizes the pipelines delivering Canadian-sourced crude oil to the Midwest.

**Minnesota Pipeline System**

The Minnesota Pipeline system is connected to the Enbridge system at Clearbrook, Minnesota, which enables it to deliver crude oil from Canada to the Northern Tier refinery located in St. Paul Park and the Flint Hills refinery in Rosemont. This is the primary route for Canadian crude oil destined for the Minnesota refineries. The system has a capacity of 465,000 b/d and can be further expanded by 185,000 b/d.

**Koch Wood River Pipeline**

The Minnesota refineries are connected to western Canadian crude oil supplies via connections to the Enbridge system as well as via deliveries from the Express system to Wood River where it then transits on the Koch Wood River System.

**Table 4.2 Summary of Crude Oil Pipelines to the U.S. Midwest**

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Originating Point</th>
<th>Destination</th>
<th>Status</th>
<th>Capacity (thousand b/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minnesota Pipeline</td>
<td>Clearbrook, MN</td>
<td>Minnesota refineries</td>
<td>Operating</td>
<td>465</td>
</tr>
<tr>
<td>Enbridge Mainline</td>
<td>Superior, WI</td>
<td>various delivery points via L5, L6, L14/64, Spearhead North</td>
<td>Operating</td>
<td>1,551</td>
</tr>
<tr>
<td>Enbridge Spearhead North Expansion</td>
<td>Flanagan, IL</td>
<td>Chicago, IL, Various delivery points via L5, L6, L14/64, Spearhead North</td>
<td>Proposed - 2014</td>
<td>+100</td>
</tr>
<tr>
<td>Enbridge Spearhead South</td>
<td>Flanagan, IL</td>
<td>Cushing, OK</td>
<td>Operating</td>
<td>193</td>
</tr>
<tr>
<td>Enbridge Flanagan South</td>
<td>Flanagan, IL</td>
<td>Cushing, OK</td>
<td>Proposed - 2014</td>
<td>+585</td>
</tr>
<tr>
<td>Enbridge Mustang</td>
<td>Lockport, IL</td>
<td>Patoka, IL</td>
<td>Operating</td>
<td>91</td>
</tr>
<tr>
<td>Kinder Morgan Express-Platte</td>
<td>Guernsey, WY</td>
<td>Wood River, IL</td>
<td>Operating</td>
<td>145</td>
</tr>
<tr>
<td>Trans Canada Keystone to Patoka or Wood River</td>
<td>Hardisty, AB</td>
<td>Patoka, IL</td>
<td>Operating</td>
<td>591*</td>
</tr>
<tr>
<td>Trans Canada Keystone to Cushing</td>
<td>Steele City, NE</td>
<td>Cushing, OK</td>
<td>Operating</td>
<td>591*</td>
</tr>
</tbody>
</table>

* Total capacity originating on the Keystone system to Patoka is up to 591,000 b/d less any volumes moved to the Cushing extension. Likewise, capacity for volumes delivered on Keystone to Cushing is up to 591,000 b/d less any volumes delivered to Patoka.
Spearhead Pipeline

The Spearhead Pipeline receives crude oil from the Enbridge Mainline and originates at Flanagan, Illinois. From there, crude oil can be transported to Griffith, Indiana via Spearhead North or to Cushing, Oklahoma on Spearhead South. Spearhead North currently has a capacity of 135,000 b/d, which Enbridge plans to expand to 235,000 b/d by 2014. The Spearhead South system has a capacity 193,000 b/d and will be expanded once its proposed twin pipeline, Flanagan South is built and begins operations.

Enbridge’s Toledo Pipeline Expansion

The Enbridge Toledo Pipeline connects to the Enbridge mainline at Stockbridge, Michigan and serves refineries at Toledo, Ohio and Detroit, Michigan. It is a 16-inch diameter pipeline with 100,000 b/d capacity. Enbridge is proposing to increase the capacity along this route by building a new 20-inch diameter pipeline that would have a capacity of 80,000 b/d. The new pipeline could be operating in early 2013.

4.3 Oil Pipelines to the U.S. Gulf Coast

The Gulf Coast is home to the largest refinery market in the world with refineries in the region being among the most complex in the world, enabling them to process a wide range of both light and heavy crude oil types. They are currently supplied by both U.S. domestic crude oil and foreign imports. A number of pipeline project proposals aim to serve this major market. Canadian crude, however, will be in competition with growing volumes of U.S. domestic supplies from the Mid-continent for space on these pipeline projects. Incidentally, there are several projects underway that propose to move U.S. production from new tight oil plays to the Gulf Coast and avoid the Cushing hub.

