CANADIAN ASSOCIATION
OF PETROLEUM PRODUCERS

Crude Oil

Forecast, Markets & Transportation

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On Cover:
Cenovus *in situ* project
BP Whiting refinery - courtesy of BP: photo by Marc Morrison

EXECUTIVE SUMMARY

CAPP annually publishes its long-term outlook for Canadian crude oil production to provide a basis on which to build a common understanding among stakeholders, including industry, governments, and the general public regarding the growth in Canadian oil supply and the need for additional market access.

The key points of this year's outlook are:

- Canadian oil production continues to grow and although oil sands remains the largest component of growth, the resurgence of conventional crude oil production represents the largest year over year change to the previous forecast. This resurgence in conventional tight oil is occuring both in Canada and the U.S., enabling greater continental energy security and changing the historical flows throughout North America.
- The main market opportunities occur in the replacement of offshore foreign crude imports in Canada and the United States and in the potential for exports beyond North America.
- Transportation capacity is currently tight and in addition to new pipeline options coming forward, rail has quickly become another way to move oil to market.

Crude Oil Production and Supply

Canadian crude oil production is expected to grow steadily to 2030. Oil sands production reaches 5.2 million b/d by the end of the outlook. Declining eastern Canada production is offset by growth in conventional production from western Canada, so combined production stabilizes at a level of almost 1.5 million b/d. Compared to last year's forecast, conventional production is higher by 300,000 b/d while oil sands production is up by 200,000 b/d by 2030.

Conventional Oil

The application of advanced drilling technology to previously inaccessible tight oil reserves has reversed the steady decline seen in conventional production over the last several decades. Currently conventional production in western Canada is 1.2 million b/d and is expected to grow to 1.4 million b/d by 2015. Light, tight crude oil production is expected to account for most of this growth.

Canadian Crude Oil Production

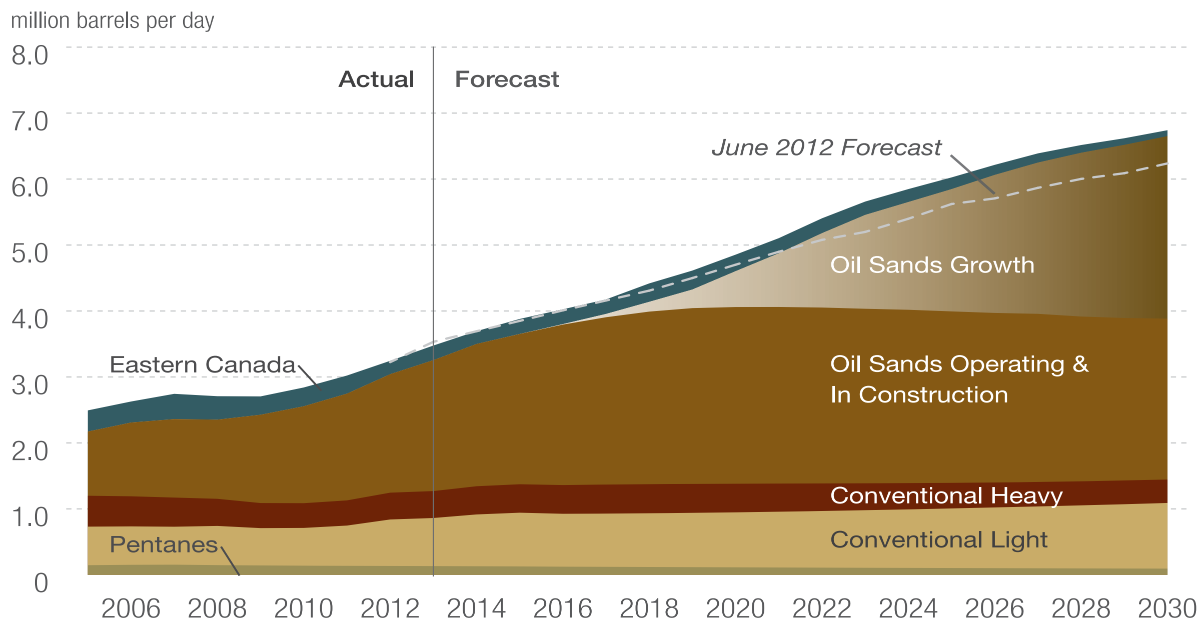
million b/d	2012	2015	2020	2025	2030
Total* Canadian (including oil sands)	3.2	3.9	4.9	6.0	6.7
Eastern Canada	0.2	0.2	0.2	0.2	0.1
Western Canada					
Conventional (including condensate)	1.2	1.4	1.4	1.4	1.4
Oil sands	1.8	2.3	3.2	4.5	5.2

*Totals may not add up due to rounding.

Oil Sands

The oil sands represent the vast majority of Canada's crude oil reserves, so naturally this resource will be the primary driver for future overall growth. The 2013 outlook for oil sands is similar in aggregate to last year's forecast but with a higher growth outlook for *in situ* production that offsets a lower growth outlook for mining production.

Canadian Oil Sands & Conventional Production



In 2012, 1.8 million b/d were produced from the oil sands of which 800,000 b/d was from mining and 1.0 million b/d were recovered by *in situ* techniques. Looking ahead to 2030, mining production is forecast to increase to 1.7 million b/d and *in situ* production is forecast to grow to 3.5 million b/d.

Eastern Canada

Eastern Canada produced about 6 per cent, or 202,000 b/d of total Canadian crude oil production. Hebron, the fourth major offshore project, is expected to begin production by the end of 2017 and will help offset declines from mature existing projects.

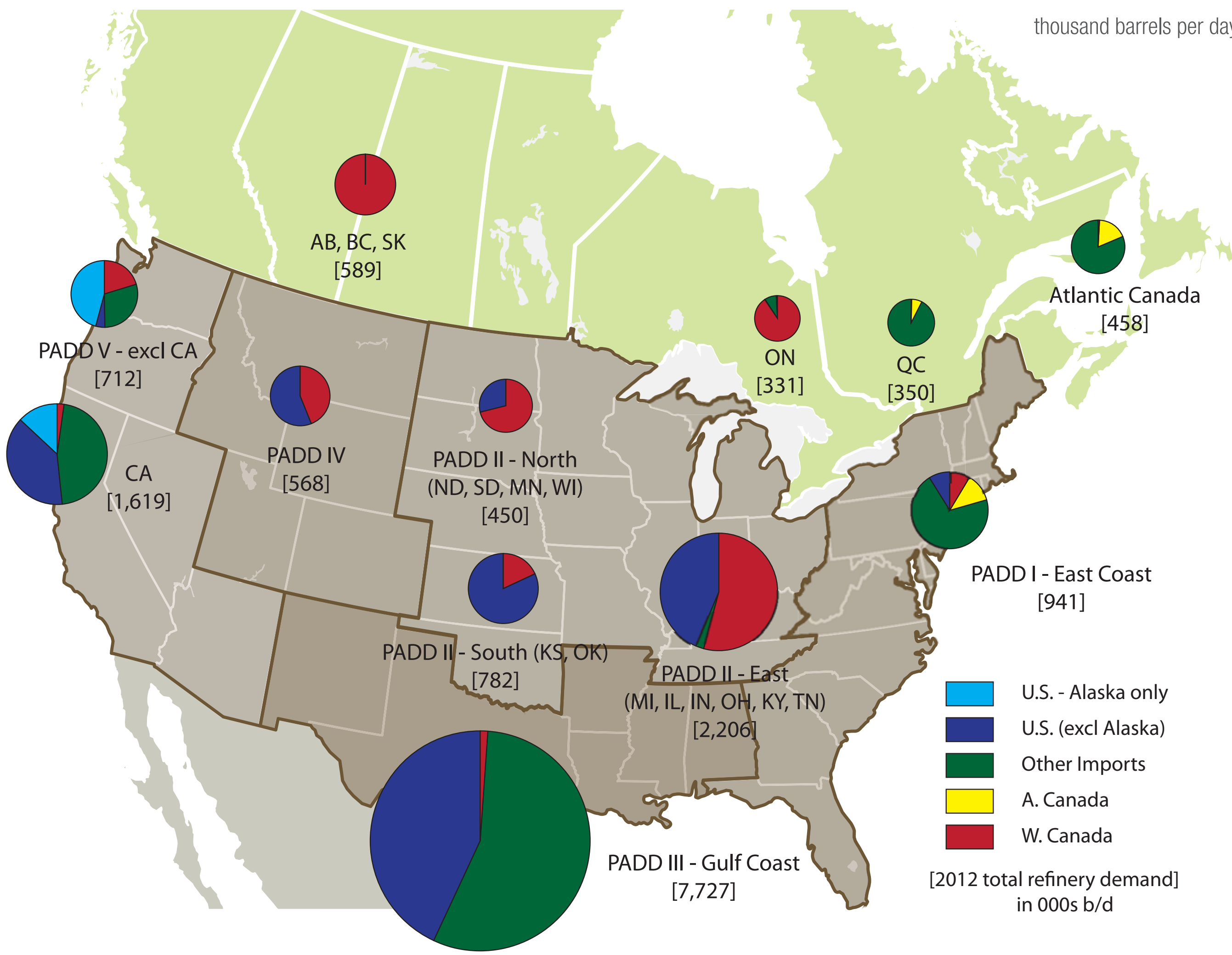
Crude Oil Markets

Given the growing production outlook, the need to reach new markets is a top priority for Canadian oil producers. A fundamental shift is occurring in the market due to strong growth in light crude oil production, which is replacing offshore imports to the light oil refineries in eastern Canada and the United States. Markets for growing heavy oil supplies are primarily found in the U.S. Midwest and Gulf Coast. New market opportunities are also emerging as a result of growing demand in Asia.

Eastern Canada

Refineries in Québec and Atlantic Canada currently import 86 per cent of their requirements. This means there is a potential 700,000 b/d domestic market for growing Canadian oil supplies. Refineries in Ontario have already shifted their main source of supply and obtain more than 90 per cent of their crude oil feedstock from Canadian supplies.

2012 Canada and U.S. Crude Oil Demand by Market Region



Sources: CAPP, CA Energy Commission, EIA, Statistics Canada

United States

Crude oil demand by U.S. Gulf Coast refineries in 2012 was almost 8 million b/d. Most of these refineries have the capacity to process heavy crude oil that has traditionally been imported primarily from Venezuela and Mexico. Over 2.2 million b/d of heavy crude oil imports were processed in 2012. Canadian producers could displace some of these imported volumes and is forecast to supply at least 1.1 million b/d to this market by 2020 up from the 100,000 b/d that is currently supplied.

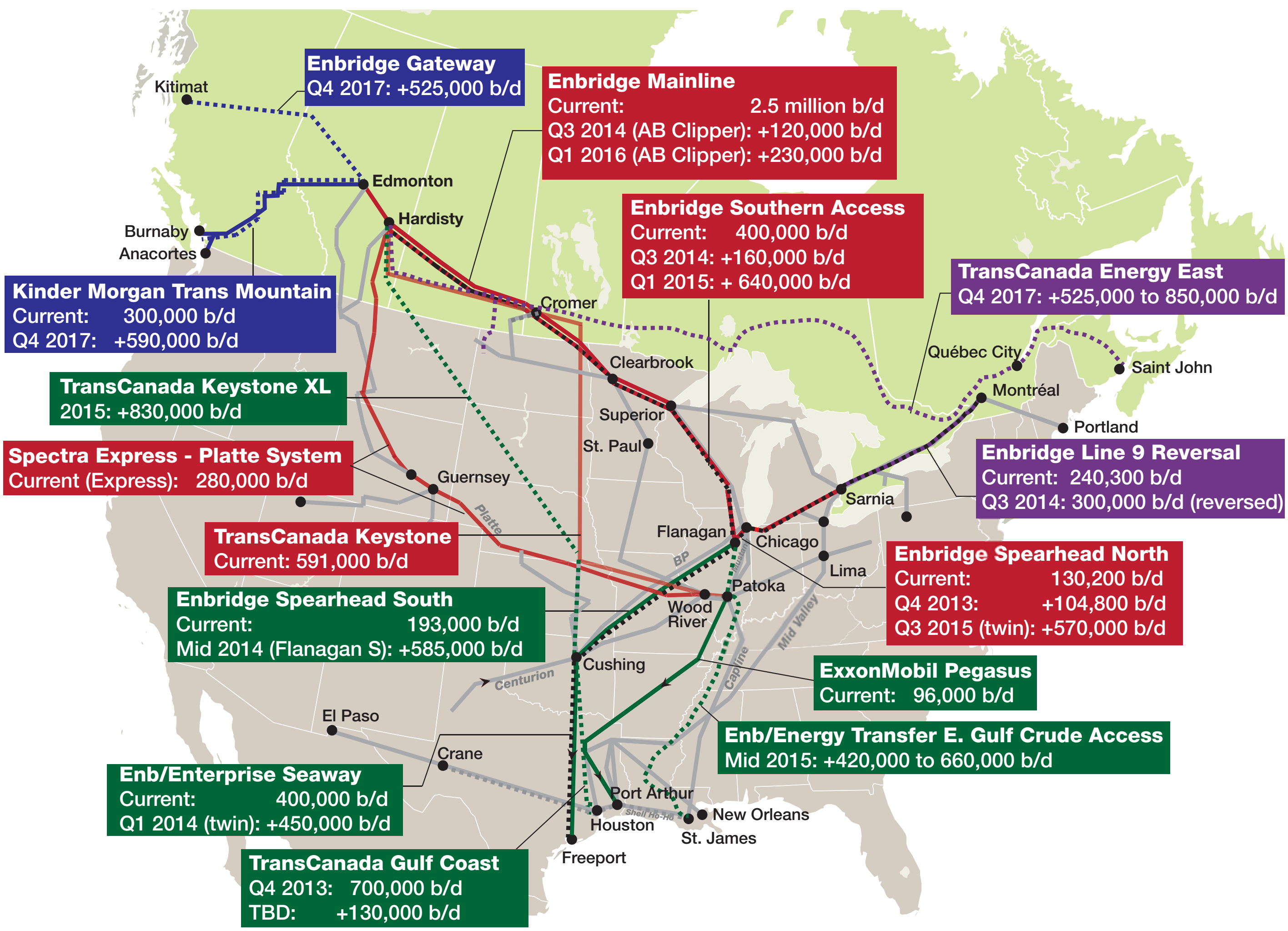
In 2012, Canada supplied 1.7 million b/d to the Midwest, making it Canada's largest export market. A number of refinery conversion projects for processing heavy crude oil have recently been completed and are anticipated to increase demand in the region by 460,000 b/d by 2020.

Refineries in Washington and California need to replace their traditional sources of supply that are now declining and may represent a future market opportunity for Canadian producers.

Asia

Asia is a region of strong growth in energy demand to which Canada currently has very limited access. China and India in particular are obvious markets as they currently have the fastest growing economies in the world. According to the U.S. Energy Information Administration (EIA), their combined oil imports are forecast to increase by 6 million b/d; going from 9.2 million b/d in 2012 to 15.7 million b/d by 2030.

Canadian & U.S. Crude Oil Pipelines and Proposals



Crude Oil Transportation

Transportation capacity is currently tight, however, there have been no reports of this resulting in production being shut-in. This outlook assumes transportation capacity can grow to accommodate the projected increase in supply.

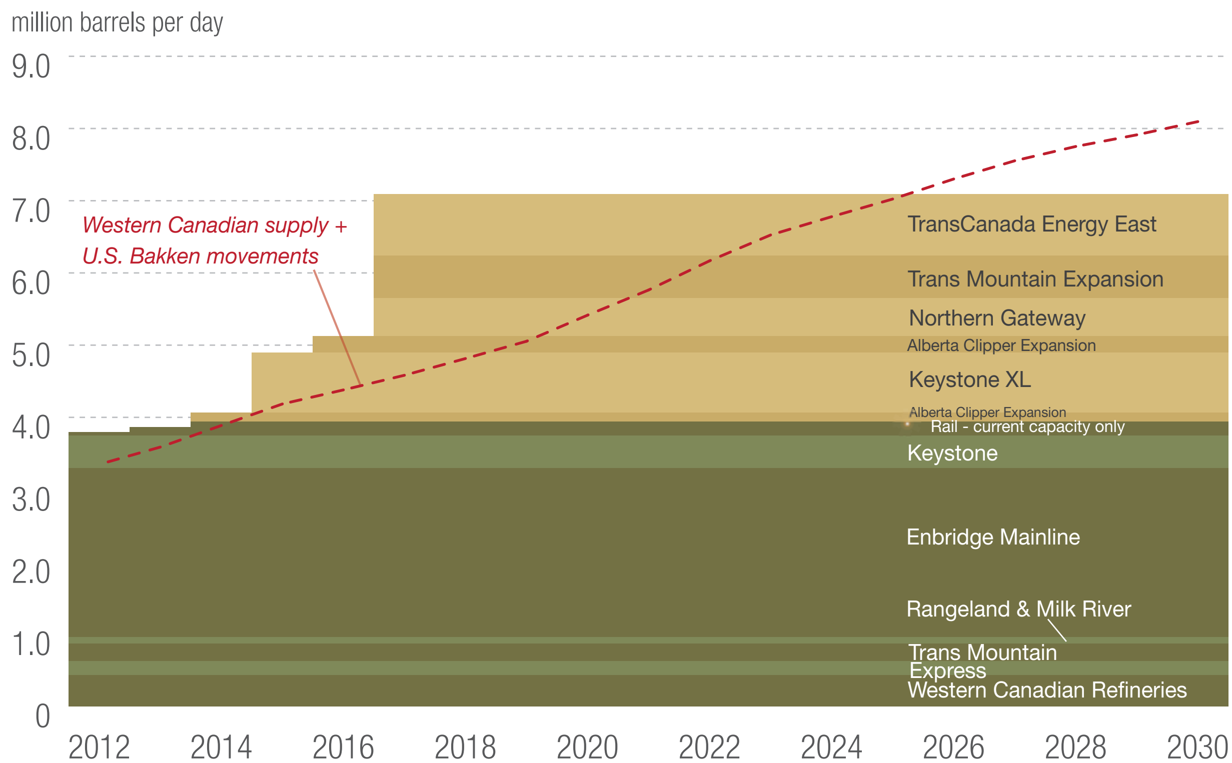
Western Canadian supplies are essentially landlocked and will need additional transportation infrastructure to bring this growing oil supply to markets. Protracted approval processes for new pipeline projects are resulting in a variety of creative transportation proposals to access markets.

It is clear that based on the pipeline projects being proposed (see figure on previous page), industry continues to broaden the scope of markets that it wants to access. Transportation projects involve both the expansion and conversion of existing infrastructure as well as the development of new infrastructure to diversify market access for Canadian producers.

Rail is a growing transportation option for moving crude oil to markets, which is being enabled by construction of new loading facilities and the manufacturing of new tank cars.

The figure below shows the existing and proposed takeaway capacity from the Western Canada Sedimentary Basin versus forecasted supply. Only current railway capacity is shown although this capacity could be increased significantly to fulfill future demand relatively quickly.

WCSB Takeaway Capacity vs. Supply Forecast



Capacity shown can be reduced by temporary operating and physical constraints.

TABLE OF CONTENTS

LIST OF FIGURES AND TABLES

Figures

Tables

1 INTRODUCTION

CAPP annually publishes its long-term outlook for Canadian crude oil production to provide a basis on which to build a common understanding among stakeholders, including industry, governments, and the general public regarding the growth in Canadian supply and the need for additional market access. This report also includes a summary of market opportunities available in North America and globally; and discusses the transportation projects being developed to connect the growing crude oil supplies to various markets.

