CAPP
CANADIAN ASSOCIATION
OF PETROLEUM PRODUCERS
Canada's Oil and Natural Gas Producers

Crude Oil

Forecast, Markets & Transportation

June 2014

On Cover:
Top Left: Crude by Rail tank car- photo courtesy of Altex Energy
Top Right: Prince George refinery - photo courtesy of Husky Energy
Bottom Left: TransCanada Keystone construction - photo courtesy of TransCanada
Bottom: Cenovus *in situ* project

EXECUTIVE SUMMARY

Canadian crude oil production is expected to grow over the long-term to 6.4 million b/d by 2030. These supplies will meet the demand of markets located throughout North America and beyond. The recent uncertainty regarding the timing of some transportation infrastructure projects has opened the door for several alternatives, including the transport of crude oil by rail, which is rising and adapting to meet market needs.

The key points of this year's outlook are:

- Canadian oil production growth is driven by the oil sands, which is expected to grow 2.5 times from current production of 1.9 million b/d to 4.8 million b/d by 2030. Total conventional production, inclusive of condensate, grows slightly and will contribute 1.5 million b/d to total production. This is a reversal of the declining trend in condensate production previously forecast.
- Multiple markets are expressing growing interest in crude oil from Western Canada. There are opportunities to replace foreign crude oil imports in Canada and the United States at refineries along the East Coast, West Coast and Gulf Coast. Demand from global markets, such as Asia and Europe, could be met but requires access to tidewater. There are projects in the regulatory process and others being considered to achieve this.
- Longer timelines for new pipeline capacity have led to a developing role for rail in the crude oil transportation network as the use of this mode is increasing overall crude oil transportation capacity.

Crude Oil Production and Supply

With new stability in conventional crude oil production and almost 3 million b/d in oil sands growth, Canadian crude oil production grows to 6.4 million b/d in 2030.

Canadian Crude Oil Production

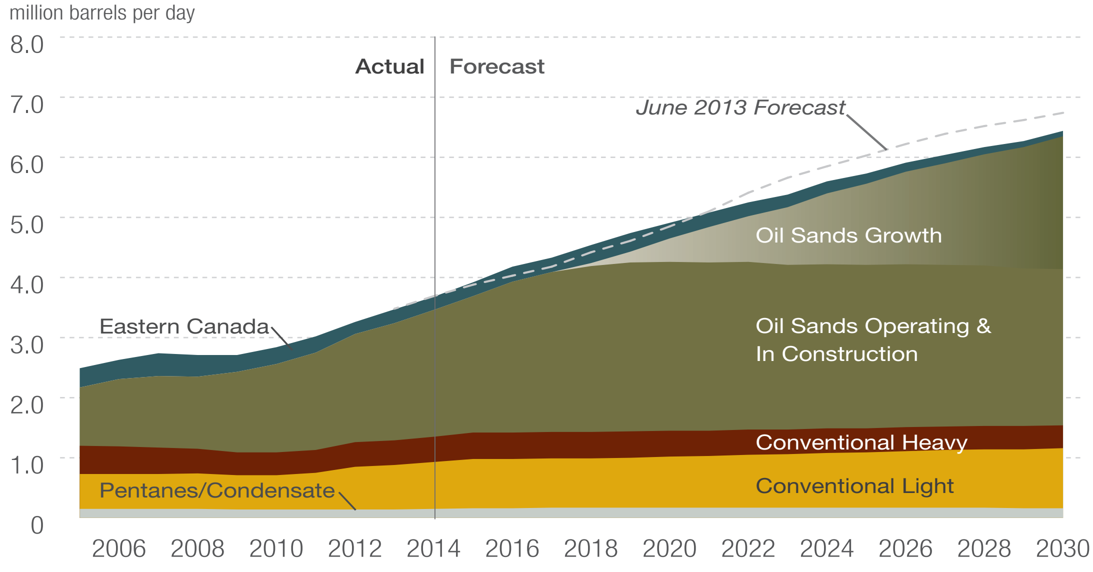
million b/d	2013	2015	2020	2025	2030
Total* Canadian (including oil sands)	3.5	3.9	4.9	5.7	6.4
Eastern Canada	0.2	0.2	0.3	0.2	0.1
Western Canada	3.2	3.7	4.6	5.6	6.4
Conventional (including condensate)	1.3	1.4	1.5	1.5	1.5
Oil sands	1.9	2.3	3.2	4.1	4.8

*Totals may not add up due to rounding.