ExxonMobil Pegasus Pipeline

Before the reversed Seaway Pipeline came online on May 19, 2012, the ExxonMobil Pegasus Pipeline was the only pipeline that could deliver Canadian crude oil to the U.S. Gulf Coast. Pegasus is a 20-inch diameter pipeline with a capacity of 96,000 b/d that receives crude oil at Patoka, Illinois and delivers it to Nederland, Texas. Western Canadian crude oil, originating from Hardisty, Alberta transits to Pegasus from one of the following three originating routes

1) The Enbridge system followed by a connection on the Mustang Pipeline, which has a capacity of 100,000 b/d;

2) The Express/Platte system to Wood river, Illinois followed by a connection on the WOODPAT Pipeline, which has a capacity of 250,000 b/d; or

3) The Keystone Pipeline, which has a current capacity of 591,000 b/d.

Enbridge Flanagan South Pipeline

The Flanagan South Pipeline project is a 36-inch diameter pipeline that will be built parallel to the existing Enbridge Spearhead South Pipeline. The pipeline will originate at Flanagan, Illinois and terminate at Cushing, Oklahoma and will have an initial capacity of 585,000 b/d. The pipeline could be expanded to 800,000 b/d through the addition of pump capacity.

Table 4.3 Summary of Crude Oil Pipelines to the U.S. Gulf Coast

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Originating Point</th>
<th>Destination</th>
<th>Status</th>
<th>Capacity  (thousand b/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ExxonMobil Pegasus</td>
<td>Patoka, IL</td>
<td>Nederland, TX</td>
<td>Operating</td>
<td>96</td>
</tr>
<tr>
<td>Seaway Reversal Phase 1</td>
<td>Cushing, OK</td>
<td>Freeport, TX</td>
<td>Operating - May 2012</td>
<td>150</td>
</tr>
<tr>
<td>Seaway Reversal Phase 2</td>
<td>Cushing, OK</td>
<td></td>
<td>Proposed - Early 2013</td>
<td>+250</td>
</tr>
<tr>
<td>Seaway Twin Line</td>
<td>Cushing, OK</td>
<td></td>
<td>Proposed - Mid 2014</td>
<td>+450; expandable</td>
</tr>
<tr>
<td>TransCanada Gulf Coast</td>
<td>Cushing, OK</td>
<td>Nederland, TX</td>
<td>Proposed - Mid 2013</td>
<td>550; expandable</td>
</tr>
</tbody>
</table>
Enbridge/Enterprise Seaway Pipeline

The Seaway Pipeline is jointly owned by Enbridge Inc. and Enterprise Products Partners L.P. In 2011, Enbridge purchased a 50 per cent interest from ConocoPhillips. The pipeline was reversed in May 2012 and now moves crude oil from Cushing, Oklahoma to the U.S. Gulf Coast.

The first phase of the reversed 30-inch diameter Seaway Pipeline provides a capacity of 150,000 b/d. Following the completion of pump station additions and other modifications, which are expected to be completed in the first quarter of 2013, the capacity will increase to 400,000 b/d. In addition, Enbridge and Enterprise have held successful open seasons which resulted in five to 20 year contracts underpinning a new 30-inch diameter pipeline along the existing route of the Seaway pipeline. The initial capacity on this new Seaway Twinned pipeline would be 450,000 b/d, which could then be further expanded with the addition of incremental pump stations in the future. By mid-2014, these expansions would more than double the capacity of the Seaway system to 850,000 b/d from Cushing to the Gulf Coast.

Following successful open seasons, Enbridge secured 10, 15 and 20 year commitments. Western Canadian crude oil supplies could utilize this pipeline to connect to the reversed Seaway Pipeline at Cushing, Oklahoma to reach markets in the U.S. Gulf Coast. The target in-service date for this project is mid 2014.

TransCanada Gulf Coast Project and Houston Lateral

In an effort to address the urgent need for pipeline capacity to the U.S. Gulf Coast and in light of the U.S. Department of State’s denial of the TransCanada Keystone Pipeline, L.P. (TransCanada) Presidential Permit application for Keystone XL on January 18, 2012, TransCanada is developing the Gulf Coast segment of the project separately so that it may be in-service sooner. The 36-inch diameter, Gulf Coast Pipeline Project would originate at Cushing, Oklahoma and extend to Nederland, Texas. The Gulf Coast Pipeline project is anticipated to be in-service by mid to late 2013 with an initial capacity of 550,000 b/d that could ultimately ramp up to 830,000 b/d after Keystone XL begins operations.

The Houston Lateral Project is an additional project under development that is intended to extend the market reach of Keystone to refineries in Houston, Texas. The construction of this project is planned to begin in the first quarter of 2013 with the intent that the project would be operating by the first quarter of 2014. A number of options are also being explored to connect to refineries in Louisiana.

Once in-service, the Gulf Coast Pipeline and Houston Lateral projects will become integrated with the Keystone Pipeline System. Crude oil production from western Canada will enter the system through expanded facilities originating at Hardisty, Alberta to Steele City, Nebraska. The crude will subsequently be transported on to Cushing, Oklahoma.