Canadian crude oil production is expected to grow steadily to 2030. The oil sands represent the vast majority of Canada's crude oil reserves, so naturally this resource will be the primary driver for future overall growth. CAPP's estimate of industry capital spending on oil sands development is $23 billion for 2013, which is unchanged from the estimated expenditure for 2012. In addition, declining production from eastern Canada is offset by growth in conventional production from western Canada.

1.1 Production and Supply Forecast Methodology

CAPP surveyed oil producers in Saskatchewan regarding their annual drilling outlook by well type (horizontal or vertical), as well as their anticipated initial production rates. The conventional production by province component of the forecast was developed through internal analysis of historical trends, the Saskatchewan survey, expected drilling activity, recent announcements, and discussions with industry stakeholders and government agencies.

The oil sands component of the forecast is derived from CAPP's survey of all oil sands producers and as such, reflects the latest industry insight on factors such as production capability from individual projects and general market opportunities. In this analysis, production is not constrained by lack of any transportation infrastructure. However, the report does compare the supply that the analysis produces against the current and proposed pipeline and rail projects to determine where bottlenecks may occur. CAPP does not forecast crude oil prices. Producers responded to the survey with an outlook based on their own internal view of the long-term oil price. In this manner, CAPP is assuming that the oil price will be sufficient to make these projects economic so that this production will be available to the market.

Producers were surveyed for the following data:

a) expected production by project and phase;

b) upgraded light crude oil production; and

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

The survey results were then risked based on each project's stage of development. Past performance of each company's existing projects or phases was also considered in determining the pace of activity in future project stages, which is an important factor in the case of *in situ* projects that typically have their production capacity divided into multiple phases. The overall forecast was then verified for reasonableness against historical trends. No constraints were put on the forecast due to availability of condensate for blending purposes.

1.2 Market Demand Outlook Methodology

CAPP surveyed refiners in Canada and the U.S. to develop its market outlook. No risk adjustments were made to the responses. However, some assumptions based on discussions with refiners and publicly available information were made and EIA data was used to complete gaps in the survey data for actual demand for each region of the U.S.

2 | CRUDE OIL PRODUCTION AND SUPPLY FORECAST

Although crude oil is known primarily as a feedstock for transportation fuels such as gasoline, it is actually used in the manufacture of a wider range of products that include plastics and even pharmaceuticals. Not surprisingly, all the industrialized countries of the world are extremely dependent on crude oil. According to the EIA, Canada currently ranks as the sixth largest crude oil producing country in the world and remains the largest source of crude oil imports by the United States. The Oil & Gas Journal ranks Canada's 173 billion barrels of proven crude oil reserves as the world's third largest reserves after Venezuela and Saudi Arabia.

2.1 Canadian Crude Oil Production

In 2012, total Canadian production increased from 2011 levels by 223,000 b/d to over 3.2 million b/d and continued growth is forecast in the long term. Eastern Canada produced about 6 per cent, or 202,000 b/d of the total Canadian crude oil production. Western Canada produced 3.0 million b/d from combined conventional and oil sands production. Table 2.1 shows the forecast for total Canadian production divided between eastern and western Canada. Figure 2.1 shows the total Canadian production forecast. Conventional production from western Canada is expected to remain fairly constant at around 1.4 million b/d throughout the outlook period while production from the oil sands is expected to grow from 1.8 million b/d today to 5.2 million b/d at the end of the forecast period. It is this growth from oil sands production that drives the overall increase in current production levels from 3.2 million b/d to 6.7 million b/d in 2030.

Table 2.1 Canadian Crude Oil Production

million b/d	2012	2015	2020	2025	2030
Total* Canadian (including oil sands)	3.24	3.88	4.85	6.03	6.74
Eastern Canada	0.20	0.23	0.25	0.18	0.09
Western Canada	3.04	3.65	4.61	5.85	6.65

*Totals may not add up due to rounding.

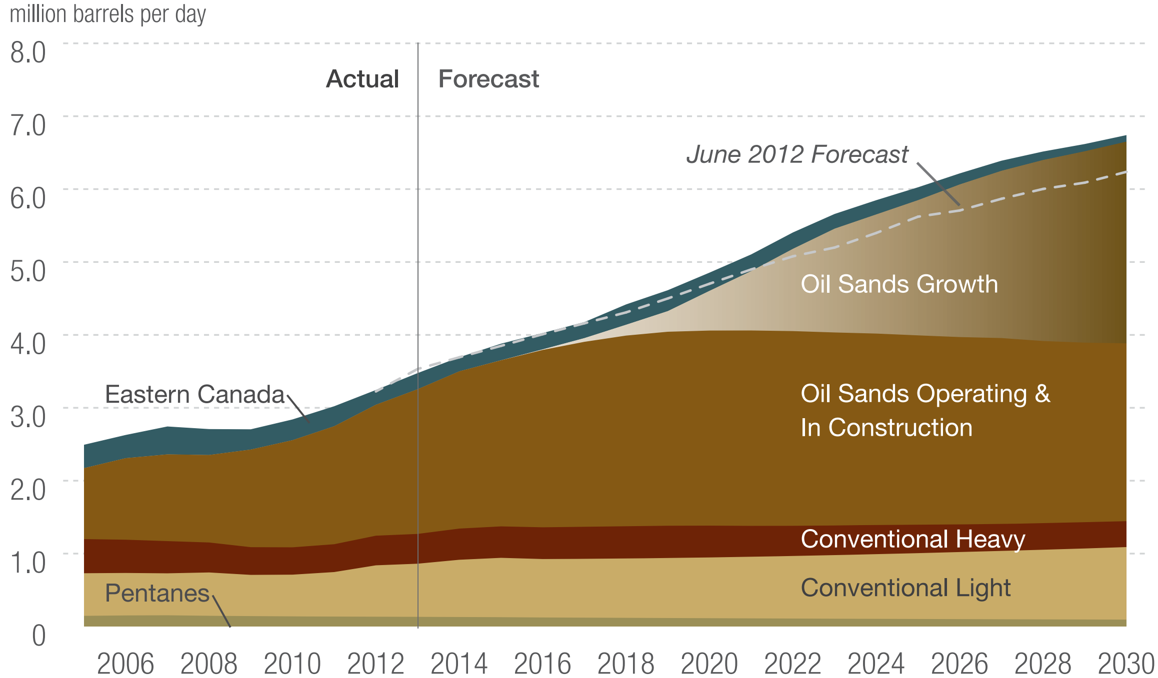
2.2 Eastern Canadian Crude Oil Production

Eastern Canada's crude oil production is sourced from Atlantic Canada supplemented by a small volume coming from Ontario. Since 2007, some minor volumes have been produced from New Brunswick but Atlantic Canada's oil resources are essentially being developed by three offshore oil projects: Hibernia, Terra Nova and White Rose, located off the shores of Newfoundland and Labrador. Continued drilling development at satellite fields associated with these projects (e.g. Hibernia South Extension, North Amethyst and West White Rose) has extended production at these facilities. First oil from Hebron, the fourth major project, is expected by the end of 2017.

In 2012, production declined by 26 per cent to 197,000 b/d. This decrease of 69,000 b/d from 2011 production mostly resulted from extended maintenance shutdowns and to a lesser extent, natural declines at all three projects. Hibernia was offline for 30 days between August and September; Terra Nova for 183 days between June and December and White Rose for 102 days between May and August. Production in 2013 is projected to increase due to a return to steady-state operations.

The outlook for Atlantic Canada production is slightly higher than forecast last year due to an increase in the reserve estimate for the Terra Nova field. In April 2013, the Canada-Newfoundland and Labrador Offshore Petroleum Board stated that it expected the field to operate until 2027, seven years more than it previously estimated.

Figure 2.1 Canadian Oil Sands & Conventional Production



2.3 Western Canadian Crude Oil Production

Western Canadian crude oil production can be divided between conventional and oil sands production. Both categories are expected to contribute significantly to the forecast outlook for western Canadian oil production (Table 2.2). Oil sands production essentially only occurs in the province of Alberta, while conventional resources underlie Alberta, northeast British Columbia, Saskatchewan and parts of Manitoba and the Northwest Territories.

Table 2.2 Western Canadian Crude Oil Production

million b/d	2012	2015	2020	2025	2030
Total*	3.04	3.65	4.61	5.85	6.65
Conventional (including condensate)	1.25	1.37	1.38	1.40	1.44
Oil sands (bitumen & upgraded)	1.80	2.28	3.22	4.45	5.21

*Totals may not add up due to rounding.

Relative to CAPP's 2012 report, production at the latter end of the outlook period from 2020 to 2030 is higher than previously forecast and shows an average annual growth of 200,000 b/d. Conventional production is forecast to contribute about 1.4 million b/d to the total output; the impact of the steep declines expected from mature fields is expected to be entirely offset by production from new horizontal wells. Compared to last year's forecast, conventional production is higher by 300,000 b/d in 2030. Oil Sands production is higher than previously forecast by 200,000 b/d in 2030 due to greater anticipated production from *in situ* wells.

2.3.1 Conventional Crude Oil Production

Conventional crude oil production from western Canada is benefiting from the application of horizontal multistage hydraulic fracturing in tight oil basins to reinvigorate mature basins, a recent trend that has been even more pronounced in the United States. Horizontal drilling has doubled or even tripled the percentage of the resource that industry expects to be able to recover from the reservoirs. Historically, conventional production had been declining steadily since 2002 but flattened out in 2011. Production, including condensates in 2012, was 1.2 million b/d, which returned production to levels not seen since 2004. Further growth is anticipated as conventional production is forecast to ultimately reach 1.4 million b/d despite a decline in condensate production which is primarily recovered from natural gas wells. In last year's report, conventional production was expected to increase in the next few years and then decline during the latter part of the forecast. This latest forecast, however, shows a revised outlook to reflect the expectation that production from new wells will more than offset the natural declines from existing wells in the next few years before maintaining production levels for the remainder of the forecast period. Most of the conventional production comes from Alberta and Saskatchewan and is primarily light crude oil (Figure 2.2). The split between heavy and light conventional crude oil will remain essentially constant to 2030.

Alberta

According to the Alberta Energy Resources Conservation Board (ERCB), out of the 3,107 new oil wells placed on production in 2012, horizontal wells, including those using multistage fracturing techniques, accounted for 2,379 or 77 per cent. This is more than double the number of new horizontal wells placed on production in 2010, the first year horizontal drilling really ramped up in the province.

There are six key shale oil formations in Alberta that have been identified to represent a crude oil in-place endowment of about 424 billion barrels. These formations are Duvernay, Muskwa, Montney, Banff/Exshaw, Nordegg and Wilrich. It is important though to differentiate this estimate from recoverable reserves. Typically recoverable reserves form less than 5 per cent of the in-place reserve estimate. Alberta is leading tight oil drilling activity in western Canada due to the potential of plays such as the Cardium and Viking.

In 2012, conventional Alberta oil production, excluding condensates, was 556,000 b/d and is forecast to increase by 257,000 b/d to 813,000 b/d by 2030. In contrast, in last year's report production was forecast to decline to 522,000 b/d by 2030. With only a few years of production data from horizontal wells, it is too early to establish the ultimate flow rates for wells drilled using the newer technology. However, if the early performance is any indication, CAPP's current forecast outlook may be conservative.

Saskatchewan

The Bakken play is widely recognized as the source of the skyrocketing production in North Dakota but the delineated play area also reaches into Montana, and Canada, including parts of Saskatchewan and a small portion of southwest Manitoba.

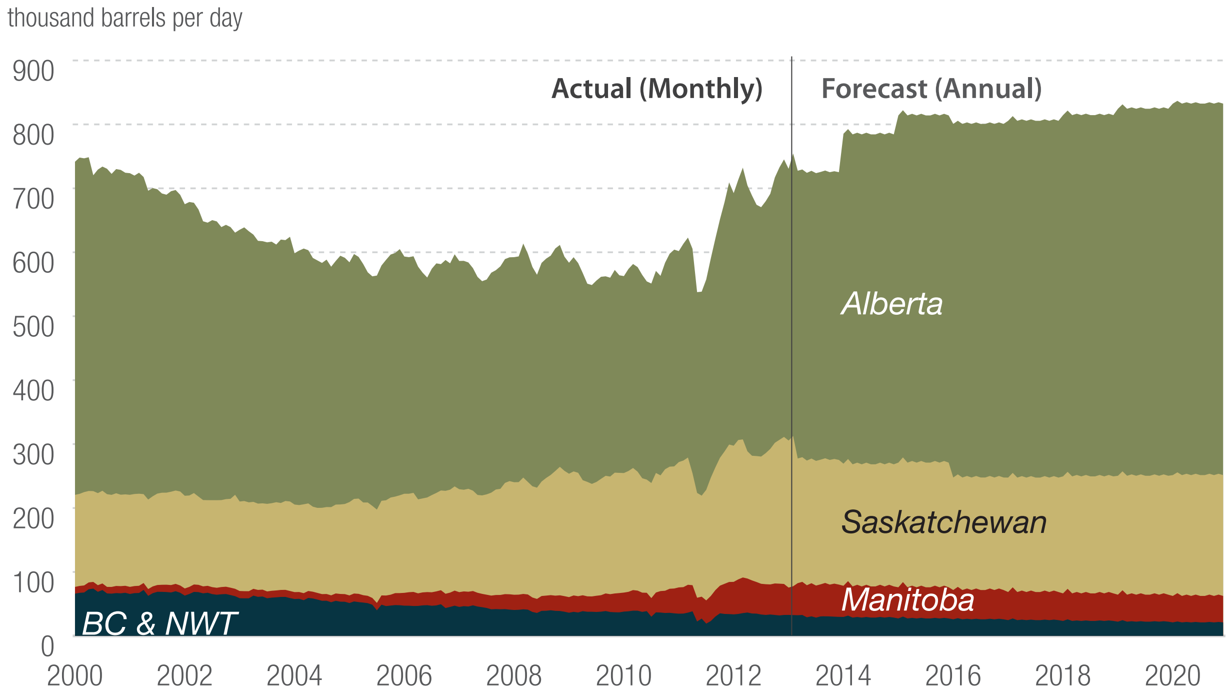
Total (light and heavy) Saskatchewan oil production is currently 470,000 b/d and is forecast to increase to 490,000 b/d by 2030. This is similar to last year's forecast. In 2012, CAPP initiated its survey of Saskatchewan oil producers and has surveyed them again in early 2013 for an update to their drilling plans. Robust drilling and production from horizontal wells is expected to generally grow production year over year throughout the forecast period.

Manitoba, NWT

Manitoba production has steadily increased from 2004 and has more than tripled since then but from a total Canadian context, Manitoba accounts for 7 per cent of light conventional production from western Canada.

Little production currently comes from the Northwest Territories but investment dollars are being attracted to one of North America's oldest fields – the Sahtu region of Canada's Northwest Territories (NWT). Canol oil shale in the NWT is attracting significant attention but assessments of this play are in the very preliminary stages.

Figure 2.2 Western Canada Conventional Production (Light & Medium) 2000-2020



2.3.2 Oil Sands

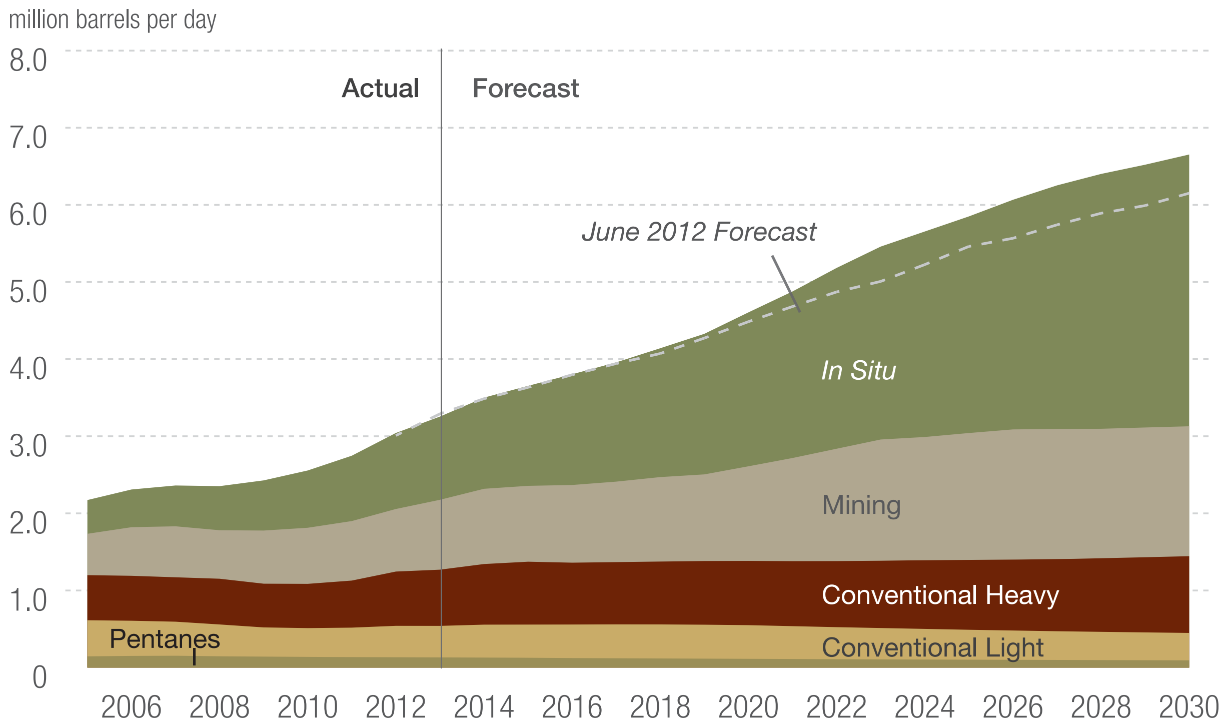
Three designated oil sands areas in northern Alberta have been defined and used to differentiate the extra heavy crude oil, produced from these regions, termed bitumen, from conventional crude oil production. The regions are referred to as the Athabasca, Cold Lake and Peace River deposits (Figure 2.3). The ERCB estimated at year-end 2012, that these areas contain remaining established reserves of 168 billion barrels.

Depending on the depth of the deposit, one of two methods is used to recover the bitumen. Surface or open pit mining can be used to recover bitumen that occurs near the surface. At greater depths, *in situ* techniques are employed. These refer to both, primary development, that uses methods similar to conventional crude oil production, and enhanced development techniques - the main methods being cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD).

Of the remaining established reserves in Alberta, 33 billion barrels or 20 per cent is considered recoverable by mining and 135 billion barrels or 80 per cent can be recovered using *in situ* techniques.

Figure 2.3 Oil Sands Regions

Figure 2.4 Western Canada Oil Sands & Conventional Production



Compared to CAPP's 2012 forecast, while this latest oil sands forecast is very similar in aggregate for most of the outlook period, this similarity is in fact the net result of a higher growth outlook for *in situ* production that offsets the lower growth outlook for mining production. In 2012, oil sands production totaled 1.8 million b/d. Of these volumes, 1.0 million b/d were recovered by *in situ* techniques. Mining production is forecast to grow up to 1.7 million b/d by 2030. Most of the growth is expected from *in situ* production, which is forecast to grow to 3.5 million b/d by 2030 (Table 2.3).