Canadian crude oil production is expected to grow by an average of 4 per cent annually until 2030. Western Canadian production reaches 6.4 million b/d by the end of the outlook. Production in Eastern Canada is stable in the near term but declines gradually by 2030.

Compared to CAPP's 2013 forecast, western Canadian production is similar through 2020 and lower by about 300,000 b/d in 2030. This is the overall net effect of a higher conventional and a lower oil sands forecast. Conventional production is 100,000 b/d higher primarily due to more condensate resulting from the industry's increased focus on drilling in liquids-rich plays. The oil sands forecast is 400,000 b/d lower. A number of factors contribute to this variation including cost competitiveness and delays in project schedules.

Canadian Oil Sands & Conventional Production



Conventional Oil

Conventional production in Western Canada is currently 1.3 million b/d and is expected to grow to almost 1.5 million b/d by 2020. This growth has resulted from the continuing use of horizontal and multi-stage fracturing drilling techniques. In addition, increased drilling in liquids-rich natural gas plays such as the Montney and emerging plays like the Duvernay has reversed the declining trend in condensate production, which was previously forecast to fall to 94,000 b/d by 2030. In this latest forecast, condensate production accounts for almost 170,000 b/d, on average, for the forecast period.

Oil Sands

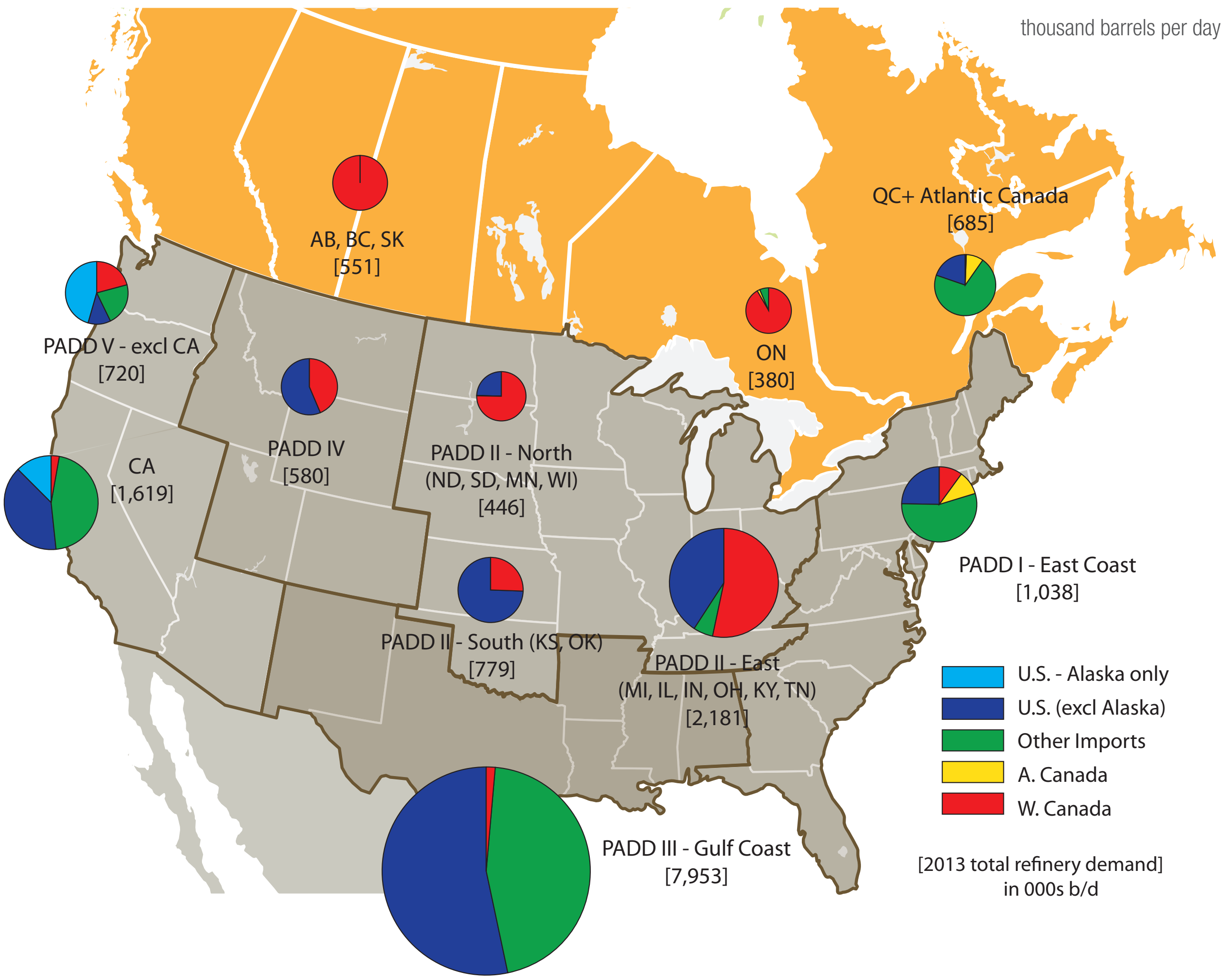
The vast majority of Canada's crude oil reserves reside in the oil sands so it is natural for this resource to be the primary driver for future overall growth. The 2014 outlook for oil sands is for an average annual growth of 170,000 b/d through to 2030.