4.4 Projects Dedicated to Divert U.S. Crude Oil from the Cushing Bottleneck

A number of projects are underway that propose to divert U.S. production of crude oil to the Gulf Coast and bypass the Cushing hub.

Shell’s Houma-to-Houston (Ho-Ho)

Shell Pipeline held a successful 45-day open season for its Ho-Ho Reversal project that ended April 20, 2012. The project entails reversing the existing Ho-Ho service in order to connect the Houston and Port Arthur markets in Texas with the Louisiana markets. This project could enable distribution of 300,000 b/d of crude oil across the region. Shell is proceeding with next steps and subject to regulatory approval, the Ho-Ho Reversal could begin service in early 2013.
Magellan Midstream’s Crane-to-Houston Pipeline

Magellan is proposing to reverse and convert a portion of its 18-inch Houston-to-El Paso pipeline (the former Longhorn pipeline) to crude oil service. Specifically, the project entails reversing the segment from Crane, Texas to Houston and converting it from refined petroleum products service to crude oil service. The objective is to transport crude oil produced in Texas producing regions (Permian Basin) to refineries in the Houston area. Subject to receiving the necessary regulatory approvals, the reversed 18-inch diameter pipeline would begin transporting crude oil at partial capacity by early 2013, ramping to its full 225,000 b/d capacity by mid-2013.

This project would provide a direct connection to the U.S. Gulf Coast and avoid the Cushing hub, potentially reducing the congestion there.

4.5 Oil Pipelines to the West Coast

The Kinder Morgan Trans Mountain Pipeline is currently the only pipeline route for western Canadian producers to transport crude oil to the west coast. Once there, the crude oil can be loaded off the dock to reach other markets such as California, the U.S. Gulf Coast and Asia. Forecasted growth in western Canadian production will quickly surpass the existing transportation capacity. New additional capacity to the west coast is key in order to link western Canadian crude oil production to the world market. Both Kinder Morgan and Enbridge have pipeline projects to increase access to the west coast. Table 4.4 summarizes the existing and proposed pipeline projects that could deliver western Canadian crude oil to the West Coast.

Table 4.4 Summary of Crude Oil Pipelines to the West Coast

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Originating Point</th>
<th>Destination</th>
<th>Status</th>
<th>Capacity (thousand b/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kinder Morgan Trans Mountain</td>
<td>Edmonton , AB</td>
<td>Burnaby, BC</td>
<td>Operating</td>
<td>300</td>
</tr>
<tr>
<td>Expansion</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Kinder Morgan Trans Mountain</td>
<td></td>
<td></td>
<td>Proposed - 2017</td>
<td>+450</td>
</tr>
<tr>
<td>Expansion</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Enbridge Northern Gateway</td>
<td>Bruderheim, AB</td>
<td>Kitimat, BC</td>
<td>Proposed - 2017</td>
<td>+525</td>
</tr>
</tbody>
</table>

Kinder Morgan Trans Mountain Expansion

The Trans Mountain Expansion project could increase capacity of the existing Trans Mountain system by 450,000 b/d, bringing the total capacity of the system from 300,000 to 750,000 b/d, at a projected cost of $4.1 billion. Through an open season process that ended in April 2012, shippers have signed 20-year term commitments totaling 510,000 b/d of capacity on the entire system. The expansion will twin the existing pipeline, where possible and also involves expansion of the Westridge Marine Terminal. Preceding a facilities application, Kinder Morgan intends to file a commercial tolling application in 2012 to review the company’s proposed tolling structure once the expansion is operational. Kinder Morgan’s facilities application with the National Energy Board is anticipated in 2014, and if approved, the proposed expansion is expected to be operational by 2017.

Enbridge Northern Gateway

The Northern Gateway Project includes the construction of a new 36-inch diameter pipeline that could transport 525,000 b/d of crude oil westward from Bruderheim, Alberta (near Edmonton, Alberta) to a deep water port at Kitimat, British Columbia. The pipeline could be expanded to an ultimate capacity of 850,000 b/d. Enbridge submitted an application to the National Energy Board at the end of May 2010. The ongoing hearing on the project is scheduled to conclude in April 2013. Subject to regulatory approval, startup of the pipeline is targeted for 2017.
4.6 Eastern Access

Refineries in Eastern Canada take some of their crude oil requirements from Newfoundland’s offshore wells, but most of the refinery feedstock is currently sourced internationally. There is significant interest in connecting western supplies to these markets.

Enbridge Line 9 Reversal

Enbridge Line 9 is a 30-inch diameter crude oil pipeline with a capacity of 240,000 b/d. Since 1999, the pipeline has been flowing crude oil westward from Montréal, Québec to Sarnia, Ontario, although originally the pipeline transported crude oil in a west to east direction when first placed in-service in 1975.