Table 2.3 Oil Sands Production

million b/d	2012	2015	2020	2025	2030
Total*	1.80	2.28	3.22	4.45	5.21
Mining	0.81	0.98	1.23	1.65	1.68
In Situ	0.99	1.30	2.00	2.81	3.52

*Total may not add up due to rounding.

Production volumes from oil sands are typically reported using the upgraded crude oil volumes from integrated projects instead of the raw bitumen volumes processed by these projects. The yield losses associated with upgraded bitumen volumes from non-integrated have been included in the supply volumes that are discussed in the next section of this report. Production from oil sands currently accounts for 59 per cent of western Canada's total crude oil production. In this forecast, oil sands production rises from 1.8 million b/d in 2012, to double in 10 years and reaches 5.5 million b/d by 2030 (Figure 2.4). The oil sands forecast by 2030, is approximately 200,000 b/d higher than forecast in the last report. Please refer to Appendix B.1 for detailed production data.

Currently, Nexen's Long Lake project is the only *in situ* project coupled with upgrading facilities whereas in contrast, historically all mined bitumen has been transformed into upgraded light crude oil. However, Imperial's Kearl mining project started producing bitumen at the end of April 2013 and is the first mining project operating without an affiliated upgrader. This project will deliver diluted bitumen to the market. Some *in situ* volumes from Suncor's Firebag project are upgraded at the Suncor upgrader.

Existing integrated operating and upgrading projects 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's Horizon Project.

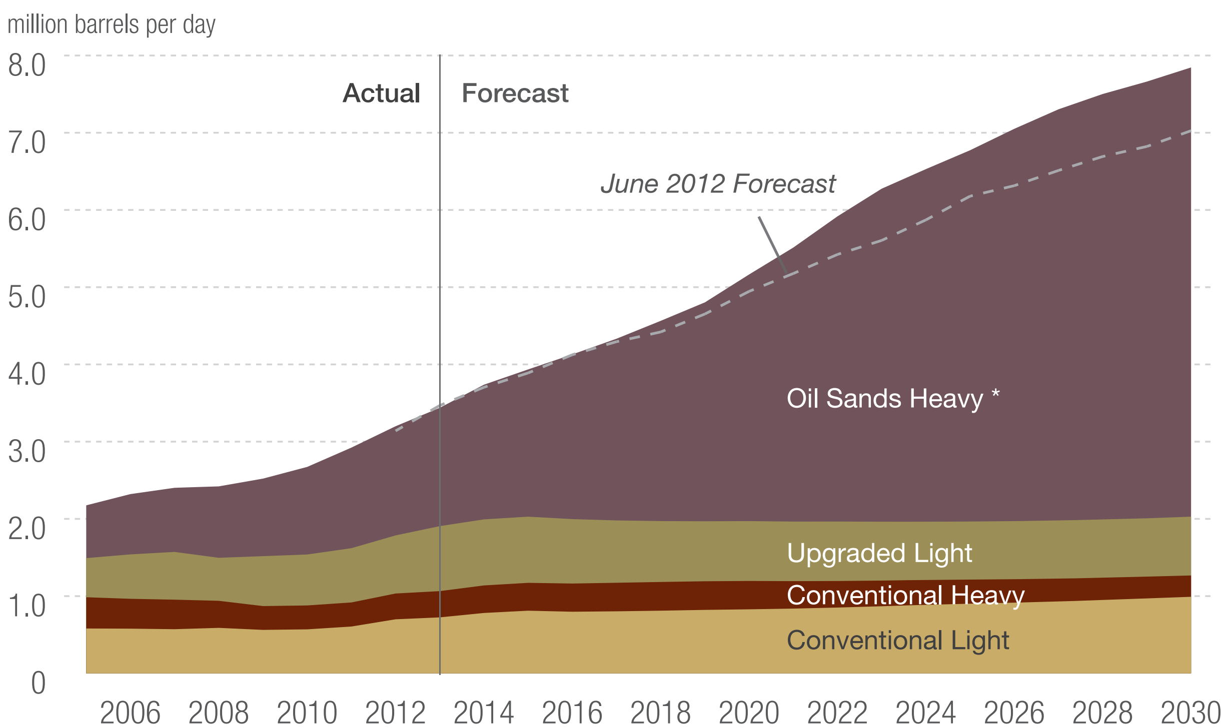
2.4 Western Canadian Crude Oil Supply

The composition of the various crude types available in the market differs from crude oil at the production level. Both conventional heavy crude oil and bitumen from oil sands are either upgraded or blended in order to be transported or to meet optimal refinery specifications. In addition, some volumes of light crude oil may also be used for blending. In any event, it is this crude oil supply that is available after upgrading and blending that is more relevant to market observers because it is these volumes that are ultimately delivered to the end-use markets.

In this report, CAPP categorizes the various crude oil types that comprise western Canadian crude oil supply into the following 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"). Blending for DilBit differs by project but requires approximately a 70:30 bitumen to condensate ratio while the blending ratio for SynBit is approximately 50:50. Bitumen volumes transported by rail are currently relatively minor; however, these volumes would require less diluent for blending versus moving by pipeline or may even be transported as raw bitumen (also known as "RailBit").

In 2012, about 1.0 million b/d or 58 per cent of the total bitumen produced in Canada was upgraded, including volumes of bitumen that were processed at the Suncor refinery in Edmonton. This refinery intake was included since it can process oil sands feedstock. Upgraded volumes are forecast to rise to 1.5 million b/d by 2030. The five bitumen upgraders located in Alberta produce a variety of upgraded products. Suncor produces light sweet crude and medium sour crudes, including diesel; Syncrude, Canadian Natural Horizon, and Nexen Long Lake produce light sweet synthetic crude; and Shell produces an intermediate refinery feedstock for the Shell Scotford refinery, as well as sweet and heavy synthetic crude.

Figure 2.5 Western Canada Oil Sands & Conventional Supply



* Oil Sands Heavy includes some volumes of upgraded heavy sour crude oil and bitumen blended with diluent or ugpraded crude oil.

Canada's upgrading capacity is not expected to rise proportionally as bitumen production rises due to a number of investment challenges. These include the high capital costs incurred with upgrading and the need for a sustained differential between light and heavy crude oil of at least $25 per barrel. It is difficult for a new upgrader to compete with the option of transporting heavy crude oil to existing refineries located throughout North America with spare coking capacity that are able to refine such heavy crudes.

If it is not upgraded, bitumen is so viscous at its production stage that it needs to be diluted with a lighter hydrocarbon or diluent to create a type of crude that meets pipeline specifications for density and viscosity. Bitumen at 10° Celsius has the consistency of a hockey puck and generally cannot be moved on pipelines. Less diluent is required when bitumen is moved by rail where it is transported in heated rail cars that lower the viscosity of the bitumen. The main source of diluent is condensate that is recovered from processing natural gas in western Canada. This source of condensate is declining while the needs of growing bitumen production already exceed this supply and continues to grow. In 2012, over 260,000 b/d of imported condensates, diluents from upgraders, as well as quantities of butane were needed to supplement the condensate supply from natural gas wells. 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 details on existing and proposed diluent import pipeline projects. The potential for bitumen to travel by rail with reduced diluent requirement has not been factored into the analysis of condensate demand but this would reduce the estimated need for diluent to the extent it becomes a significant transportation option.

Table 2.4 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 be relatively stable at around 1.6 million /d throughout the outlook. Heavy crude oil supply is projected to grow from 1.8 million b/d in 2012 to 3.6 million b/d in 2020 to more than triple the current volume in 2030, when it reaches 6.1 million b/d.

Table 2.4 Western Canadian Crude Oil Supply

million b/d	2012	2015	2020	2025	2030
Total*	3.20	3.94	5.16	6.77	7.85
Light	1.45	1.67	1.60	1.65	1.75
Heavy	1.75	2.27	3.56	5.12	6.09

*Total may not add up due to rounding.

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; and
- Off site upgraders, e.g., the Athabasca Oil Sands Project.

Compared to the 2012 forecast, the upgraded light crude oil supply is lower due to the announcement of some upgrader projects being cancelled. The Oil Sands Heavy category is forecast to increase from 1.4 million b/d to 5.8 million b/d by 2030 as a result of increased production volumes and higher imported diluent requirements for these additional non-upgraded volumes (Figure 2.5).

2.5 Crude Oil Production and Supply Summary

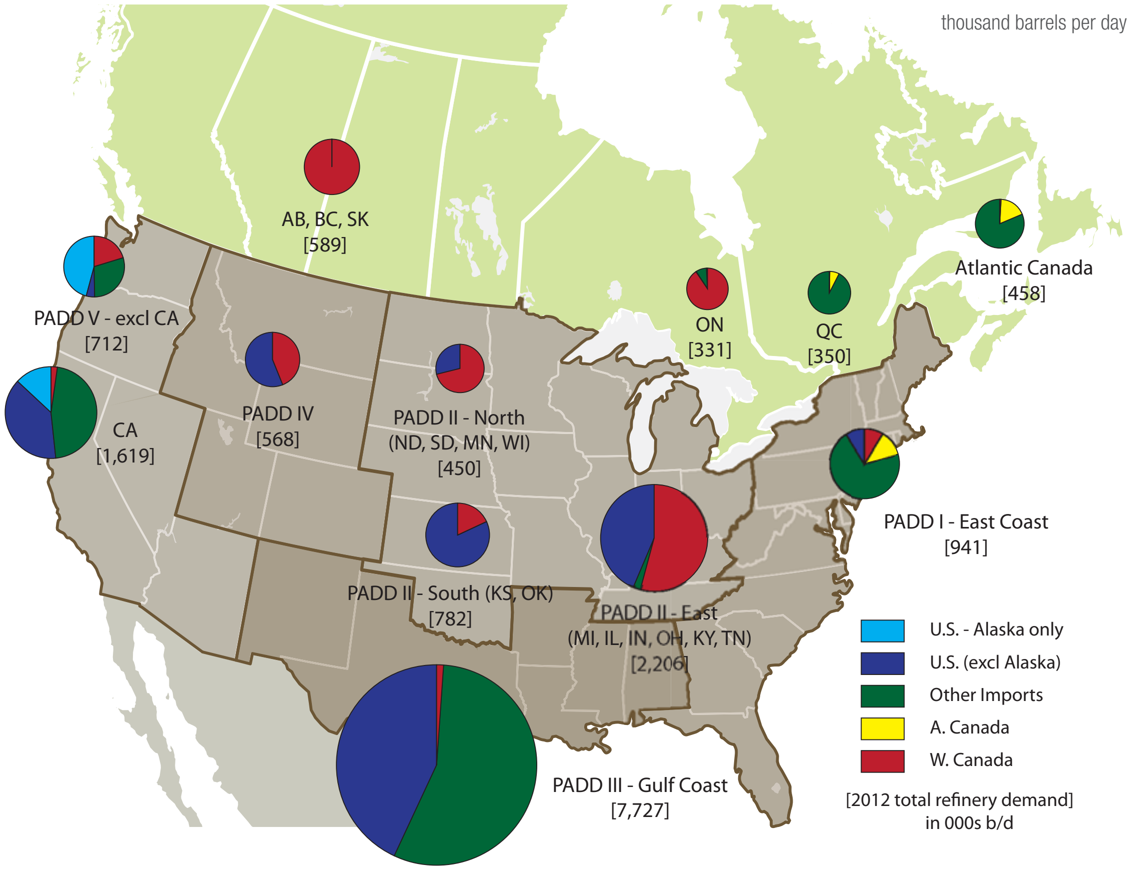
The production outlook in eastern Canada from offshore Atlantic Canada is expected to be stable at levels above 200,000 b/d until 2024, supported by production from satellite fields and the Hebron project starting up in 2017. This outlook has been revised slightly upward to reflect the Canada-Newfoundland and Labrador Offshore Petroleum Board's latest, higher reserve estimate for the Terra Nova field.

CAPP's 2013 production forecast predicts continued strong growth in western Canada and is higher than the previous outlook by 500,000 b/d by the end of the outlook in 2030. This is due to upward revisions primarily in the conventional category but also better performance from the oil sands than previously anticipated, specifically from *in situ* projects. The overall Canadian picture in terms of the supply outlook is 820,000 b/d higher in 2030 due to the cumulative effects of higher production, lower yield losses associated with less upgrading, and higher volumes of imported condensates needed to blend with the greater volumes of non-upgraded bitumen being produced.

3 | CRUDE OIL MARKETS

Given the growing production outlook discussed in the previous section, the need to reach new markets is a top priority for Canadian oil producers. This chapter examines the demand outlook for Canadian crude oil and reports on the new developments in both traditional and potential markets that could be reached. Figure 3.1 shows the relative demand for crude oil in the major refining regions in Canada and the United States. The Gulf Coast is a key target market in North America for Canadian producers due to the large amount of refining capacity and the ability to process heavy crude oil. There are also other opportunities in eastern Canada, particularly the refineries in Québec and the Atlantic provinces. New market opportunities are also emerging as a result of growing demand in Asia.

Figure 3.1 Canada and U.S. Market Demand for Crude Oil in 2012 by Source



Sources: CAPP, CA Energy Commission, EIA, Statistics Canada

In 2012, Canadian refineries processed 894,000 b/d of western Canadian crude oil. The remaining 2.3 million b/d or 72 per cent of available supplies was exported (Figure 3.2). PADD II is the largest regional market for western Canadian crude oil. Depending on the development of various rail and pipeline projects, refineries in eastern Canada have indicated a potential doubling of current demand for western Canadian crude oil by 2020. In addition, demand from refineries in the U.S. Gulf could reach over 1 million b/d.

3.1 Canada

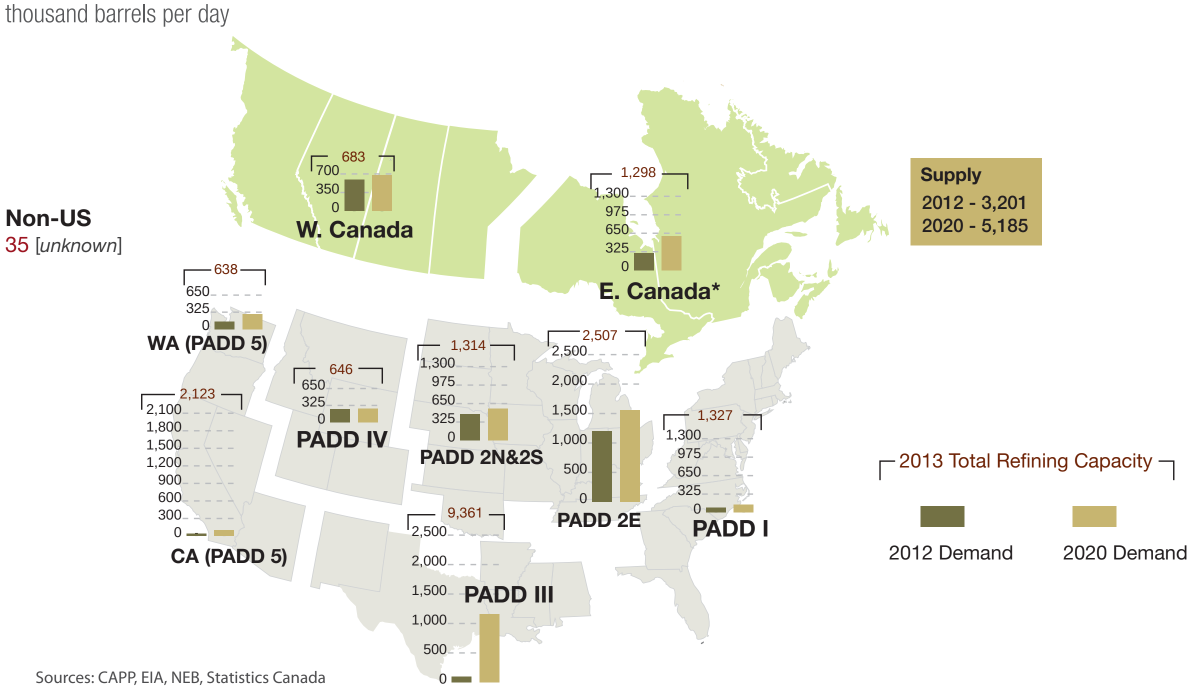
Canadian refineries have the capacity to process almost 2 million b/d of crude oil. However, only about 60 per cent of the crude oil processed in Canada is sourced from domestic production since refineries in eastern Canada have only limited access to western Canadian crude oil supplies. In 2012, Canadian refineries processed 894,000 b/d of western Canadian crude oil; 110,000 b/d of crude oil produced in eastern Canada; and 722,000 b/d of foreign imports. The current oil pipeline network exiting western Canada is connected to refineries in western Canada and Ontario. Based on data from Statistics Canada, in the last two years, Québec refineries have received small volumes of western Canadian crude while Atlantic Canada refineries received crude oil from western Canada for the first time in July 2012. Some refineries are developing transportation solutions involving rail and/or trucks to diversify their supply portfolio. The domestic demand for western Canadian crude oil is expected to increase to 1.3 million b/d by 2020 as a result of planned refinery expansions and future transportation infrastructure developments.

3.1.1 Western Canada

The eight refineries located in western Canada have a total refining capacity of 683,000 b/d. In 2012, they refined 589,000 b/d of crude oil that was sourced exclusively from western Canada. By 2020, western Canadian crude oil should remain the sole feedstock for these refineries and demand is expected to increase by 86,000 b/d to 675,000 b/d (Figure 3.3). Future additional crude oil receipts are related to a debottlenecking project at the Moose Jaw refinery, expansion plans at the Consumers' Co-operative Complex refinery, which are both located in Saskatchewan, and the startup of the Sturgeon refinery near Redwater in Sturgeon County, about 45 km northeast of Edmonton, Alberta. The Moose Jaw refinery is an asphalt refinery while the other refineries produce a wide range of petroleum products.

Figure 3.2 **Market Demand for Western Canadian Crude Oil: Actual 2012 and 2020 Additional**

thousand barrels per day

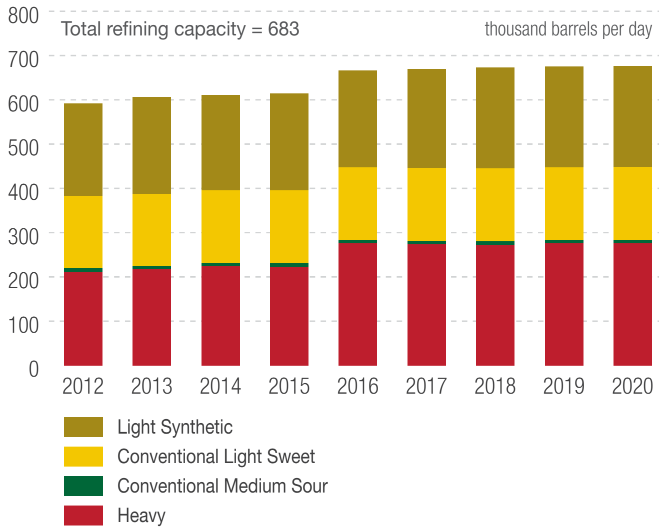


Sources: CAPP, EIA, NEB, Statistics Canada

* E.Canada demand for W. Canadian crude oil in 2012 consisted almost entirely of receipts from Ontario. Projected receipts in 2020 include growth from Québec and Atlantic provinces.

Note: 2012 demand exceeds available supply likely due to factors such as inventory adjustment and data discrepancies in information collection.