In 2013, 1.9 million b/d were produced from the oil sands of which 850,000 b/d was from mining and 1.1 million b/d from *in situ* projects. Looking ahead to 2030, mining production is forecast to increase to 1.6 million b/d and *in situ* production is forecast to grow to 3.2 million b/d. Compared to CAPP's 2013 forecast, this is 87,000 b/d lower for mining and 312,000 b/d lower for *in situ.* Some projects were delayed beyond the current forecast period as a result of individual company decisions related to cost competitiveness and capital availability. These impacts are evident near the end of the forecast period.

Eastern Canada

In 2013, Eastern Canada accounted for about 7 per cent, or 232,000 b/d of total Canadian crude oil production. The Hebron project is scheduled to startup in 2017 and provide new volumes. By 2030, production is forecast is to gradually decline to around 90,000 b/d but this could be higher than forecast given the announcement of three recent discoveries in the Flemish Pass Basin. The largest new prospect is Bay du Nord, which is estimated to hold between 300 and 600 million barrels of recoverable oil.

2013 Canada and U.S. Crude Oil Demand by Market Region



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

Crude Oil Markets

Canada continues to fuel growing international markets.

With 1.7 million b/d of additional crude oil supplies from Western Canada expected to be available by 2020, Canadian producers are seeking to expand their reach to Eastern Canada, the West Coast and U.S. Gulf Coast markets. Growing production from U.S. tight light oil plays has resulted in U.S. domestic supplies replacing almost all the foreign light oil imports in the Gulf Coast and a large portion in the East Coast. However, significant markets for growing heavy oil supplies are still available in the U.S. Midwest, Gulf Coast and elsewhere globally.