In August 2011, Enbridge filed an application with the National Energy Board (NEB) for the partial re-reversal of the line between Sarnia, Ontario and Westover, Ontario. The purpose of this reversal is to allow greater volumes of western Canadian crude oil to be delivered to the Imperial refinery at Nanticoke. The public hearing, conducted by the NEB to examine the application, was concluded in May 2012 and a decision is pending.

Further, Enbridge has announced a separate and distinct project for which it has secured sufficient commercial commitments to proceed with the reversal of Line 9 all the way to Montréal. An open season will be held from May 17 to June 15, 2012 to provide additional shippers with an opportunity to secure capacity on the pipeline. While subject to regulatory approval, the target in-service date for this project is in early 2014.

TransCanada East Coast Pipeline Project

TransCanada has introduced the concept of a new pipeline system to transport about 625,000 b/d of western Canadian crude oil across the country to Montréal, Québec and potentially further east to Saint John, New Brunswick. The project would involve converting about 3,000 km of under-utilized natural gas pipe into oil service; while building approximately 375 km of new pipe from Hardisty, Alberta to the Mainline at Burstall, Saskatchewan, and from Cornwall, Ontario, to Montréal. Another 220 km of pipe would be required to reach Québec City. Tankers could then take the crude oil to Europe or Asia. The proposal is only at the conceptual stage and has received very limited public discussion to date.

4.7 Diluent Pipelines

Table 4.5 summarizes the diluent pipeline proposals. These projects address the potential demand by western Canadian heavy crude oil producers for additional diluent supply needed to transport growing volumes of bitumen.

Table 4.5 Summary of Diluent Pipelines

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Originating Point</th>
<th>Destination</th>
<th>Status</th>
<th>Capacity (thousand b/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enbridge Southern Lights</td>
<td>Flanagan, IL</td>
<td>Edmonton, AB</td>
<td>Operating</td>
<td>180</td>
</tr>
<tr>
<td>Enbridge Northern Gateway</td>
<td>Kitimat, BC</td>
<td>Edmonton, AB</td>
<td>Proposed - 2017</td>
<td>193</td>
</tr>
<tr>
<td>Kinder Morgan Cochin</td>
<td>Kankakee County, IL</td>
<td>Fort Saskatchewan, AB</td>
<td>Open Season - ends May 2012</td>
<td>75</td>
</tr>
</tbody>
</table>
Enbridge Southern Lights

Since July 2010, the Southern Lights pipeline, which has a capacity of 180,000 b/d, has been transporting diluent from Flanagan, Illinois (near Chicago) to Edmonton, Alberta. In 2011, average throughput on the pipeline was around 60,000 b/d. Enbridge has announced an open season period ending June 22, 2012 to solicit interest for 85,000 b/d of firm contracted capacity on the pipeline. In its notice to FERC, Enbridge added that first rights to the additional capacity would be given to existing customers BP and Norway’s Statoil, who have already secured 77,000 b/d of capacity. The pipeline can be expanded to 330,000 b/d with minor looping and to over 400,000 b/d with full looping.

Enbridge Northern Gateway Diluent

As part of its Northern Gateway crude oil pipeline project, Enbridge is proposing a 193,000 b/d diluent import line that would extend from Kitimat, British Columbia to Edmonton, Alberta. The ongoing hearing on the project is scheduled to conclude in April 2013. Subject to regulatory approval, the target in-service date is 2017.

Kinder Morgan Cochin Reversal Project

Kinder Morgan is holding an open season to secure transportation contracts for its Cochin Reversal Project, which proposes to move condensate from Kankakee County, Illinois to existing terminal facilities near Fort Saskatchewan, Alberta. The project requires modifying and expanding the existing Cochin Pipeline to connect to the Explorer Pipeline in Kankakee County, then reversing the product flow to move condensate northwest to Canada. Subject to shipper support and regulatory approval, the pipeline would be in-service in July 2014. The existing Cochin pipeline system is a 12-inch diameter multi-product pipeline with the capacity to move 70,000 b/d. The Cochin Reversal project would be capable of delivering 75,000 b/d of light condensate.

4.8 An Alternative Mode of Transport: Rail

The rapid rise in U.S. Bakken crude oil production, the potential for further growth in tight oil production, as well as the long time lines required for the construction of new pipeline projects has led to an increased opportunity for rail as an alternative mode for transporting crude oil. In the span of just one year, rail exports from North Dakota have risen from about 50,000 b/d in March 2011 to about 225,000 b/d in March 2012, according to estimates by the North Dakota Pipeline Authority.

Transportation of crude oil production originating from western Canada by rail is also growing but is comparatively small – around 20,000 b/d in 2011. Rail is, however, starting to provide a larger proportion of the crude oil transportation market than it has held historically. According to Statistics Canada, about 8,823 rail cars (707,647 tonnes) were loaded in March 2012 transporting fuel oils and crude petroleum compared to 5,602 rail cars (458,696 tonnes) in March 2011. There is much discussion focused on using rail capacity to reach the various markets that are not currently well supplied by pipeline capacity.