Figure 3.3 Western Canada:
Crude Oil Receipts from Western Canada



Source: 2013 CAPP Refinery Survey

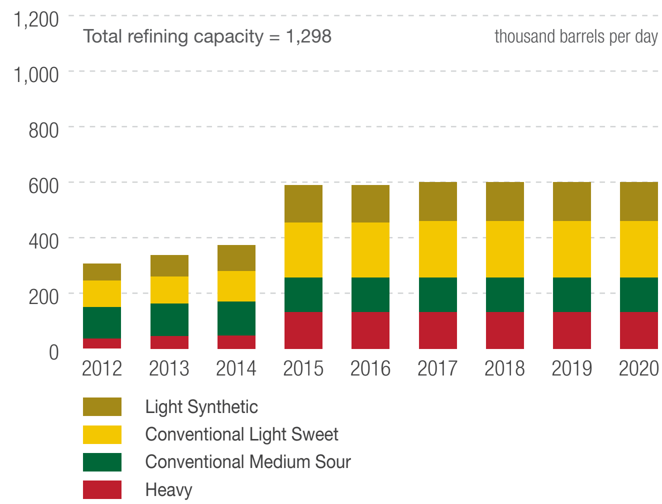
North West Redwater Partnership's proposed Sturgeon refinery will take bitumen feedstock with its first phase designed to process 50,000 b/d. Partners are North West Upgrading Inc. and Canadian Natural Upgrading Ltd., a wholly owned subsidiary of Canadian Natural Resources Ltd. The Alberta Petroleum Marketing Commission, an agent of the province of Alberta, will supply 75 per cent of the feedstock under 30-year processing agreements and Canadian Natural will supply the rest. The suppliers will receive proportionate shares of the products. Construction is planned to start in spring of 2013 and projected to take three years. Two additional phases that would each provide capacity of 50,000 b/d are envisioned for the refinery. The main product will be ultralow-sulphur diesel.

Newspaper publisher, David Black has announced a proposal to build a $13 billion, world-scale, export refinery in Kitimat, British Columbia. The refinery would be designed specifically to process DilBit and would be capable of processing 550,000 b/d; it could be operating by 2020.

3.1.2 Eastern Canada

Total capacity of refineries in eastern Canada is about 1.3 million b/d and includes the refineries located in Ontario, Québec and Atlantic Canada. In 2012, western Canada supplied 340,000 b/d to these refineries amounting to only 29 per cent of total refinery demand. Almost all of these receipts were delivered to Ontario. It should be noted, however, that the refineries in the other eastern provinces have just started to receive western Canadian supplies via rail. By 2020, overall demand in this market for western Canadian crude oil is expected to increase significantly if the Enbridge Line 9 reversal project and the TransCanada Energy East project proceed (Figure 3.4).

Figure 3.4 Eastern Canada:
Crude Oil Receipts from Western Canada



Source: 2013 CAPP Refinery Survey

Ontario

The four refineries located in Ontario have a combined refining capacity of 393,000 b/d. The Nova Chemical refinery and petrochemical complex, located in Sarnia, is not included in this number as crude oil is not the primary feedstock. The majority of the crude processed at the Ontario refineries is sourced from western Canada but they also refine some foreign imported crude oil and crude oil transferred 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 plans to re-reverse the direction of Line 9 to flow east from Sarnia, Ontario to Montréal, Québec. It is already in the process of of reversing the first phase of the project which would enable crude oil to flow east from Sarnia to North Westover, Ontario in 2013. Once in service, this first phase could provide light crude oil to Imperial's refinery in Nanticoke, Ontario. Refer to Section 4.6 for details on oil pipelines to Eastern Canada. Ultimately, all refineries in the region will have access to a variety of sources and will select their feedstock based on availability and price.

According to Statistics Canada, Ontario refineries received 366,200 b/d of crude oil. A further breakdown of these supplies shows 336,700 b/d (92 per cent) from domestic sources; 17,700 b/d (5 per cent) from the North Sea; 3,800 b/d (1 per cent) from Venezuela; 1,700 b/d (0.5 per cent) from the U.S.; and 6,400 b/d (2 per cent) from other foreign sources.

Québec & Atlantic Provinces

Québec has two refineries with a combined capacity of 402,000 b/d while the three Atlantic refineries have total capacity of 503,000 b/d. The crude oil processed at these refineries generally originates from either Atlantic Canada or foreign sources. Of note, Statistics Canada data indicated that the Québec refineries have received small volumes of western Canadian crude since 2011. Valero has recently announced plans to build rail off-loading facilities at its refinery in Levis, Québec in order to receive more volumes of light western Canadian crude oil. Despite the considerable distance, Atlantic Canada also received western Canadian crude oil deliveries in 2012 by rail. These refineries are designed to process mostly light crude oil.

If Enbridge's Line 9 re-reversal proposal is successful, western Canadian crude oil could be transported by pipeline to Montréal and then further in the province by alternative modes of transport. Refineries in these provinces would have access to the growing light oil production from both 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 the Irving refinery in Saint John, New Brunswick. In the meantime, the Irving refinery is expected to receive a regular supply of Bakken crude oil by rail. Its first shipment, in June 2012, was 72,000 barrels aboard a 102 car unit train. By 2018, TransCanada's Energy East pipeline project proposes to provide pipeline access from western Canada to Québec City and all the way to Saint John, New Brunswick.

3.2 United States

Canada and the U.S. are natural trading partners due to their geographic proximity. Canada is the top foreign supplier of crude oil to the U.S. while the U.S. is almost Canada's only market. New U.S. production from enhanced drilling programs in the shale and tight oil plays in the Eagle Ford and Permian basins in Texas and Bakken in North Dakota, have caused a displacement of foreign imports of light crude oil. Despite this fact, imports from Canada grew by 200,000 b/d or 9 per cent versus 2011. Growing western Canadian crude oil supplies are predominately heavy crude oil, therefore, the U.S. Gulf Coast refineries, with their substantial heavy oil processing capabilities, remain a key target market.

The U.S. Department of Energy divides the 50 states into five market regions termed the Petroleum Administration of Defense Districts or PADDs. These PADDs were originally created during World War II to help allocate fuels derived from petroleum products. Today, this delineation continues to be used to describe the U.S. market regions.

3.2.1 PADD I (East Coast)

Since a portion of previously idled refinery capacity restarted in 2012, the refining capacity on the U.S. East Coast now totals 1.3 million b/d. The 10 refineries that form this capacity are located in the states of Delaware, Georgia, New Jersey, Pennsylvania, and West Virginia. Table 3.1 summarizes the refining capacity developments in this region.

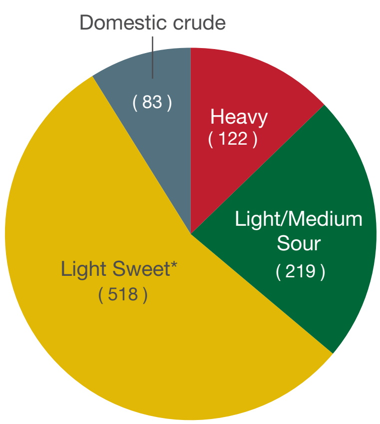
Most of the refineries in the region process light sweet crude (Figure 3.5). In 2012, imports of foreign crude oil by refineries in PADD I totaled 941,000 b/d, which is significantly lower than in 2011. This decline was due to a combination of some refining capacity being idled for most of the year and some displacement of foreign imports with growing domestic supplies. In 2013, there should be an increase in the total volumes processed in the region given that some previously idled refineries have returned to operations (Table 3.1). The boom in U.S. shale has presented a new source of supply for refineries in this region.

Table 3.1 Summary of Recent Refinery Developments in PADD I

Operator	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Description
Monroe Energy LLC	Trainer, PA	185	restarted Sep 2012 (previously idled since Sep 2011)	Monroe Energy LLC, a wholly owned subsidiary of Delta Airlines, purchased the idled refinery in April 2012; The transaction closed in Sep 2012 and the refinery has restarted.
PBF Energy	Delaware City, DE	190	restarted Oct 2011	PBF purchased the refinery in an idled state from Valero in June 2010. The refinery was idle from Nov 2009 to Oct 2011.
Philadelphia Energy Solutions	Philadelphia, PA	330	July 2012	Although it continued operations, Sunoco had announced that it would close the refinery if no buyer was found. In July 2012, the Carlyle Group announced a 50/50 joint venture with Sunoco to create Philadelphia Energy Solutions, a new entity that would own and operate the refinery.
Sunoco	Marcus Hook, PA	175 (loss)	shutdown Feb 2012	The refinery was idled since Dec 2011. Sunoco shut down the refinery in Feb 2012.

Figure 3.5 2012 PADD I: Foreign Sourced Supply by Type and Domestic Crude Oil

Total refining capacity** = 1,327 thousand barrels per day



* Includes small volumes of Medium Sweet

** Capacity as of Jun 2013; two refineries were idled in late 2011

Source: EIA

The east coast refineries are primarily supplied by waterborne crude delivered from the U.S. Gulf Coast and internationally-sourced crude. However, with the development of new rail unloading facilities, a number of the east coast refineries have growing access to Bakken crude oil produced in North Dakota. Phillips 66 and PBF Energy have signed agreements for Bakken crude supplies for its east coast refineries. There was also speculation that growing production from the Utica shale would present another prospect for increased domestic supplies of crude in the future. Given the fact these volumes would originate in Ohio, these crude oil supplies would need to travel a much shorter distance by rail to reach refineries on the east coast. However, recent reports suggest that the future potential from the Utica shale is more gas prone.

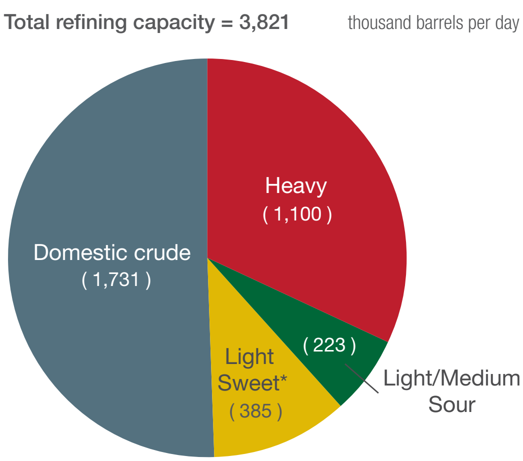
PADD I refineries imported 194,300 b/d of crude oil from Canada in 2012. About 64,800 b/d was sourced from western Canada and was primarily delivered to the United refinery in Warren, Pennsylvania.

Imports of heavy crude oil from western Canada could rise in the next few years via deliveries by rail. PBF Energy has made significant investments in its rail unloading facilities in 2012 for its Delaware refinery and intends to expand this capacity in 2013. PBF Energy's current rail unloading facility has 110,000 b/d of capacity comprised of about 40,000 b/d of heavy crude oil capacity and 70,000 b/d for light crude oil. The company also plans to increase heavy unloading capacity by another 40,000 b/d by Q4 2013. Although PBF Energy's Paulsboro refinery does not have a rail unloading facility, crude oil could be moved by barge from the Delaware facility up river to Paulsboro.
PBF Energy's Paulsboro and Delaware City refineries and NuStar Energy's asphalt refinery in New Jersey are the only refineries on the east coast with the coking capacity to process heavy bitumen blends from western Canada.

3.2.2 PADD II (Midwest)

Over 3.8 million b/d of refining capacity is located in PADD II. In 2012, these refineries received 1.7 million b/d of foreign sourced crude oil, almost all of which was from western Canada and were predominantly heavy supplies (Figure 3.6). In 2012, this market absorbed almost all of the growth in western Canadian supplies.

Figure 3.6 2012 PADD II: Foreign Sourced Supply by Type and Domestic Crude Oil



* Includes small volumes of Medium Sweet
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 Midwest region is currently Canada's largest market due to its close proximity, large size and established pipeline network. However, this traditional market has become saturated as evidenced by the high level of inventories from growing domestic production and imports from western Canada. A number of refineries have recently been upgraded to increase the heavy oil processing capacity in the region, which accounts for most of the expected growth in heavy oil demand.

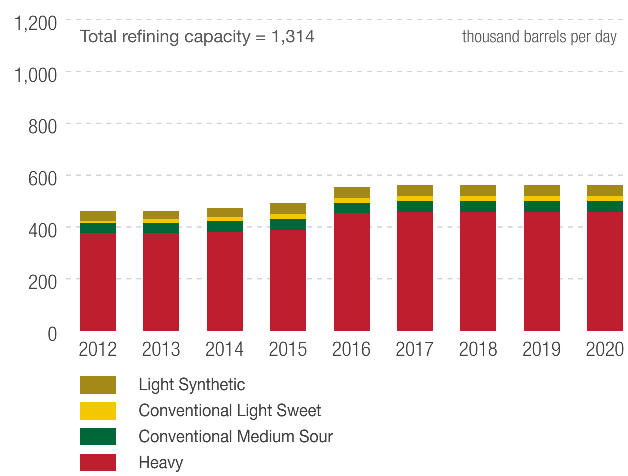
Northern and Southern PADD II

There are four refineries in Northern PADD II; two that are located in Minnesota, and one each in North Dakota and Wisconsin. These refineries have a combined capacity of 507,000 b/d. In 2012, imports from western Canada totaled 320,000 b/d and were the only source of foreign imports. These foreign imports comprised over 70 per cent of the total crude oil feedstock demand in the region. Approximately 89 per cent of these volumes were heavy crude oil supplies.

The seven refineries in Southern PADD II, all of which are located in Kansas or Oklahoma, account for a combined capacity of 807,000 b/d. Almost all of the foreign imports into the region were also sourced from western Canada but in contrast to Northern PADD II, U.S. domestic production satisfies most (over 80 per cent) of the feedstock demand for these refineries. The majority, or 66 per cent, of the 142,000 b/d of western Canadian crude oil imports were heavy oil supplies.

Given the small relative size of these two markets and increased competition with U.S. light oil production the growth in demand for western Canadian crude oil is limited. It is forecast to grow by 100,000 b/d by 2020 (Figure 3.7).

Figure 3.7 PADD II (North & South): Crude Oil Receipts from Western Canada



Source: 2013 CAPP Refinery Survey

Table 3.2 Summary of Recent Refinery Upgrades in Northern PADD II

Operator	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Description
Northern Tier Energy LP	St. Paul Park, MN	82	Completed May 2013	A 10% expansion of its crude distillation unit. Capacity increased from 72,000 b/d.
Tesoro	Mandan, ND	68	Completed June 2012	Increased crude capacity by 10,000 b/d to 68,000 b/d to process more Bakken crude oil.

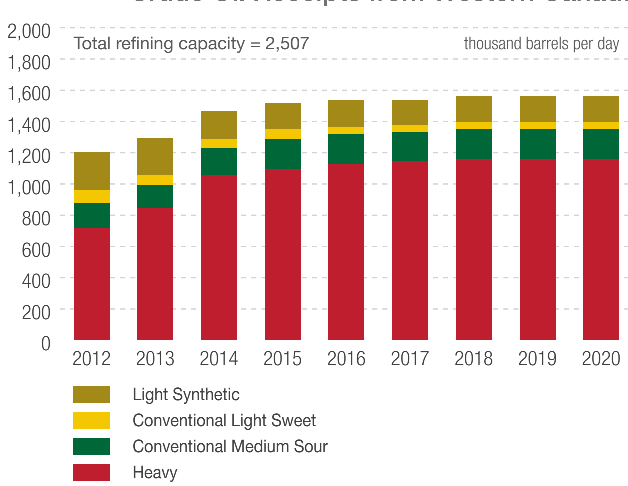
Table 3.3 Summary of Recent Refinery Upgrades in Eastern PADD II

Operator	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Description
WRB Refining	Roxana, IL	306	Completed Nov 2011	New 65,000 b/d coker; increased total crude oil refining capacity by 50,000 b/d and heavy oil capacity to 240,000 b/d.
BP	Whiting, IN	413	2H 2013	Construction of 70,000 b/d new coker and a new crude distillation unit. The modernized refinery will have the capacity to process up to 85% heavy crude vs 20% currently
Marathon	Detroit, MI	120	Completed Nov 2012	Increase heavy oil processing capacity by 80,000 b/d; total crude oil refining capacity increased by 14,000 b/d.

Eastern PADD II

The total refining capacity in Eastern PADD II is over 2.5 million b/d from 13 refineries located throughout the six states of Michigan, Illinois, Indiana, Kentucky, Tennessee and Ohio. In 2012, this market collectively imported over 1.2 million b/d of crude oil supplies, of which 97 per cent were sourced from western Canada. Imports of heavy western Canadian crude oil are estimated to increase from current levels by over 400,000 b/d by 2020 (Figure 3.8) with the completion of a number of previously announced refinery projects designed to increase heavy oil processing capacity at various refineries. Although the BP refinery in Whiting, Indiana is anticipated to come on stream in the second half of 2013, the refinery is not expected to operate its full heavy processing capacity until 2014. Table 3.3 summarizes the recent and upcoming refinery upgrades announced for Eastern PADD II.

Figure 3.8 PADD II (East): Crude Oil Receipts from Western Canada



Source: 2013 CAPP Refinery Survey

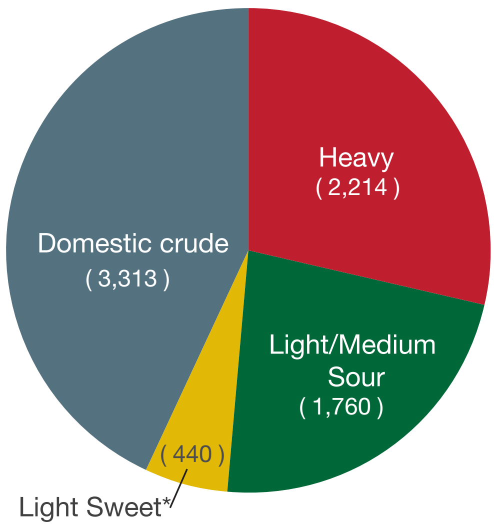
3.2.3 PADD III (Gulf Coast)

The U.S. Gulf coast area has a capacity of 9.4 million b/d from 50 refineries. Refineries are located in Alabama, Arkansas, Louisiana, Mississippi, New Mexico and Texas. Louisiana and Texas account for the vast majority of refining capacity in this region with 8.6 million b/d.

Foreign imports of crude oil totaled 4.4 million b/d in 2012, of which 2.2 million b/d was heavy crude oil. Only 100,000 b/d of western Canadian crude was able to reach the U.S. Gulf Coast region due to limited pipeline infrastructure. As a result of surging production from U.S. shale and tight oil plays such as the Eagle Ford and Permian Basin in Texas, some refineries along the U.S. Gulf Coast no longer import light-sweet crude since domestic production is available to fill their feedstock requirements. Venezuela, Mexico, Columbia and Brazil collectively account for 88 per cent of all heavy imports into the region, with Mexico and Saudi Arabia each accounting for 22 per cent and Venezuela following closely at 20 per cent. Crude oil imports from Saudi Arabia consist mostly of light and medium sour crude oil types. The opportunity for growing supplies from western Canada lies in the displacement of heavy imports that does not directly compete with U.S. domestic production, which is primarily comprised of light crude oil. In addition, some refineries are also contemplating blending Canadian heavy crude oil with Eagle Ford light oil to create a medium sour crude oil that could displace additional offshore imports (Figure 3.9).