Transporting crude by rail requires capital investment in new loading facilities that must also have corresponding unloading terminals at the destination centres. Rail car supply is currently tight and it takes about a year to put new rail cars into service. However, a major advantage to rail transport is the relatively quick startup for small additional volumes since an extensive rail network is already in place. Figure 4.2 is a map of the CP rail network and Figure 4.3 is a map of the CN rail network. A greater number of unloading terminals have been or are being built near destination markets.

Figure 4.2 CP Rail Network
The existing rail network has access to the Pacific, Atlantic and Gulf Coasts, and Eastern Canada. Test trains have been sent to California, Texas and Louisiana. Rail is being used to transport light crude and condensate. The rail industry has also proposed the option of utilizing heated rail cars to transport bitumen that could then be blended to specifications at terminals near the destination refineries.

Enbridge is proposing to enhance its North Dakota crude oil system by upgrading and expanding its current facilities located in Berthold, North Dakota to connect into a rail car loading facility south of its existing Berthold Station.

In mid 2011, G Seven Generations Ltd. unveiled a new strategy to transport crude oil from Fort McMurray, Alberta to the West Coast. Under the Unifying Nationals Railco Initiative, Alberta oil would travel by electric rail and would then be shipped to Asian markets from an existing marine terminal at Valdez, Alaska. Oil sands crude oil would be uploaded from rail cars at Delta Junction in Alaska, and then fed into an existing pipeline that terminates at Valdez.
4.9 Projects to Transport North Dakota Production

Production from North Dakota is sharply rising (producing a record 534,000 b/d in December 2011). Tesoro’s Mandan refinery in North Dakota is the closest market for Bakken crude but beyond this demand, producers must look for ways to transport production out of the state.

This production will compete for pipeline capacity out of western Canada. A number of projects have been proposed that would increase transportation out of this region, with the projects in turn seeking to connect downstream on the same facilities that transport Canadian crude oil production out of western Canada. The projects are summarized in Table 4.6.

Kinder Morgan Pony Express/True Companies Belle Fourche

Kinder Morgan’s Pony Express subsidiary and Belle Fourche Pipeline will hold an open season for 100,000 b/d of crude service from Baker, Montana, to Ponca City and Cushing, Oklahoma. The Open Season will close on June 20, 2012. Service under a joint tariff will begin in the fourth quarter of 2014. The pipeline is anchored with a 30,000 b/d long-term commitment from a major anchor shipper.

The project will combine True Companies’ Belle Fourche system, which runs from Baker to Guernsey, Wyoming, with Kinder Morgan’s 210,000 b/d Pony Express line, which involves the conversion of a natural gas pipeline to crude oil service from Guernsey to Cushing.
4.10 Pipeline Summary

The dynamics of the North American crude oil market are changing as growing western Canadian and Mid-continent crude oil production emerges while North American crude oil consumption is anticipated to be fairly flat. Despite the forecast for flat demand for crude oil, the U.S., specifically the Gulf Coast, remains a large, attractive market for western Canadian producers due to the opportunity to displace crude oil supplies from international sources. A number of pipeline proposals to the Gulf Coast have recently been announced that will increase access by 2014 through connections to existing infrastructure as well as new projects. In addition to looking for increased penetration to U.S. markets, western Canadian crude oil producers are also seeking much greater market diversification through increased connectivity to world markets. This would primarily be achieved through more pipeline capacity to the west coast, where crude oil could be shipped to the burgeoning economies of Asia. There is also significant interest in improving connectivity to western Canadian supplies for all Canadians. As such, a number of projects to increase pipeline access from western Canada to eastern Canadian markets are being pursued.

Projects that increase the downstream capacity of existing pipelines have been proposed that could partially alleviate tight capacity as access to markets is enhanced. However, additional capacity exiting western Canada will need to be built if growing production is to avoid facing chronic apportionment as a result of limited pipeline capacity to desired markets. Figure 4.4 shows the existing and proposed takeaway capacity exiting the WCSB versus forecasted supply. The forecasted supply volume was developed by coupling CAPP’s latest supply forecast of Western Canadian production with U.S. Bakken volumes that could utilize a portion of the capacity that exits western Canada.

Transportation of crude oil by rail is growing since it has the advantage of quick start-up and its network extends to a number of markets that are currently not connected through the pipeline network. However, pipelines will remain the preferred mode of transportation for crude oil. This analysis indicates that additional pipeline capacity exiting western Canada will be required by 2014.
## GLOSSARY

<table>
<thead>
<tr>
<th>Term</th>
<th>Description</th>
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<tbody>
<tr>
<td>API Gravity</td>
<td>A specific gravity scale developed by the American Petroleum Institute (API) for measuring the relative density or viscosity of various petroleum liquids.</td>
</tr>
<tr>
<td>Barrel</td>
<td>A standard oil barrel is approximately equal to 35 Imperial gallons (42 U.S. gallons) or approximately 159 litres.</td>
</tr>
<tr>
<td>Bitumen</td>
<td>A heavy, viscous oil that must be processed extensively to convert it into a crude oil before it can be used by refineries to produce gasoline and other petroleum products.</td>
</tr>
<tr>
<td>Coker</td>
<td>The processing unit in which bitumen is cracked into lighter fractions and withdrawn to start the conversion of bitumen into upgraded crude oil.</td>
</tr>
<tr>
<td>Condensate</td>
<td>A mixture of mainly pentanes and heavier hydrocarbons. It may be gaseous in its reservoir state but is liquid at the conditions under which its volumes is measured or estimated.</td>
</tr>
<tr>
<td>Crude oil (Conventional)</td>
<td>A mixture of pentanes and heavier hydrocarbons that is recovered or is recoverable at a well from an underground reservoir. It is liquid at the conditions under which its volumes is measured or estimated and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas, condensate, or bitumen.</td>
</tr>
<tr>
<td>Crude oil (heavy)</td>
<td>Crude oil is deemed, in this report, to be heavy crude oil if it has an API of 27º or less. No differentiation is made between sweet and sour crude oil that falls in the heavy category because heavy crude oil is generally sour.</td>
</tr>
<tr>
<td>Crude oil (medium)</td>
<td>Crude oil is deemed, in this report, to be medium crude oil if it has an API greater than 27º but less than 30º. No differentiation is made between sweet and sour crude oil that falls in the medium category because medium crude oil is generally sour.</td>
</tr>
<tr>
<td>Crude oil (synthetic)</td>
<td>A mixture of hydrocarbons, similar to crude oil, derived by upgrading bitumen from the oil sands.</td>
</tr>
<tr>
<td>Density</td>
<td>The mass of matter per unit volume.</td>
</tr>
<tr>
<td>DilBit</td>
<td>Bitumen that has been reduced in viscosity through addition of a diluent (or solvent) such as condensate or naphtha.</td>
</tr>
<tr>
<td>Diluent</td>
<td>Lighter viscosity petroleum products that are used to dilute bitumen for transportation in pipelines.</td>
</tr>
<tr>
<td>Extraction</td>
<td>A process unique to the oil sands industry, in which bitumen is separated from their source (oil sands).</td>
</tr>
<tr>
<td>Feedstock</td>
<td>In this report, feedstock refers to the raw material supplied to a refinery or oil sands upgrader.</td>
</tr>
<tr>
<td>Integrated mining project</td>
<td>A combined mining and upgrading operation where oil sands are mined from open pits. The bitumen is then separated from the sand and upgraded by a refining process.</td>
</tr>
<tr>
<td>In Situ recovery</td>
<td>The process of recovering crude bitumen from oil sands by drilling.</td>
</tr>
<tr>
<td>Merchant upgrader</td>
<td>Processing facilities that are not linked to any specific extraction project but is designed to accept raw bitumen on a contract basis from producers.</td>
</tr>
</tbody>
</table>
**Oil**
Condensate, crude oil, or a constituent of raw gas, condensate, or crude oil that is recovered in processing and is liquid at the conditions under which its volume is measured or estimated.

**Oil sands**
Refers to a mixture of sand and other rock materials containing crude bitumen or the crude bitumen contained in those sands.

**Oil Sands Deposit**
A natural reservoir containing or appearing to contain an accumulation of oil sands separated or appearing to be separated from any other such accumulation. The ERCB has designated three areas in Alberta as oil sands areas.

**Oil Sands Heavy**
In this report, Oil Sands Heavy includes upgraded heavy sour crude oil, and bitumen to which light oil fractions (i.e. diluent or upgraded crude oil) have been added in order to reduce its viscosity and density to meet pipeline specifications.

**Pentanes Plus**
A mixture mainly of pentanes and heavier hydrocarbons that ordinarily may contain some butanes and is obtained from the processing of raw gas, condensate or crude oil.

**PADD**
Petroleum Administration for Defense District that defines a market area for crude oil in the U.S.

**Refined Petroleum Products**
End products in the refining process (e.g. gasoline).

**Specification**
Defined properties of a crude oil or refined petroleum product.

**SynBit**
A blend of bitumen and synthetic crude oil that has similar properties to medium sour crude oil.

**Upgrading**
The process that converts bitumen or heavy crude oil into a product with a lower density and viscosity.

**West Texas Intermediate**
WTI is a light sweet crude oil, produced in the United States, which is the benchmark grade of crude oil for North American price quotations.
APPENDIX A
ACRONYMS, ABBREVIATIONS,
UNITS AND CONVERSION FACTORS