Figure 3.9 2012 PADD III: Foreign Sourced Supply by Type and Domestic Crude Oil

Total refining capacity = 9,361 thousand barrels per day



* Includes small volumes of Medium Sweet
Source: EIA

Crude oil imports from Mexico fell by 130,000 b/d to below 1 million b/d for the first time since 1994, reflecting the steady decline in Mexico's crude oil production. Venezuelan imports have declined 27 per cent from 2005 levels to 906,000 b/d in 2012, a trend that will likely continue as Venezuela increases exports to China.

Despite Venezuela having the world's largest reserves of crude oil and announcing projects designed to increase production capacity by over 2 million b/d, growth in Venezuelan production will be difficult to achieve. There has been substantial under investment in the oil industry as a result of diverting oil revenues to fund social programs and considerable investments will be needed to just offset the decline in production from the mature fields. If there is no substantial growth in production, exports to the U.S. will be limited as Venezuela has substantial supply commitments to China, Cuba, the Dominican Republic and Nicaragua.

There are three new pipeline projects planned for operations over the next three years that will be major conduits between western Canadian producers and the Gulf Coast market. 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 3.4 summarizes the recently completed major refinery upgrades and future upgrades announced for the region.

Table 3.4 Summary of Recent Refinery Upgrades in PADD III

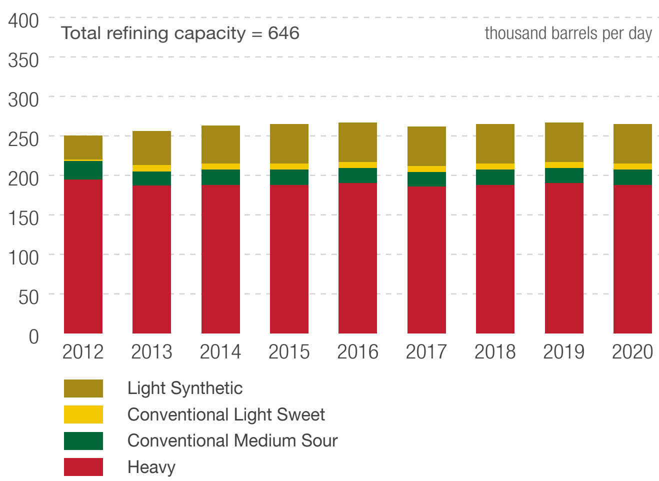
Operator	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Description
Motiva Enterprises	Port Arthur, TX	285	2012	Addition of new single-train distillation unit with capacity of 325,000 b/d that would increase total capacity to over 600,000 b/d. New 95,000 b/d delayed coker; 85,000 b/d catalytic reformer, 75,000 b/d.
Valero	McKee, TX	170	2014	Increase capacity by 25,000 b/d. Expansion will process WTI and locally produced crude oil.
Valero	Port Arthur, TX	310	Q3 2012	New hydrocracker.
Valero	Norco, LA	250	Q4 2012 completed	New hydrocracker. Recently completed FCC revamp. Ramp up to full operations by Q2 2013.
LyondellBasell Industries NV	Houston, TX	268	2015	Increase ability to process heavy crude oil from 60,000 b/d to 175,000 b/d.

3.2.4 PADD IV (Rockies)

There are 17 refineries throughout Colorado, Montana, Utah, and Wyoming representing the refining capacity in PADD IV. The total refining capacity in this market region is 646,000 b/d and all foreign imports are sourced from western Canada.

In 2012, PADD IV refineries processed 250,000 b/d of Canadian crude oil, representing 44 per cent of total feedstock requirements in the region. Receipts of heavy western Canadian supply are forecast to remain steady with slight growth in light synthetic volumes anticipated in 2013, which level off thereafter (Figure 3.10). If Canadian heavy crude oil continues to be priced at an attractive discount, refineries are expected to continue to take heavy volumes to optimize refinery configuration despite the light crude oil surplus in the region.

Figure 3.10 PADD IV: Crude Oil Receipts from Western Canada

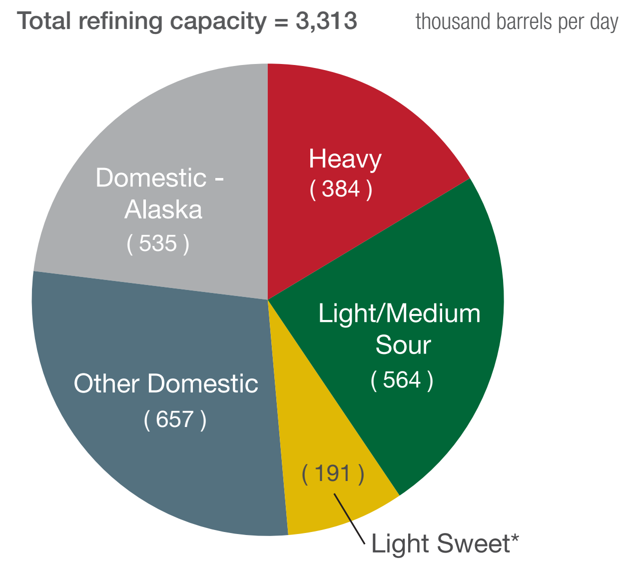


Source: 2013 CAPP Refinery Survey

3.2.5 PADD V (West Coast)

PADD V is geographically divided from the rest of the U.S. by the Rocky Mountains and this geographical isolation has affected the development of crude supply sources to the region. The states in PADD V that have refineries are Alaska, California, Hawaii, and Washington. These refineries are located in close proximity to production in California and Alaska and also have good access to tankers that can import crude from more distant regions. There is over 3.3 million b/d of refining capacity in the region. Foreign imports typically supply around 50 per cent of the crude oil feedstock demand (Figure 3.11) and this share is expected to supplement the declining production from Alaska.

Figure 3.11 2012 PADD V: Foreign Sourced Supply by Type and Domestic Crude Oil



* Includes small volumes of Medium Sweet
Source: EIA

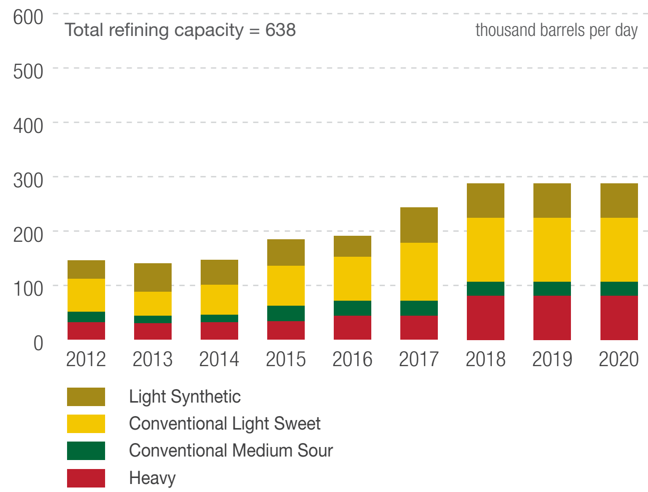
The following section only focuses on Washington and California as demand from the refineries in these states account for both current and future prospects for western Canadian crude oil in this region.

Washington

Refining capacity in Washington totals 638,000 b/d. There is no indigenous crude oil production within the state so its five refineries have been primarily supplied with Alaskan production delivered by tanker. However, Alaskan production has fallen dramatically from its peak in 1988 of over 2 million b/d to only 525,000 b/d in 2012. The Washington refineries have become increasingly dependent on foreign imports but some have also recently been able to start using rail to access some of the growing crude oil production supply in North Dakota.

In 2012, Washington refineries received 241,000 b/d of foreign imports, 81 per cent of which was supplied by the top three sources – Canada (60 per cent); Russia (13 per cent); and Angola (8 per cent). Results from CAPP's refinery survey indicate crude oil demand from western Canada doubling in 2020 from current levels (Figure 3.12). This growth in demand relies on the successful construction of proposed pipeline projects that would reach the west coast. Refer to Section 4.5 Pipelines to the West Coast for details.

Figure 3.12 **Washington: Crude Oil Receipts from Western Canada**



Source: 2013 CAPP Refinery Survey

In 2012, Washington started to receive deliveries of light sweet North Dakota Bakken crude oil by rail. Continued investment in rail facilities has been announced to primarily enable receipts of additional volumes from this supply source and accommodate deliveries from western Canada as well. Phillips 66 has announced plans to build a rail offloading facility at its Ferndale refinery to receive both Bakken and western Canadian crude oil.

California

California dominates PADD V in terms of state production and refining capacity. There are 16 refineries, almost all of which are located near the coast in the Los Angeles and the San Francisco Bay areas and contribute a total refining capacity of 2.1 million b/d. There is no direct pipeline access to neighboring producing regions so domestic supplies have historically come from indigenous supplies and shipments by tanker from Alaska.

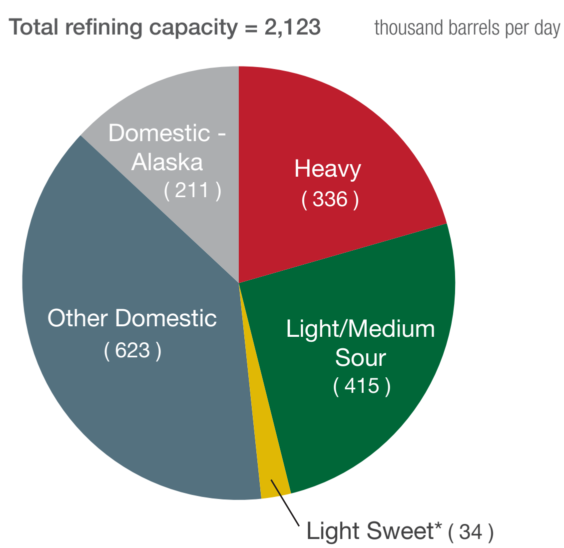
The steady decline in California production seen since 1997 has stabilized in the last two years. Recent surveys from the U.S. EIA have indicated that 15.4 billion barrels of oil (64 per cent) of the total recoverable shale oil in the U.S. can be found in California. Notable plays include the Monterey Shale in southern and central California and the Kreyenhagen. Although California's potential growth in unconventional oil production is enormous, there are many challenges to overcome before significant commercial production develops. For example, an efficient regulatory framework still has to be developed, the appropriate stimulation techniques have to be identified and even then the costs of development could still be prohibitively high.

In the meantime, as Alaskan crude oil production continues to decline, an opportunity has risen for supplemental supplies to serve the state from the Bakken in North Dakota and potentially Canada. Western Canadian crude oil can reach this market either on the Trans Mountain pipeline to the Westridge dock or by rail to the west coast where it would be loaded onto tankers. The Enbridge Gateway pipeline and the Trans Mountain Pipeline Expansion projects represent future opportunities for greater Canadian access to the California market. Direct pipeline access to this market is unlikely due to its limited size but there could potentially be increased access through rail.

Development of rail terminal infrastructure has been slower in California than in Washington due to a more complicated permitting process. Tesoro has announced plans to unload trains in Washington and then transfer the crude to vessels for further distribution to its refineries in California by 2014. Valero has announced plans for rail unloading facilities at its refinery at Benicia, near San Francisco that is scheduled to be completed in mid-2014. The current plans are for receipts of up to 70,000 b/d of crude oil from North Dakota and Montana or western Canada.

In 2012, California refineries imported 784,400 b/d of crude oil from foreign sources (Figure 3.13). Almost two-thirds of these imports were sourced from Saudi Arabia (27 per cent); Ecuador (19 per cent); and Iraq (18 per cent). Canada accounted for only 5 per cent of total foreign imports.

Figure 3.13 **2012 PADD V (California): Foreign Sourced Supply by Type and Domestic Crude Oil**



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

3.3 Asia

At an aggregate level, demand for oil in North America is either flat or even declining but the demand for crude oil and petroleum products in the Asia-Pacific countries comprises the fastest growing in the world. Table 3.5 shows oil demand from 2010 to 2013 in major Asian markets. Western Canadian oil producers are essentially land-locked and need tidewater access to gain market share in what is now the world's premium crude oil market. The earliest in service date for any of the proposed pipeline projects to the west coast to reach this market is at the end of 2017.

China and India are two of the fastest growing economies in the world and naturally, their demand for oil is growing accordingly (Figure 3.14). China's current ability to process large volumes of heavy crude oil from Canada may be limited but new refineries with high conversion capacity are being built due to China's higher demand for diesel fuel versus gasoline. Generally speaking, refineries able to process heavy crude oil can increase their production of diesel more easily than those configured to process light crude oil. Heavy crudes typically yield greater quantities of heavier and less valuable residual fuel oil. That residual fuel oil can then be converted to increase the yield of middle distillates such as diesel.

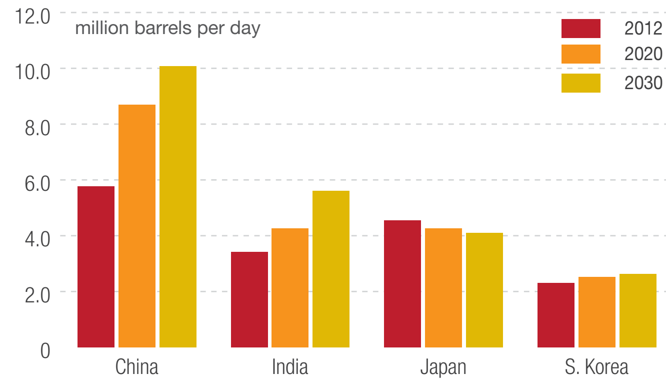
Indian Oil Corp., India's largest refining company has expressed interest in investing in Canada's oil sands with the intent to gain access to these supplies for export but the lack of transportation infrastructure, specifically pipelines, remains an obstacle. Continued delays in establishing tidewater access could translate into a foregone opportunity to serve these large markets.

Table 3.5 Total Oil Demand in Major Asian Countries

million b/d	2010	2011	2012	2013
China	8.85	9.23	9.60	9.98
India	3.37	3.52	3.65	3.74
Japan	4.46	4.48	4.73	4.56
Korea	2.27	2.23	2.27	2.27

Source: IEA Oil Market Report, April 2013

Figure 3.14 Net Oil Imports: Asia 2012 to 2030



Source: EIA 2013 Annual Energy Outlook, Early Release

3.4 Markets Summary

The potential growth of western Canadian crude oil supplies exceeds the demand growth outlook in the whole of the North American market. The United States, given its geographic proximity will remain the primary market for western Canadian crude oil. In particular, Canadian producers need to extend their access to the Gulf Coast, which is the home of numerous complex refineries that account for over half of the total refining capacity in the nation. Besides the significant size of this market, most of these refineries are configured with the ability to process heavy western Canadian supplies. The development of rail infrastructure during the next two years will help to debottleneck transportation constraints and connect western Canadian crude oil to smaller niche markets such as eastern Canada, the U.S. East Coast and PADD V. On a global scale, the attention of producers is shifting away from the U.S. to Asian countries where demand is forecast to grow significantly. Canadian producers are aware of these changing market dynamics and continue to focus on developing all opportunities to extend or expand into new markets.

4 | CRUDE OIL PIPELINES

Crude oil in western Canada is essentially landlocked and will need additional transportation infrastructure to bring this steadily growing supply to markets. The transportation capacity available to deliver western Canadian crude oil supplies to markets is currently tight. This fact, combined with the phenomenal rise in U.S. production has contributed to the large price discounts on western Canadian crude oil relative to crude oil sold on world markets. There has been further development in a number of pipeline proposals and increased use of transportation by rail to connect growing Canadian production to markets. This chapter examines these proposals in more detail. Figure 4.1 shows major existing and proposed projects which provide take away capacity from the Western Canada Sedimentary Basin (WCSB) to key export markets including eastern Canada, Asia and the U.S. Gulf Coast.

Figure 4.1 Canadian and U.S. Crude Oil Pipelines - All Proposals

4.1 Existing Crude Oil Pipelines Exiting Western Canada

There are four major pipelines which move western Canadian crude out of the WCSB. The Enbridge Mainline and the Kinder Morgan Trans Mountain pipelines originate at Edmonton, Alberta. The Spectra Express and the TransCanada Keystone pipelines originate at Hardisty, Alberta. Together, these pipelines provide about 3.5 million b/d of capacity out of western Canada. In addition, a number of proposals have been announced that could increase this capacity during the next five years (Table 4.1). Currently capacity is tight. Operational and physical constraints can reduce available capacity to below stated capacity.

Table 4.1 Major Existing Crude Oil Pipelines and Proposals Exiting the WCSB

Pipeline	Capacity (thousand b/d)	Target In-Service
Enbridge Mainline	2,500	Operating since 1950
Enbridge Alberta Clipper Expansion	+120	Q3 2014
Enbridge Alberta Clipper Expansion	+230	Q1 2016
Kinder Morgan Trans Mountain	300	Operating since 1953
Trans Mountain Expansion	+590	Q4 2017
Spectra Express *downstream Platte operating since 1952	280	Operating since 1997*
TransCanada Keystone	591	Operating since 2010
TransCanada Keystone XL	+830	2015
Enbridge Northern Gateway	+525	Q4 2017
TransCanada Energy East	+525 to 850	Q4 2017
Total Existing Capacity		**3,671**
Total Proposed Capacity		**+2,820 to 3,145**

The following sections briefly summarize the existing pipeline projects. The proposed pipeline projects are discussed in the subsequent sections distinguished by the destination markets.

4.1.1 Enbridge Mainline

The Enbridge Mainline consists of numerous lines which deliver light and heavy crude oil as well as refined products from western Canada, Montana and North Dakota to markets in western Canada, the U.S. Midwest and Ontario. The Mainline connects with a number of pipelines in the U.S.: the Minnesota Pipeline at Clearbrook, Minnesota; Spearhead South and Flanagan South at Flanagan, Illinois; Chicap at Patoka, Illinois; Mustang at Chicago, Illinois and Toledo at Stockbridge, Michigan. The annual average receipt capacity from western Canada into the Mainline system is about 2.4 million b/d. However, the effective capacity is slightly less due to operational pressure restrictions on certain lines and physical constraints at terminals on the system.

There is also some U.S. production which enters the Enbridge Mainline and competes for capacity on the pipeline and in turn reduces the available capacity for crude oil from western Canada. The Enbridge North Dakota pipeline originates at Plentywood, Montana and ends at Clearbrook, Minnesota. It has a current capacity of 210,000 b/d which serves local markets and markets further east. Some U.S. crude oil production from the Bakken formation currently enters the Enbridge Mainline system at Clearbrook, Minnesota.

In response to significant growth in North Dakota and Montana, Enbridge is proposing an expansion of its North Dakota system. The project known as Sandpiper would include: a new 24-inch diameter pipeline from Beaver Lodge, North Dakota to Clearbrook, Minnesota with an incremental capacity of 225,000 b/d and a new 24-inch diameter pipeline from Clearbrook, Minnesota to Superior, Wisconsin with an initial capacity of 375,000 b/d. As part of the project scope, Enbridge would relocate the interconnection of the Enbridge North Dakota pipeline to the Lakehead System from Clearbrook, Minnesota. As a result, about 375,000 b/d of Bakken crude could enter the Enbridge Mainline at Superior, Wisconsin. The target in-service date for this project is January 2016.

The Enbridge Bakken Expansion project from Berthold, North Dakota to Cromer, Manitoba was put in service in March 2013. It provides 145,000 b/d of capacity to move U.S. Bakken crude into the Mainline destined for markets in the U.S. Midwest, Midcontinent and eastern Canada.