Acronyms

API       American Petroleum Institute
CAPP      Canadian Association of Petroleum Producers
EIA       Energy Information Administration
ERCB      (Alberta) Energy Resources Conservation Board
FERC      Federal Energy Regulatory Commission
IEA       International Energy Agency
NEB       National Energy Board
PADD      Petroleum Administration for Defense District
U.S.      United States
WCSB      Western Canada Sedimentary Basin
WTI       West Texas Intermediate

Canadian Provincial Abbreviations

AB        Alberta
BC        British Columbia
MB        Manitoba
NWT       Northwest Territories
ON        Ontario
QC        Québec
SK        Saskatchewan

Units

b/d       barrels per day

Conversion Factor

1 cubic metre = 6.293 barrels (oil)
## U.S. State Abbreviations

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<td>WY</td>
<td>Wyoming</td>
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# APPENDIX B.1

## CAPP Canadian Crude Oil Production Forecast 2012 – 2030

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<thead>
<tr>
<th>thousand barrels per day</th>
<th>Actuals</th>
<th>Forecast</th>
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<tr>
<td><strong>CONVENTIONAL</strong></td>
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<tr>
<td>Light &amp; Medium</td>
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<tr>
<td>Alberta</td>
<td>319</td>
<td>350</td>
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<tr>
<td>B.C.</td>
<td>22</td>
<td>20</td>
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<tr>
<td>Saskatchewan 1,2</td>
<td>186</td>
<td>188</td>
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<td>Manitoba</td>
<td>32</td>
<td>40</td>
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<td>Ontario</td>
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<td>1</td>
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<tr>
<td>Newfoundland &amp; Labrador</td>
<td>276</td>
<td>267</td>
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<tr>
<td>Total Conv. Light &amp; Medium</td>
<td>1,226</td>
<td>1,259</td>
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<tr>
<td><strong>TOTAL CONVENTIONAL</strong></td>
<td>1,470</td>
<td>1,615</td>
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<td>PENTANES/CONDENSATE</td>
<td>144</td>
<td>142</td>
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<td><strong>OIL SANDS (BITUMEN &amp; UPGRADED CRUDE OIL)</strong></td>
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<td>Oil Sands Mining</td>
<td>727</td>
<td>772</td>
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<td>Oil Sands In Situ</td>
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<td>844</td>
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<tr>
<td>Total Oil Sands</td>
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<td>1,615</td>
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<td><strong>WESTERN CANADA OIL PRODUCTION</strong></td>
<td>2,556</td>
<td>2,743</td>
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<td><strong>EASTERN CANADA OIL PRODUCTION</strong></td>
<td>284</td>
<td>273</td>
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<td><strong>TOTAL CANADIAN OIL PRODUCTION</strong></td>
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<td>Oil Sands Raw Bitumen**</td>
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<td>Oil Sands In Situ</td>
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<td>Total Oil Sands</td>
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<td>1,745</td>
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### APPENDIX B.2  2012 – 2030 Western Canadian Crude Oil Supply

**Blended Supply to Trunk Pipelines and Markets**  
*thousand barrels per day*

<table>
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<tr>
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<tr>
<td>Total Light and Medium</td>
<td>570</td>
<td>702</td>
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<tr>
<td>Net Conventional Heavy to Market</td>
<td>309</td>
<td>323</td>
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<tr>
<td><strong>TOTAL CONVENTIONAL</strong></td>
<td>879</td>
<td>1,025</td>
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</table>

| **OIL SANDS**          |         |          |
| Upgraded Light (Synthetic) | 660 | 804    |
| Oil Sands Heavy         | 1,134   | 1,310   |
| **TOTAL OIL SANDS AND UPGRADEERS** | 1,794 | 2,115   |

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<tr>
<td>Total Light Supply</td>
<td>1,229</td>
<td>1,311</td>
<td>1,506</td>
<td>1,665</td>
<td>1,736</td>
<td>1,797</td>
<td>1,839</td>
<td>1,809</td>
<td>1,852</td>
<td>1,909</td>
<td>1,948</td>
<td>1,954</td>
<td>1,931</td>
<td>1,924</td>
<td>1,945</td>
<td>1,920</td>
<td>1,862</td>
<td>1,828</td>
<td>1,802</td>
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<tr>
<td>Total Heavy Supply</td>
<td>1,444</td>
<td>1,608</td>
<td>1,633</td>
<td>1,803</td>
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<td>2,092</td>
<td>2,287</td>
<td>2,486</td>
<td>2,611</td>
<td>2,801</td>
<td>3,037</td>
<td>3,229</td>
<td>3,470</td>
<td>3,675</td>
<td>3,947</td>
<td>4,233</td>
<td>4,325</td>
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**WESTERN CANADA OIL SUPPLY**  
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<tbody>
<tr>
<td>Total Light</td>
<td>2,673</td>
<td>2,918</td>
<td>3,139</td>
<td>3,468</td>
<td>3,705</td>
<td>3,890</td>
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<td>4,295</td>
<td>4,420</td>
<td>4,653</td>
<td>4,946</td>
<td>5,177</td>
<td>5,424</td>
<td>5,606</td>
<td>5,871</td>
<td>6,179</td>
<td>6,244</td>
<td>6,418</td>
<td>6,585</td>
<td>6,695</td>
<td>6,870</td>
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**Notes:**