Enbridge Mainline Expansions - Alberta Clipper and Southern Access

Enbridge has planned two major expansions for its Mainline which will allow western Canadian crude to reach existing markets in the Midwest and Ontario and new markets in the U.S. Gulf Coast. The Alberta Clipper is a 36-inch diameter pipeline which extends from Hardisty, Alberta to Superior, Wisconsin. It is integrated with and forms part of the Enbridge Mainline.

The current capacity of the line is 450,000 b/d. Enbridge has received regulatory approval to expand the Alberta Clipper pipeline by 120,000 b/d. The target in-service date is Q3 2014. There are further plans to expand the line by an additional 230,000 b/d in Q1 2016. Upon completion of these expansions, the Alberta Clipper line will have reached its ultimate capacity of 800,000 b/d.

The Southern Access Pipeline is part of the Lakehead System (U.S. Mainline) and runs from Superior, Wisconsin to Flanagan, Illinois. The current capacity is 400,000 b/d. Enbridge has announced plans to expand the line by 160,000 b/d in Q3 2014. As part of its Light Oil Market Access program, Enbridge plans to increase capacity on the line by an additional 640,000 b/d in Q1 2015. Upon completion of these expansions, the Southern Access pipeline will have reached its ultimate capacity of 1.2 million b/d.

4.1.2 Spectra Express-Platte

In March 2013, Spectra Energy acquired the Express-Platte pipeline system from Kinder Morgan for $1.5 billion. 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. The pipeline capacity on Express is 280,000 b/d. In 2012, the average monthly throughput was 192,000 b/d versus 174,000 b/d in 2011. The ability to move crude on the Express pipeline is limited due to insufficient downstream capacity on the Platte pipeline.

The Platte Pipeline which is a 20-inch diameter pipeline moves crude oil from Western Canada, the Rockies (PADD IV), including the Bakken play area to refineries in the Midwest (PADD II). It runs from Casper, Wyoming to Wood River, Illinois. The capacity on the pipeline ranges from 164,000 b/d in Wyoming to 145,000 b/d in Illinois. In 2012, the average monthly deliveries into the Platte system were 216,000 b/d versus 193,000 b/d in 2011.

4.1.3 Kinder Morgan Trans Mountain

The Trans Mountain system is currently the only crude oil pipeline to Canada's west coast. It originates at Edmonton, Alberta, delivering both crude oil and petroleum products, to points in British Columbia, Washington, and the Westridge marine terminal. From the marine terminal located at Burnaby, British Columbia, crude oil is loaded onto vessels for offshore exports destined to California, the U.S. Gulf Coast and Asia.

The current capacity on the pipeline system is 300,000 b/d (assuming 20 per cent of the volumes being transported are heavy crude oil). Of the total capacity, 221,000 b/d is allocated to refineries with connections in British Columbia and Washington State and 79,000 b/d is allocated to the Westridge terminal for marine exports. Of the capacity designated to the marine terminal, 54,000 b/d or 68 per cent is underpinned by firm contracts and the remainder is available for spot shipments. Capacity on this pipeline has been in apportionment since late 2010.

4.1.4 TransCanada Keystone

The Keystone pipeline system originates at Hardisty, Alberta to Steele City, Nebraska. From this junction crude oil can be transported east to terminals in Wood River and Patoka, Illinois or south to Cushing, Oklahoma. The pipeline system can deliver a total of 590,000 b/d between the two routes. The pipeline started up in June 2010 while the Cushing extension came online in February 2011. About 530,000 b/d of capacity is contracted.

4.2 New Regional Infrastructure Projects in Western Canada

The major pipelines which move western Canadian crude out of the basin are investing significant capital in regional pipeline infrastructure to move incremental production to markets. The upstream expansions into Hardisty, Alberta could feed the Enbridge Mainline, Keystone, Keystone XL and the proposed TransCanadaEnergy East Pipeline into Eastern Canada.

4.2.1 Enbridge - Alberta Regional Pipeline

Enbridge - Edmonton to Hardisty

Enbridge is proposing to build a 36-inch diameter pipeline from Edmonton to Hardisty with a capacity of 800,000 b/d. The project includes five new tanks and terminal facilities at the Edmonton South terminal. The estimated cost is $1.8 billion. A regulatory application was submitted in December 2012 and the NEB has indicated that it would complete its review by April 2014, at the latest, in accordance with legislated time limits. The target in-service date is 2015.

4.2.2 TransCanada - Alberta Regional Pipelines

Heartland Pipeline and Terminal

TransCanada is proposing a 36-inch diameter pipeline from Heartland to Hardisty, Alberta the initiating point of its Keystone pipeline system with an ultimate capacity of 900,000 b/d. Heartland is an industrial area north of Edmonton, Alberta. At Hardisty, Alberta the pipeline would have connections to Keystone, Keystone XL and Energy East and Hardisty infrastructure. At the Heartland terminal, there will be up to 1.9 million barrels of tankage capacity available. The target in-service date for the Heartland pipeline is the second half of 2015.

Grand Rapids Pipeline Project

TransCanada announced a partnership with Phoenix Energy Holdings Limited (Phoenix) to develop the Grand Rapids Pipeline in northern Alberta. Each party will own 50 per cent of the proposed pipeline system. The project includes both a crude oil line and a diluent line between the producing area northwest of Fort McMurray and Heartland. The system could move up to 900,000 b/d of bitumen blend and up to 330,000 b/d of diluent. TransCanada anticipates filing a regulatory application in Q2 2013. The project has a target in-service date of 2017. TransCanada will operate the pipeline and Phoenix has entered into a long-term commitment to ship crude oil and diluent on the pipeline system.

4.3 Oil Pipelines to the U.S. Midwest

The U.S. Midwest is the largest market for western Canadian crude oil. The key market hubs in this region are located at Wood River and Patoka in Illinois and at Cushing, Oklahoma. Table 4.2 summarizes the pipelines which deliver Canadian crude oil to the Midwest.

4.3.1 Spectra Express-Platte

See Section 4.1.2.

4.3.2 TransCanada Keystone

See Section 4.1.4.

4.3.3 Southern Access Extension

Enbridge is proposing an extension to its Southern Access line which would run from Flanagan, Illinois to Patoka, Illinois. Enbridge will be holding a second open season in Q2 2013 to determine interest from shippers. The pipeline size and capacity will be determined following the open season. The target in-service date is Q2 2015.

4.3.4 Enbridge Line 6B

As part of Enbridge's Eastern Access Phase 2 program a segment of Line 6B will be replaced, from Ortonville, Michigan to the U.S. / Canada, border which would increase capacity from 240,000 b/d to 500,000 b/d in 2014. An expansion of the Line 6B between Chicago, Illinois and Stockbridge, Michigan from 500,000 b/d to 570,000 b/d will occur in 2016.

4.3.5 Minnesota Pipeline System

The Minnesota Pipeline system runs from Clearbrook, Minnesota to the Twin Cities. It is operated by Koch Pipeline Company. The pipeline delivers crude to the Northern Tier refinery in St. Paul Park and the Pine Bend refinery owned by Flint Hills in Rosemont. The system has a current capacity of 465,000 b/d that can be expanded to 650,000 b/d.

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

Pipeline	Originating Point	Destination	Status	Capacity (thousand b/d)
Minnesota Pipeline	Clearbrook, MN	Minnesota refineries	Operating	465
Enbridge Mainline	Superior, WI	various delivery points via L5, L6, L14/64,	Operating	1,476
Southern Access Southern Access Expansion Southern Access Expansion	Superior, WI	Flanagan, IL	Operating Proposed - Q3 2014 Proposed - Q1 2015	400 +160 +640
Enbridge Spearhead North Spearhead North Expansion	Flanagan, IL	Chicago, IL	Operating Proposed - Q4 2013	130 +105
Enbridge Spearhead North Twin	Flanagan, IL	Chicago, IL	Proposed - Q3 2015	+570
Enbridge Spearhead South	Flanagan, IL	Cushing, OK	Operating	193
Enbridge Flanagan South	Flanagan, IL	Cushing, OK	Proposed - Q3 2014	+585
Enbridge Mustang	Lockport, IL	Patoka, IL	Operating	100
Spectra Express-Platte	Guernsey, WY	Wood River, IL	Operating	145
TransCanada Keystone	Hardisty, AB to Steel City, NE	east to Patoka, IL / Wood River, IL or south to Cushing, OK	Operating	591

4.3.6 Koch Wood River

The Minnesota refineries receive western Canadian crude oil via connections to the Enbridge system as well as via deliveries from the Express-Platte pipeline system to Wood River, Illinois and a connection to the Wood River Pipeline. In January 2013, Koch Pipeline filed its tariff with the FERC advising the line is being purged and that nominations will no longer be accepted and that the tariff was to remain in effect until linefill was delivered and the tariff cancelled.

4.3.7 Spearhead

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 (commonly referred to as Line 62) or to Cushing, Oklahoma on Spearhead South (commonly referred to as Line 55). The current capacity on Spearhead North is 130,200 b/d. It will expanded by 104,800 b/d to 235,000 b/d by the end of 2013. As part of its Light Oil Market Access, Enbridge is considering a twin of the Spearhead North line along the existing pipeline which would provide an incremental capacity of 570,000 b/d by Q3 2015.

The current capacity on Spearhead South is 193,000 b/d. The proposed Flanagan South Pipeline Project discussed in section 4.4 would provide an additional 585,000 b/d along this pipeline corridor in 2014.

4.3.8 Enbridge Toledo Pipeline Expansion

The 16-inch diameter pipeline runs from Stockbridge, Michigan to Toledo, Ohio and has a capacity of 100,000 b/d. In May 2013, Enbridge completed construction of a new 20-inch diameter pipeline which added 80,000 b/d. A total capacity of 180,000 b/d is now available to satisfy refineries in Toledo, Ohio and Detroit, Michigan. This pipeline is commonly referred to as Line 7.

4.4 Oil Pipelines to the U.S. Gulf Coast

The Gulf Coast represents the most significant opportunity for market growth for heavy Canadian crude oil supplies in North America. Refineries in the region rely on domestic supply and imports primarily from Mexico, Saudi Arabia, and Venezuela to meet their requirements.

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

Pipeline	Originating Point	Destination	Status	Capacity (thousand b/d)
ExxonMobil Pegasus	Patoka, IL	Nederland, TX	Operating	96
Seaway Seaway Twin Line	Cushing, OK	Freeport, TX	Operating Proposed - Q1 2014	400 +450
TransCanada Keystone XL	Hardisty, AB	Steele City, NE	Proposed - 2015	
TransCanada Cushing Extension	*Steele City, NE*	*Cushing, OK*	*Operating*	
TransCanada Gulf Coast	*Cushing, OK*	*Nederland, TX*	*Proposed - Q4 2013* *Proposed - TBD*	+700 +130
Enbridge/Energy Transfer Eastern Gulf Crude Access	Patoka, IL	St, James, LA	Proposed - Mid 2015	+420 to 660

Given the significant increase in western Canadian and Bakken production and a lack of takeaway capacity at Cushing, Oklahoma, a number of pipeline projects are vying to bring supply from the Midwest to the U.S. Gulf Coast (Table 4.3).

4.4.1 ExxonMobil Pegasus

The ExxonMobil Pegasus Pipeline is one of only two pipelines that can currently 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. It runs from Patoka, Illinois to Nederland, Texas. Western Canadian crude can access the Pegasus pipeline via three routes: the Enbridge Mainline then onto the Mustang pipeline; the Express/ Platte system then onto the Woodpat Pipeline; and the Keystone Pipeline.

4.4.2 Enbridge Flanagan South

The Flanagan South Pipeline project is a 36-inch diameter pipeline that will be built along the existing Enbridge Spearhead South Pipeline. The pipeline which originates at Flanagan, Illinois and terminates at Cushing, Oklahoma would have an initial capacity of 585,000 b/d. The pipeline is currently under construction and has a target in-service date of July 2014. Enbridge has indicated that Flanagan South can be expanded up to 785,000 b/d through the addition of horse power.

4.4.3 Enbridge/Enterprise Seaway

The Seaway Pipeline is jointly owned by Enbridge Inc. and Enterprise Products Partners L.P. The pipeline flow was reversed in May 2012 to move crude oil from Cushing, Oklahoma to the U.S. Gulf Coast. The capacity on the pipeline gradually increased from 150,000 b/d to 400,000 b/d by January 2013, however, a lack of takeaway capacity at Jones Creek, located on the southern end of the pipeline, has limited the effective capacity at this time. The pipeline has experienced considerable levels of apportionment since coming into service.

Enbridge and Enterprise have secured sufficient commercial support to build a new twin line along the existing Seaway pipeline. The project scope includes laterals from Jones Creek to the Echo terminal that is connected to the Houston refinery complex and from Echo to the Port Arthur/Beaumont refinery complex.

The initial capacity on the new Seaway twin line is 450,000 b/d. Once completed, the Seaway pipeline system would have a total capacity of 850,000 b/d. The target in-service for the lateral from Jones Creek to Echo is late 2013 while target in-service date for the Seaway twin and lateral from Jones Creek to Port Arthur/Beaumont is Q1 2014.

4.4.4 Enbridge/Energy Transfer Eastern Gulf Crude Access

In February 2013, Enbridge and Energy Transfer announced a joint development for the Eastern Gulf Crude Access Pipeline Project. The project involves the conversion of a 30-inch diameter pipeline from natural gas service to crude oil service of certain segments of pipeline that are currently in operation as part of the natural gas system of Trunkline Gas Company, LLC. The pipeline would provide service from Patoka, Illinois to refining markets near Memphis, Tennessee, Baton Rouge and St. James in Louisiana. Western Canadian crude and Bakken crude can access the Patoka Hub via a number of existing and proposed pipelines including: Enbridge Southern Access Extension, TransCanada Keystone, Mustang, Ozark Pipeline/Woodpat Pipeline.

The pipeline capacity would range from 420,000 b/d to 660,000 b/d depending on the crude slate and level of commitments from shippers. An open season is anticipated in Q2 2013. Subject to regulatory approval, the 30-inch diameter pipeline would provide oil service in mid-2015.

4.4.5 TransCanada Keystone XL

In May 2012, TransCanada filed a new Presidential Permit application for Keystone XL for a proposed pipeline from Hardisty, Alberta to Steele City, Nebraska. In September 2012, TransCanada submitted an environmental report to the Nebraska Department of Environmental Quality. On January 23, 2013, the revised route in Nebraska was supported by the Governor of the state of Nebraska. A draft supplemental Environmental Impact Statement (EIS) was issued and a public comment period ended on April 22, 2013. The U.S. Department of State is continuing its review and will issue a final EIS. The next step in the regulatory process is the national interest determination. Should the project be approved, it would provide 830,000 b/d of capacity in 2015.

The Bakken Marketlink project from Baker, Montana, to Cushing, Oklahoma is designed to allow receipts of up to 100,000 b/d of crude oil from the Williston Basin, using capacity on the northern leg of Keystone XL. The Bakken Marketlink project is underpinned by 65,000 b/d of firm commitments.

4.4.6 TransCanada Gulf Coast

TransCanada Keystone announced that it was proceeding with its Gulf Coast Project regardless as to whether its Keystone XL project receives regulatory approval. The 36-inch diameter pipeline would provide capacity from Cushing, Oklahoma to Port Arthur and Houston, Texas. The initial capacity is 700,000 b/d which can be expanded to 830,000 b/d. Construction started in August 2012 and the target in-service date is late 2013.

The Keystone Pipeline System which includes Keystone, the Gulf Coast Project and the Keystone XL would provide 1.4 million b/d of capacity of which 1.1 million b/d is underpinned by long term contracts.

4.5 Oil Pipelines to the West Coast of Canada

The Kinder Morgan Trans Mountain pipeline is currently the only pipeline transporting crude oil from Alberta to the west coast. There is significant interest in building new pipeline capacity to the west coast. Once crude oil reaches the coast, it can be loaded off onto crude carriers to reach markets such as California, the U.S. Gulf Coast and Asia. Table 4.4 summarizes the Enbridge Northern Gateway and Kinder Morgan's pipeline proposals to the west coast.

Table 4.4 Summary of Crude Oil Pipelines to the West Coast of Canada

Pipeline	Originating Point	Destination	Status	Capacity (thousand b/d)
Kinder Morgan Trans Mountain	Edmonton , AB	Burnaby, BC	Operating	300
Kinder Morgan Trans Mountain Expansion			Proposed - Q4 2017	+590
Enbridge Northern Gateway	Bruderheim, AB	Kitimat, BC	Proposed - Q4 2017	+525

4.5.1 Enbridge Northern Gateway

The Northern Gateway Project includes a new 36-inch diameter crude oil pipeline with an initial capacity of 525,000 b/d from Bruderheim, Alberta (near Edmonton, Alberta) to Kitimat, British Columbia. The National Energy Board conducted extensive public hearings which concluded on May 1, 2013. Final oral arguments for the project will be heard in June 2013. The regulator will issue its recommendation on the project by December 29, 2013 as per the legislated time limits. A final decision will then be made by the Governor in Council. The target in-service date for the project is late 2017.

4.5.2 Kinder Morgan Trans Mountain Expansion

Kinder Morgan has proposed to expand its existing system (see section 4.1.3) with the addition of a new 36-inch diameter pipeline (twin pipeline to existing line), new pump stations, tanks and new tanker berths. If approved and constructed, the Trans Mountain system would then be comprised of two pipelines, the existing line (Line 1) and a new line (Line 2).

Line 1 could transport 350,000 b/d of refined petroleum products and light crude oil; heavy crude oil could also be moved but at a loss of capacity. The new Line 2 would have a capacity of 540,000 b/d for heavy crude oil and could also transport light crude oil, if necessary. The new pipeline and this configuration would add 590,000 b/d to the system for a total capacity of 890,000 b/d.

The expansion is underpinned by contracts totaling 707,500 b/d under 15 and 20-year commitments. The target in-service date is late 2017. In May 2013, Kinder Morgan received approval of its tolling methodology and principles for the proposed expansion on its system. The company plans on submitting a facilities application with the NEB in the fall of 2013.

4.6 Oil Pipelines to Eastern Canada

In 2012, refineries in Eastern Canada imported 680,000 b/d of crude from foreign sources. There is currently no pipeline infrastructure that connects western Canadian crude oil supply to markets in Atlantic Canada. This market represents an opportunity for western Canadian producers. Table 4.5 lists the pipeline proposals that could be conduits to this market

4.6.1 Enbridge Line 9 Reversal

The Enbridge Line 9 is a 30-inch diameter crude oil pipeline which runs from Montréal, Québec to Sarnia, Ontario. Line 9A refers to the portion from Sarnia, Ontario to North Westover, Ontario while 9B refers to the portion from North Westover, Ontario to Montréal, Québec. The pipeline has a current capacity of 240,000 b/d. In 2012, Enbridge received regulatory approval and is currently in the process of reversing the flow of Line 9A. The pipeline will move primarily light crude oil from Western Canada and the Bakken play. Of note, when Line 9 was first built, it moved crude from western Canada to Ontario and Montréal, Québec. The flow of the pipeline was reversed in 1999 and is expected to be re-reversed later this year.

In November 2012, Enbridge submitted a regulatory application to reverse the flow on Line 9B and increase the capacity by 60,000 b/d through the use of a drag reducing agent which does not require building additional facilities. The NEB will be holding a written hearing with oral final arguments in the summer of 2013. The target in-service date for Line 9B reversal is Q3 2014.

Table 4.5 Summary of Crude Oil Pipelines to Eastern Canada

Pipeline	Originating Point	Destination	Status	Capacity (thousand b/d)
Enbridge Line 9 re-Reversal	Sarnia, ON	Montréal, QC	Proposed	+300
9A	Sarnia, ON	North Westover, ON	Q3 2013	
9B	North Westover, ON	Montréal, QC	Q3 2014	
TransCanada Energy East	Hardisty, AB	Québec City, QC / St. John, NB	Proposed - Q4 2017	+525 to 850

4.6.2 TransCanada Energy East

TransCanada announced the Energy East Pipeline Project which includes the conversion of a natural gas pipeline to oil service and new pipeline segments to provide transportation service from Hardisty, Alberta to Québec City, Québec and St. John, New Brunswick. The proposed pipeline would have a capacity ranging from 525,000 to 850,000 b/d depending on market requirements. Currently there is a receipt point planned in southeast Saskatchewan that would enable Saskatchewan Bakken and other volumes to enter into the system. TransCanada is holding a binding open season which closes on June 17, 2013. The target in-service date for deliveries to Québec City and St. John is Q4 2017 and 2018, respectively.

4.7 Diluent Pipelines

Table 4.6 provides a summary of projects which aim to bring diluent supply which may be required to satisfying growing supply of heavy oil from western Canada.

4.7.1 Enbridge Southern Lights

The Southern Lights pipeline which runs from Manhattan, Illinois (near Chicago) to Edmonton, Alberta has been moving diluent since 2010. The current capacity of the pipeline is 180,000 b/d. In Q1 2013, Enbridge conducted an open season for 50,000 b/d of capacity available under firm contracts. In early May, Enbridge announced that the responses exceeded the amount of capacity available. As a result, Enbridge will conduct another open season later this year and will pursue an expansion of the diluent line from 180,000 b/d to 275,000 b/d.

4.7.2 Enbridge Northern Gateway Diluent

As part of its Northern Gateway Project, Enbridge is proposing a diluent pipeline that would run from Kitimat, British Columbia to Bruderheim, Alberta. The proposed capacity of the pipeline is 193,000 b/d. The Joint Review Panel (JRP) conducted extensive public hearings which concluded on May 1, 2013. Final arguments for the project will be heard in June 2013. The NEB will issue its recommendation on the project by December 29, 2013, at the latest, as per the legislated time limits.

4.7.3 TransCanada Grand Rapids Diluent

As part of its Grand Rapids Pipeline, TransCanada is proposing a diluent line from the Heartland region to Fort McMurray. The pipeline would have a capacity of 330,000 b/d in 2017. A regulatory application is expected to be filed with the provincial regulator in 2013.

4.7.4 Kinder Morgan Cochin Reversal Project

Kinder Morgan has secured firm transportation commitments for its Cochin Reversal Project. The project would allow movement of light condensate from Kankakee County, Illinois to existing terminal facilities near Fort Saskatchewan, Alberta. The project requires modifying the western leg of the Cochin pipeline to connect to the Explorer Pipeline Company located in Kankakee County and the reversal of product flow to move condensate northwest to Canada. The existing Cochin pipeline system is a 12-inch diameter multi-product pipeline with a current capacity of 70,000 b/d. The Cochin Reversal project will have a capacity of 95,000 b/d. During the open season, Kinder Morgan secured more than 100,000 b/d of commitments for a minimum 10-year term. The target in-service date for the project is July 2014 subject to regulatory approval.

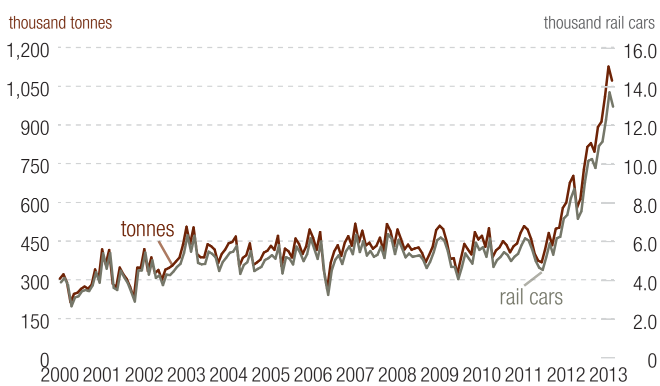
Table 4.6 Summary of Diluent Pipelines

Pipeline	Originating Point	Destination	Status	Capacity (thousand b/d)
Enbridge Southern Lights Southern Lights Expansion	Flanagan, IL	Edmonton, AB	Operating Proposed - TBD	180 +95
Enbridge Northern Gateway	Kitimat, BC	Bruderheim, AB	Proposed - Q4 2017	+193
Kinder Morgan Cochin Conversion	Kankakee County, IL	Fort Saskatchewan, AB	Proposed - Q3 2014	+95
TransCanada Grand Rapids	Heartland, AB	Fort McMurray, AB	Proposed - 2017	+330

4.8 Rail

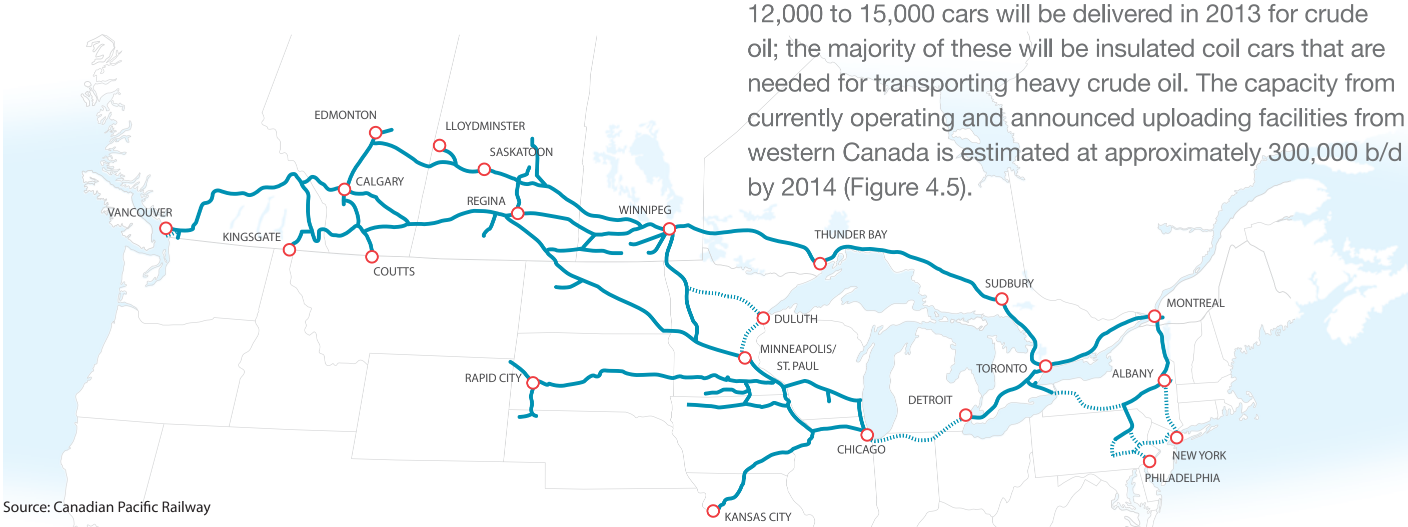
Transporting crude oil by rail has been growing quickly in the U.S. for a number of years but this trend is only now just emerging for crude oil originating from western Canada. Statistics Canada data reports 12,989 rail cars (1.1 million tonnes) were loaded in February 2013 transporting fuel oils and crude petroleum – a 60 per cent growth from February 2012 (Figure 4.2). According to the National Energy Board, in 2012, approximately 46,000 b/d of crude oil was exported to the U.S. by rail with most going to the U.S. Gulf Coast (48 per cent) and PADD I (43 per cent) with the remainder exported to PADD II and PADD V. This upward trend becomes more apparent when the fact that exports were as high as 120,000 b/d in December is considered. Experts forecast these exports to reach as much as 200,000 b/d by the end of 2013.

Figure 4.2 Canadian Fuel Oil and Crude Petroleum Moved by Rail: Car Loadings & Tonnage



Source: Statistics Canada

Figure 4.3 CP Rail Network



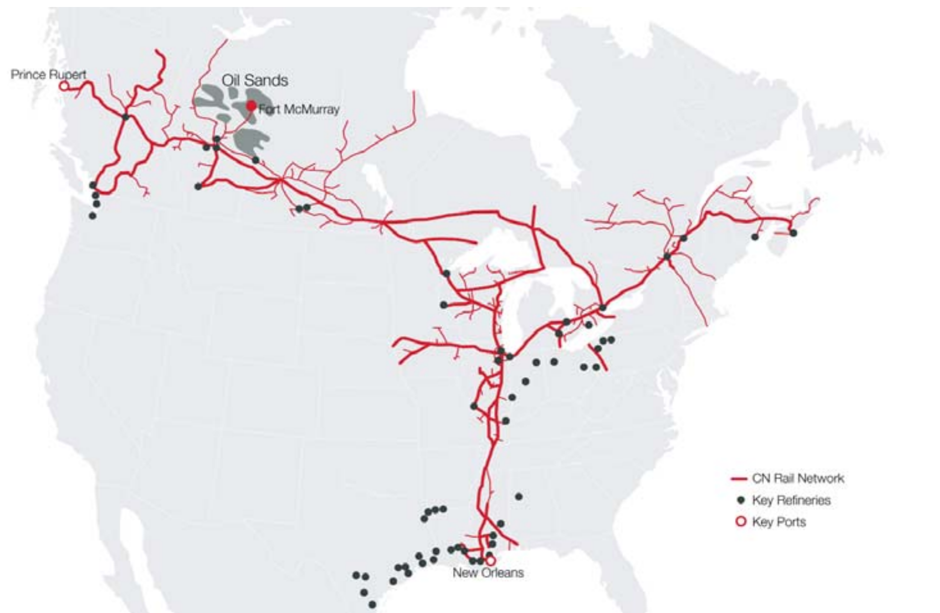
Source: Canadian Pacific Railway

Although rail tends to be a more expensive transportation option for crude oil it has a number of advantages over pipelines that help make it a viable alternative. In the long term, rail may even act as a complementary mode of transportation to pipelines as pipeline bottlenecks are alleviated. Extensive rail infrastructure is already in place, allowing producers the flexibility to reach essentially any market on the continent that has an unloading facility. Until pipelines are available, this means producers could reach higher priced markets using rail. In addition, movement of bitumen by rail requires significantly less diluent than pipelines, which can represent significant cost savings. Also, the sulphur content restriction on the crude oil transported by rail is less than when transported by pipelines. Refiners may also have greater certainty regarding the quality of crude oil received since there will be no mixing with other batches during transport, which is an event that often occurs during pipeline transportation.

Rail tracks are already in place to deliver crude oil to a number of markets from western Canada (Figure 4.3 and Figure 4.4). Therefore the major additional capital expenditures that are required are for terminal facilities needed for the uploading and offloading of crude oil. Larger, long-term terminal facilities with the capacity to load 100 car unit trains (65,000 to 70,000 barrels) that provide significant economies of scale can take from one to two years to be built. In contrast, start-up transloading facilities (which are smaller scale and limited to 2,000 to 20,000 barrels) can be put in place in only a few months.

The other main limitation on increasing current capacity is the availability of rail cars. There is about a two year waiting period from the time of ordering to the time of delivery. According to industry estimates, the backlog for tank rail car orders is close to 48,000. It is expected that that between 12,000 to 15,000 cars will be delivered in 2013 for crude oil; the majority of these will be insulated coil cars that are needed for transporting heavy crude oil. The capacity from currently operating and announced uploading facilities from western Canada is estimated at approximately 300,000 b/d by 2014 (Figure 4.5).

Figure 4.4 CN Rail Network



Source: Canadian National Railway

Rail Quick Facts

- Rail car capacity carrying light oil: 600 to 700 bbls
- Rail car capacity carrying heavy oil: 500 to 525 bbls
- RailBit and raw bitumen is transported in coiled and insulated rail cars to prevent solidifying in cold weather
- Unit train: 70 to 120 cars carrying only crude oil
- Manifest trains are mixed cargo trains delivering to different destinations
- Unit trains are used to carry one type of cargo from one location to another
- Economics for transport by rail improves with unit trains, however, unit train offloading capability is needed at destination

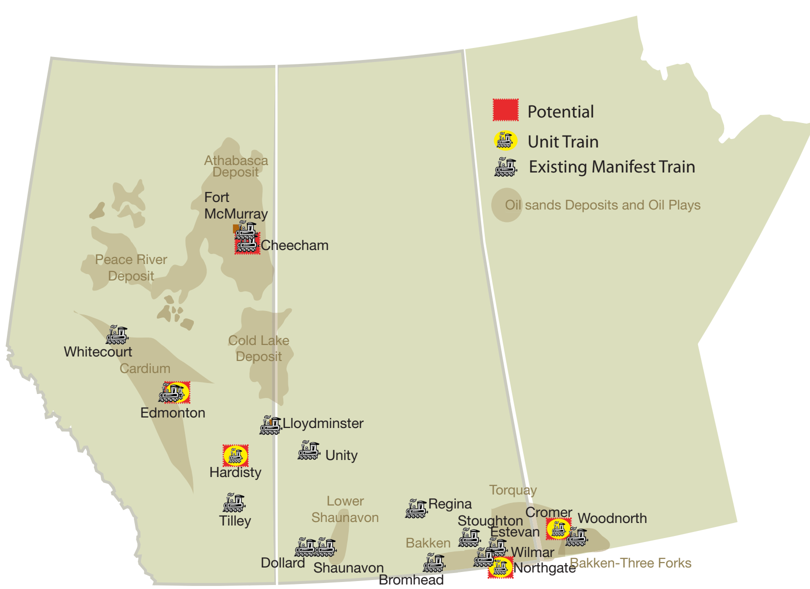
G-7 Generations' Alberta-Alaska Railway Concept

G7G Railway Corp. has introduced the concept of a new rail link from Fort McMurray to the Delta Junction in Alaska where oil would enter the Trans-Alaska (TAPS) pipeline system to reach tidewater at the Valdez marine terminal. The project propoents are in the process of seeking financial support to produce a feasibility study for this project.

Churchill Export Port

Churchill Gateway Development Corp. is looking to transform the Port of Churchill in northern Manitoba into a key export hub for western Canadian crude oil. It has traditionally been a key export point for western Canadian grain but is currently under utilized. Some challenges include the fact that the port is only ice-free from July to mid-October. The shipping season could be extended if shippers used icebreakers to accompany tankers but the added cost may be prohibitive. Target markets would include Europe, and refineries along the east coast of Canada and the U.S. The port is at the northern terminus of the Hudson Bay Railway owned by railroad holding company, OmniTRAX.

Figure 4.5 Rail Loading Terminals in Western Canada



Major Announced Rail Uploading Terminals in Western Canada

Operator	*Location*	*Capacity (thousand b/d)*	*Scheduled Startup*
Tundra	*Cromer, MB*	*Phase 1 - 30* *Phase 2 - 30*	*Q3 2013* *Q1 2014*
Keyera	*Cheecham, AB*	*32*	*Q3 2013*
Canexus	*Bruderheim, AB (near Edmonton, AB)*	*70*	*Q3 2013*
Gibson	*Hardisty, AB*	*60*	*2014*
Ceres Global	*Northgate, SK*	*70*	*Q4 2013*

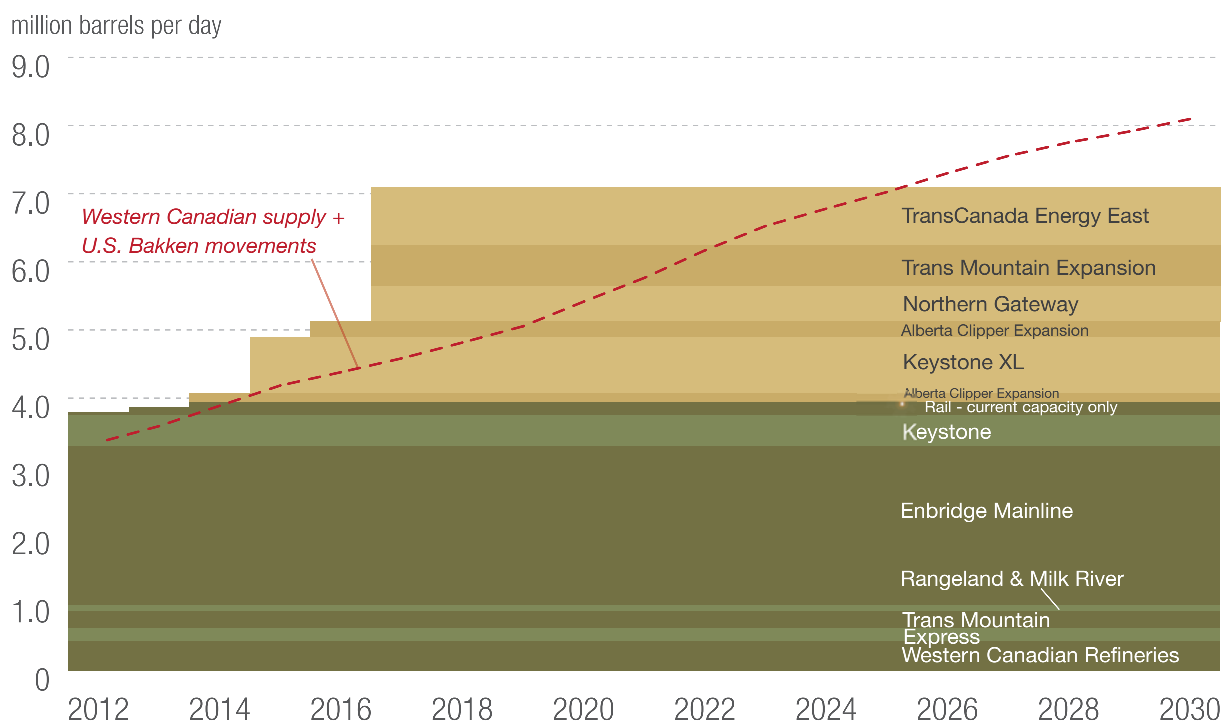
4.9 Pipeline Summary

The dynamics of the North American crude oil market are changing as growing western Canadian and Midcontinent 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 eastern Canadian and 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 transportation capacity exiting western Canada will be required by 2014.

Figure 4.6 WCSB Takeaway Capacity vs Supply Forecast



Capacity shown can be reduced by temporary operating and physical constraints.

GLOSSARY

API Gravity	A specific gravity scale developed by the American Petroleum Institute (API) for measuring the relative density or viscosity of various petroleum liquids.
Barrel	A standard oil barrel is approximately equal to 35 Imperial gallons (42 U.S. gallons) or approximately 159 litres.
Bitumen	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.
Coker	The processing unit in which bitumen is cracked into lighter fractions and withdrawn to start the conversion of bitumen into upgraded crude oil.
Condensate	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.
Crude oil (Conventional)	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.
Crude oil (heavy)	Crude oil is deemed, in this report, to be heavy crude oil if it has an API of 27° 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.
Crude oil (medium)	Crude oil is deemed, in this report, to be medium crude oil if it has an API greater than 27° but less than 30°. No differentiation is made between sweet and sour crude oil that falls in the medium category because medium crude oil is generally sour.
Crude oil (synthetic)	A mixture of hydrocarbons, similar to crude oil, derived by upgrading bitumen from the oil sands.
Density	The mass of matter per unit volume.
DilBit	Bitumen that has been reduced in viscosity through addition of a diluent (or solvent) such as condensate or naphtha.
Diluent	Lighter viscosity petroleum products that are used to dilute bitumen for transportation in pipelines.
Extraction	A process unique to the oil sands industry, in which bitumen is separated from their source (oil sands).
Feedstock	In this report, feedstock refers to the raw material supplied to a refinery or oil sands upgrader.
Integrated mining project	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.
***In Situ* recovery**	The process of recovering crude bitumen from oil sands by drilling.
Merchant upgrader	Processing facilities that are not linked to any specific extraction project but is designed to accept raw bitumen on a contract basis from producers.