1. CAPP allocates Saskatchewan Area III Medium crude as heavy crude. Also 17% of Area IV is > 900 kg/m³.
2. CAPP has revised from the June 2007 report historical light/heavy ratio for Saskatchewan starting in 2005.
3. Raw bitumen numbers are highlighted. The oil sands production numbers (as historically published) are a combination of upgraded crude oil and bitumen and therefore incorporate yield losses from integrated upgrader projects. Production from off-site upgrading projects are included in the production numbers as bitumen.
4. Includes upgraded conventional.
5. Includes: a) imported condensate b) manufactured diluent from upgraders and c) upgraded heavy volumes coming from upgraders.
APPENDIX C

Crude Oil Pipelines and Refineries

Vancouver to:
- Japan - 4,300 miles
- Taiwan - 5,600 miles
- S.Korea - 4,600 miles
- China - 5,100 miles
- San Francisco - 800 miles
- Los Angeles - 1,100 miles

San Francisco - 800 miles
Los Angeles - 1,100 miles
2011 Canadian Crude Oil Production

<table>
<thead>
<tr>
<th>Province</th>
<th>000 m³/d</th>
<th>000 b/d</th>
</tr>
</thead>
<tbody>
<tr>
<td>British Columbia</td>
<td>6</td>
<td>37</td>
</tr>
<tr>
<td>Alberta</td>
<td>354</td>
<td>2,225</td>
</tr>
<tr>
<td>Saskatchewan</td>
<td>69</td>
<td>431</td>
</tr>
<tr>
<td>Manitoba</td>
<td>6</td>
<td>40</td>
</tr>
<tr>
<td>Northwest Territories</td>
<td>2</td>
<td>10</td>
</tr>
<tr>
<td>Western Canada</td>
<td>436</td>
<td>2,741</td>
</tr>
<tr>
<td>Eastern Canada</td>
<td>43</td>
<td>273</td>
</tr>
<tr>
<td>Total Canada</td>
<td>479</td>
<td>3,017</td>
</tr>
</tbody>
</table>

Pipeline Tolls Light Oil (US$ per barrel)

- Edmonton to Burnaby (Trans Mountain): 2.70
- Anacortes (Trans Mountain/Puget): 2.90
- Sarnia (Enbridge): 3.95
- Chicago (Enbridge): 3.55
- Wood River (Enbridge/Mustang/Capwood): 4.60
- USGC (Enbridge/Mustang/ExxonMobil): 6.15
- USGC (Enbridge/Spearhead/Seaway): 7.05*
- Hardisty to Guernsey (Express/Platte): 1.55*
- Wood River (Express/Platte): 1.90*
- Wood River (Keystone): 4.70**
- Wood River (Enbridge/Mustang/Capwood): 5.45
- Wood River (Keystone): 5.35**
- Wood River (Express/Platte): 2.30*
- USGC (Express/Platte/MAP/ExxonMobil): 3.75
- USEC to Sarnia (Portland/Montreal/Enbridge): 4.40
- St. James to Wood River (Capline/Capwood): 1.05

Pipeline Tolls -Heavy Oil (US$ per barrel)

- Hardisty to: Chicago (Enbridge): 4.00
- Cushing (Enbridge/Spearhead): 5.00
- Cushing (Keystone): 6.15**
- Cushing (Keystone): 6.55*
- Wood River (Enbridge/Mustang/Capwood): 5.45
- Wood River (Keystone): 5.35**
- Wood River (Express/Platte): 2.30*
- USGC (Enbridge/Spearhead/Seaway): 8.00*

Notes:
1) Assumed exchange rate = 1US$ / 1C$
2) Tolls rounded to nearest 5 cents
3) Tolls in effect July 1, 2012

*10-year committed toll
**20-year committed toll

Maps of major existing crude oil pipelines and selected other crude oil pipelines are shown.
The Canadian Association of Petroleum Producers (CAPP) represents companies, large and small, that explore for, develop and produce natural gas and crude oil throughout Canada. CAPP’s member companies produce more than 90 per cent of Canada’s natural gas and crude oil. CAPP’s associate members provide a wide range of services that support the upstream crude oil and natural gas industry. Together CAPP’s members and associate members are an important part of a national industry with revenues of about $100 billion-a-year.

CAPP’s mission is to enhance the economic sustainability of the Canadian upstream petroleum industry in a safe and environmentally and socially responsible manner, through constructive engagement and communication with governments, the public and stakeholders in the communities in which we operate.

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