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.
Open Season	A period of time designated by a pipeline company to determine shipper interest on a proposed project. Potential customers can indicate their interest/support by signing a transportation services agreement for capacity on the pipeline.
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.
Train (Manifest)	Manifest trains carry multiple cargoes and make multiple stops. These are small group or single car load.
Train (Unit)	Unit trains carry a single cargo and deliver a single shipment to one destination, lowering the cost and shortening the trip.
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

AL	Alabama
AK	Alaska
AZ	Arizona
AR	Arkansas
CA	California
CO	Colorado
CT	Connecticut
DE	Delaware
FL	Florida
GA	Georgia
ID	Idaho
IL	Illinois
IN	Indiana
IA	Iowa
KS	Kansas
KY	Kentucky
LA	Louisiana
ME	Maine
MD	Maryland
MA	Massachusetts
MI	Michigan
MN	Minnesota
MS	Mississippi
MO	Missouri
MT	Montana
NE	Nebraska
NV	Nevada
NH	New Hampshire
NJ	New Jersey
NM	New Mexico
NY	New York
NC	North Carolina
ND	North Dakota
OH	Ohio
OK	Oklahoma
OR	Oregon
PA	Pennsylvania
SC	South Carolina
SD	South Dakota
TN	Tennessee
TX	Texas
UT	Utah
VT	Vermont
VA	Virginia
VI	Virgin Islands
WA	Washington
WV	West Virginia
WI	Wisconsin
WY	Wyoming

APPENDIX B.1

CAPP Canadian Crude Oil Production Forecast 2013 – 2030

thousand barrels per day	Actual	*Forecast*																	
CONVENTIONAL	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Light & Medium																			
Alberta	408	447	516	543	553	558	565	574	581	588	598	611	626	636	645	657	671	687	703
B.C.	21	19	18	17	16	16	15	14	13	13	12	11	11	10	10	9	9	8	8
Saskatchewan [1,2]	211	201	191	195	176	179	183	186	189	193	198	203	209	215	221	227	233	238	244
Manitoba	50	50	50	50	47	45	44	43	42	41	41	40	39	38	37	37	36	35	34
N.W.T.	13	12	11	11	10	10	9	9	8	8	7	7	7	6	6	6	6	6	5
Ontario	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Atlantic Provinces [3]	197	218	192	225	221	217	276	284	247	226	222	199	193	174	149	136	114	97	87
W. Canada Light & Medium	**704**	**729**	**786**	**815**	**802**	**807**	**815**	**826**	**833**	**842**	**856**	**873**	**891**	**906**	**919**	**935**	**954**	**974**	**995**
E. Canada Light & Medium	**198**	**219**	**193**	**226**	**222**	**218**	**277**	**285**	**248**	**227**	**223**	**200**	**194**	**175**	**150**	**137**	**115**	**98**	**88**
Heavy																			
Alberta Conv. Heavy	148	151	152	149	146	143	140	137	135	132	129	127	124	122	119	117	115	112	110
Saskatchewan Conv. Heavy [1,2]	259	258	275	282	289	296	301	303	302	295	287	279	272	266	261	256	252	248	245
W. Canada Heavy	**406**	**408**	**428**	**431**	**435**	**439**	**441**	**440**	**437**	**427**	**416**	**406**	**396**	**388**	**380**	**373**	**367**	**361**	**355**
PENTANES/CONDENSATE	**139**	**135**	**130**	**127**	**124**	**121**	**119**	**116**	**113**	**111**	**109**	**107**	**105**	**103**	**101**	**99**	**97**	**96**	**94**
W. Canada Conventional (incl. condensates)	**1,246**	**1,270**	**1,343**	**1,373**	**1,361**	**1,368**	**1,375**	**1,382**	**1,384**	**1,380**	**1,381**	**1,385**	**1,392**	**1,396**	**1,400**	**1,408**	**1,418**	**1,431**	**1,445**
E. Canada Conventional (incl. condensates)	**202**	**221**	**193**	**226**	**222**	**218**	**277**	**285**	**248**	**227**	**223**	**200**	**194**	**175**	**150**	**137**	**115**	**98**	**88**
OIL SANDS (BITUMEN & UPGRADED CRUDE OIL)																			
Oil Sands Mining	811	906	976	984	1,007	1,044	1,095	1,123	1,227	1,337	1,457	1,572	1,598	1,645	1,689	1,687	1,679	1,683	1,684
Oil Sands *In situ*	986	1,079	1,182	1,296	1,436	1,546	1,671	1,823	1,996	2,160	2,344	2,501	2,664	2,808	2,977	3,158	3,304	3,407	3,524
TOTAL OIL SANDS	**1,797**	**1,985**	**2,158**	**2,280**	**2,443**	**2,590**	**2,766**	**2,946**	**3,223**	**3,497**	**3,801**	**4,074**	**4,262**	**4,454**	**4,666**	**4,845**	**4,983**	**5,090**	**5,208**
W. Canada Oil Production	*3,042*	*3,255*	*3,501*	*3,653*	*3,804*	*3,958*	*4,141*	*4,328*	*4,606*	*4,877*	*5,182*	*5,459*	*5,654*	*5,850*	*6,066*	*6,253*	*6,401*	*6,521*	*6,653*
E. Canada Oil Production	*202*	*221*	*193*	*226*	*222*	*218*	*277*	*285*	*248*	*227*	*223*	*200*	*194*	*175*	*150*	*137*	*115*	*98*	*88*
TOTAL CANADIAN OIL PRODUCTION	**3,245**	**3,476**	**3,694**	**3,879**	**4,026**	**4,176**	**4,418**	**4,613**	**4,854**	**5,104**	**5,405**	**5,659**	**5,848**	**6,025**	**6,216**	**6,390**	**6,516**	**6,619**	**6,741**
OIL SANDS RAW BITUMEN**																			
Oil Sands Mining	930	1,032	1,109	1,117	1,143	1,184	1,243	1,276	1,387	1,506	1,634	1,756	1,783	1,831	1,874	1,884	1,888	1,892	1,894
Oil Sands *In Situ*	996	1,116	1,216	1,332	1,471	1,579	1,701	1,853	2,027	2,191	2,378	2,536	2,699	2,844	3,014	3,195	3,343	3,446	3,563
TOTAL OIL SANDS	**1,926**	**2,148**	**2,325**	**2,449**	**2,614**	**2,763**	**2,944**	**3,129**	**3,414**	**3,696**	**4,012**	**4,292**	**4,482**	**4,674**	**4,888**	**5,080**	**5,231**	**5,338**	**5,457**

Notes:

1. *CAPP allocates Saskatchewan Area III Medium crude as heavy crude. Also 17% of Area IV is > 900 kg/m^3.*
2. *CAPP has revised from the June 2007 report historical light/heavy ratio for Saskatchewan starting in 2005.*
3. *Atlantic Canada production includes Newfoundland & Labrador production and negligible volumes from New Brunswick.*

*** 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.*

APPENDIX B.2 CAPP Western Canadian Crude Oil Supply Forecast 2013-2030

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

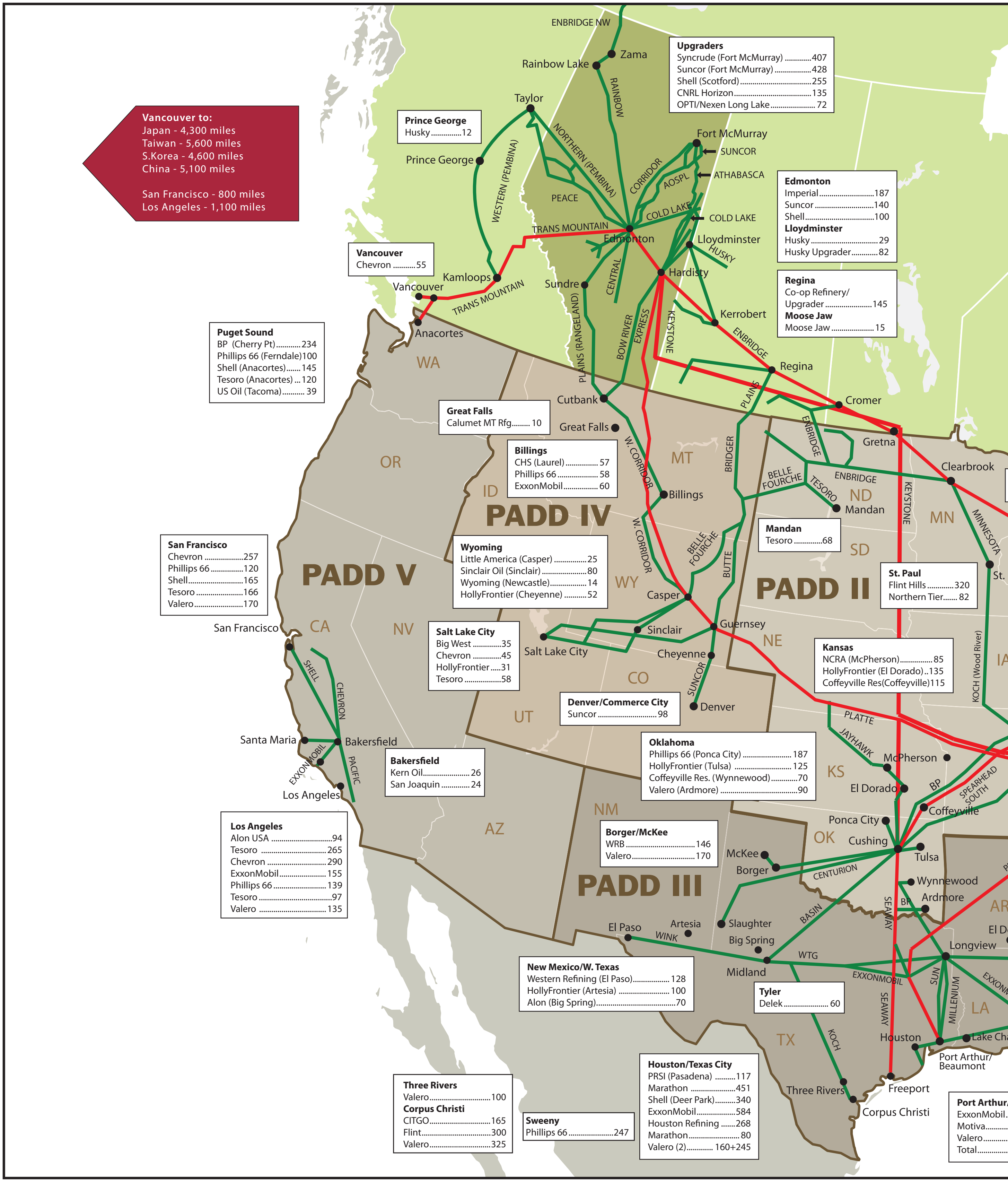
	Actual	Forecast																	
CONVENTIONAL	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Total Light and Medium	700	725	782	811	798	803	811	822	829	838	852	869	887	902	915	931	950	970	991
Net Conventional Heavy to Market	334	340	356	361	365	370	372	371	367	355	344	332	322	312	304	296	289	282	276
TOTAL CONVENTIONAL	**1,034**	**1,065**	**1,138**	**1,172**	**1,163**	**1,173**	**1,183**	**1,192**	**1,196**	**1,194**	**1,196**	**1,201**	**1,209**	**1,214**	**1,218**	**1,227**	**1,239**	**1,252**	**1,267**
OIL SANDS																			
Upgraded Light (Synthetic)[1]	752	841	855	857	834	807	788	777	775	771	770	763	755	752	752	753	754	755	761
Oil Sands Heavy [2]	1,413	1,532	1,744	1,907	2,133	2,353	2,593	2,835	3,194	3,548	3,952	4,312	4,565	4,808	5,080	5,323	5,508	5,655	5,817
TOTAL OIL SANDS AND UPGRADERS	**2,166**	**2,374**	**2,599**	**2,763**	**2,967**	**3,160**	**3,381**	**3,611**	**3,969**	**4,319**	**4,722**	**5,075**	**5,320**	**5,559**	**5,832**	**6,076**	**6,263**	**6,410**	**6,578**
Total Light Supply	1,452	1,566	1,637	1,668	1,632	1,610	1,600	1,598	1,604	1,610	1,622	1,631	1,642	1,653	1,667	1,685	1,704	1,726	1,752
Total Heavy Supply	1,747	1,872	2,100	2,267	2,498	2,722	2,965	3,205	3,561	3,904	4,296	4,644	4,887	5,120	5,383	5,618	5,797	5,937	6,093
WESTERN CANADA OIL SUPPLY	**3,199**	**3,438**	**3,738**	**3,935**	**4,130**	**4,333**	**4,564**	**4,804**	**5,165**	**5,513**	**5,918**	**6,276**	**6,529**	**6,773**	**7,051**	**7,303**	**7,501**	**7,662**	**7,846**

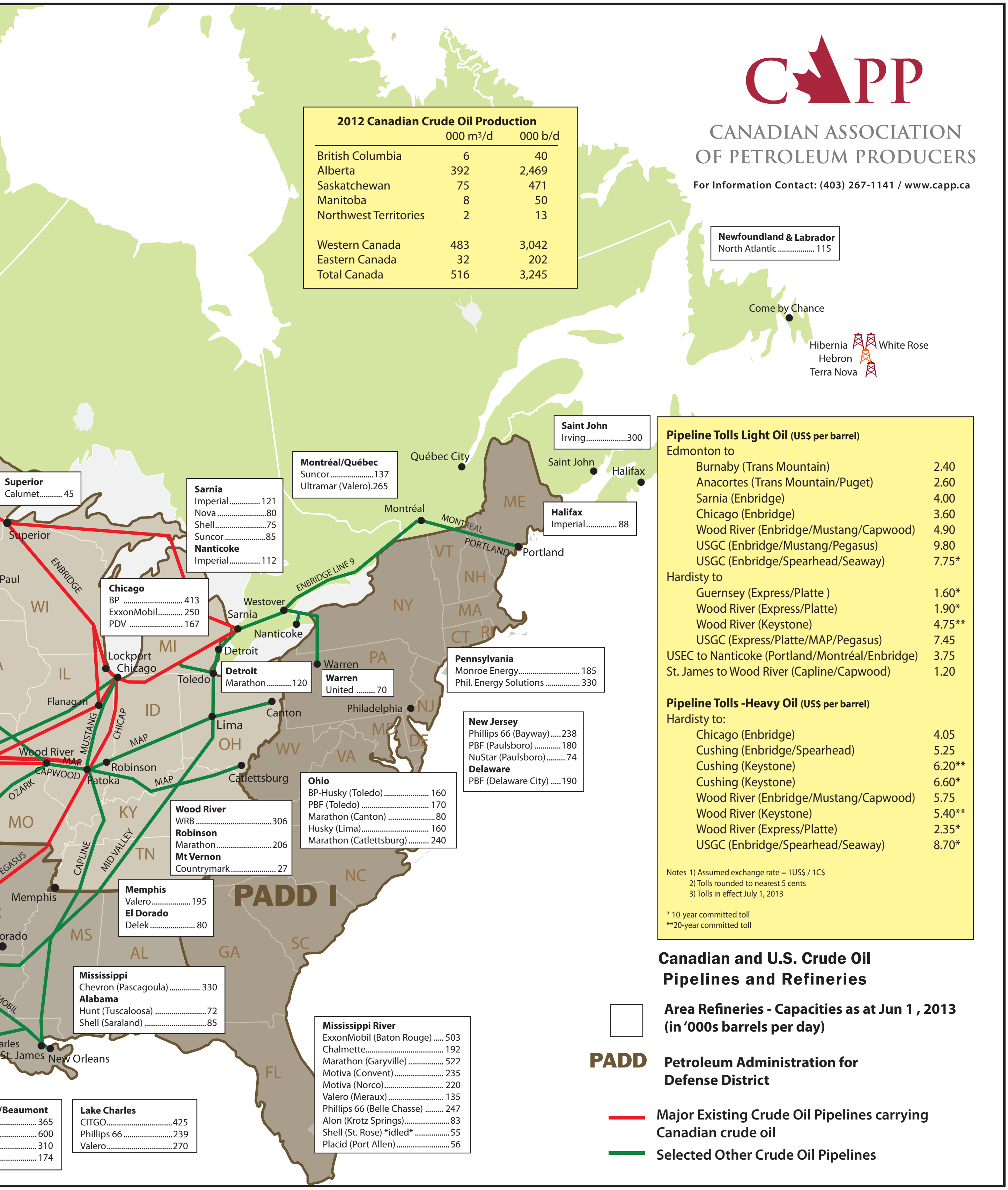
Notes:

1. *Includes upgraded conventional.*
2. *Includes: a) imported condensate b) manufactured diluent from upgraders and c) upgraded heavy volumes coming from upgraders.*

APPENDIX C

Crude Oil Pipelines and Refineries





2012 Canadian Crude Oil Production

	000 m³/d	000 b/d
British Columbia	6	40
Alberta	392	2,469
Saskatchewan	75	471
Manitoba	8	50
Northwest Territories	2	13
Western Canada	483	3,042
Eastern Canada	32	202
Total Canada	516	3,245

Pipeline Tolls Light Oil (US$ per barrel)

Edmonton to	
Burnaby (Trans Mountain)	2.40
Anacortes (Trans Mountain/Puget)	2.60
Sarnia (Enbridge)	4.00
Chicago (Enbridge)	3.60
Wood River (Enbridge/Mustang/Capwood)	4.90
USGC (Enbridge/Mustang/Pegasus)	9.80
USGC (Enbridge/Spearhead/Seaway)	7.75*
Hardisty to	
Guernsey (Express/Platte)	1.60*
Wood River (Express/Platte)	1.90*
Wood River (Keystone)	4.75**
USGC (Express/Platte/MAP/Pegasus)	7.45
USEC to Nanticoke (Portland/Montréal/Enbridge)	3.75
St. James to Wood River (Capline/Capwood)	1.20

Pipeline Tolls -Heavy Oil (US$ per barrel)

Hardisty to:	
Chicago (Enbridge)	4.05
Cushing (Enbridge/Spearhead)	5.25
Cushing (Keystone)	6.20**
Cushing (Keystone)	6.60*
Wood River (Enbridge/Mustang/Capwood)	5.75
Wood River (Keystone)	5.40**
Wood River (Express/Platte)	2.35*
USGC (Enbridge/Spearhead/Seaway)	8.70*

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CANADIAN ASSOCIATION
OF PETROLEUM PRODUCERS

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 about 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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Calgary Office:

2100, 350 - 7 Avenue SW
Calgary, Alberta, Canada
T2P 3N9

Phone: 403-267-1100
Fax: 403-261-4622

Ottawa Office:

1000, 275 Slater Street
Ottawa, Ontario, Canada
K1P 5H9

Phone: 613-288-2126
Fax: 613-236-4280

St. John's Office:

403, 235 Water Street
St. John's, Newfoundland and Labrador
Canada A1C 1B6

Phone: 709-724-4200
Fax: 709-724-4225

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