Eastern Canada

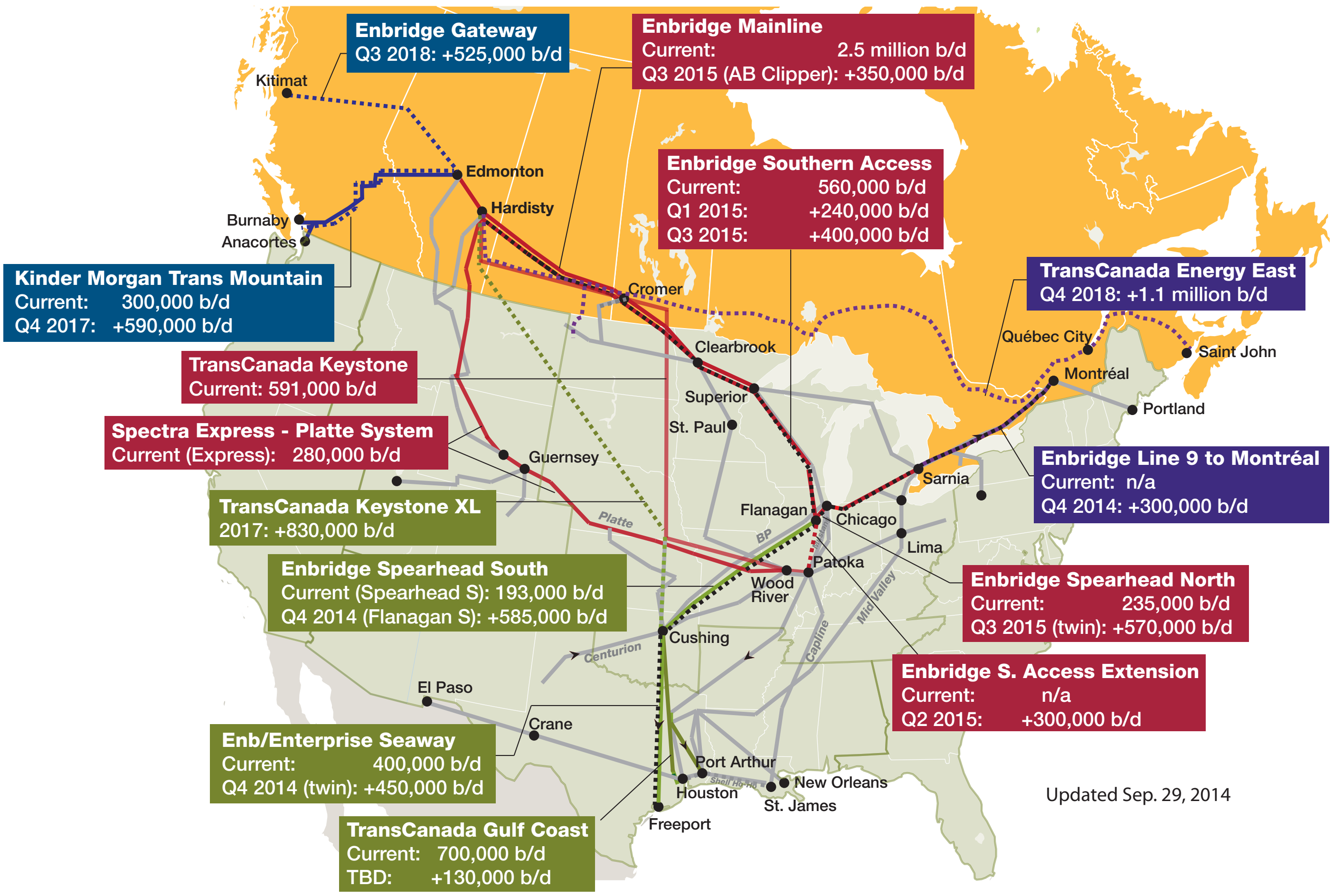
Refineries in Québec and Atlantic Canada currently import 90 per cent of their requirements. This translates to a potential 640,000 b/d domestic market opportunity for Canadian supplies, particularly conventional light and synthetic crude oil. Refineries in Ontario have already shifted their main source of crude oil feedstock to Western Canada.

United States

Refineries in the U.S. Gulf Coast processed almost 8 million b/d of crude oil in 2013, including over 2 million b/d of foreign heavy oil imports. Canadian producers could displace some of these imported volumes and are forecast to supply at least 680,000 b/d to this market by 2020, up from the 120,000 b/d that is currently supplied.

The Midwest will remain Canada's largest export market. In 2013, Canadian producers supplied 1.7 million b/d to this market. A number of refinery conversion projects for processing heavy crude oil have been completed in the last two years and are anticipated to increase demand in the region by 465,000 b/d to reach 2.2 million b/d by 2020.

Canadian & U.S. Crude Oil Pipelines and Proposals



Refineries in Washington and California need to replace their declining traditional sources of supply. These refineries are expected to double current demand for western Canadian crude oil of 198,000 b/d to 392,000 b/d. Similarly, demand from East Coast refineries could double from 2013 demand of 104,000 b/d to almost 200,000 b/d. Refineries on both the East and West Coasts in the U.S. are making investments in rail infrastructure in order to gain access to growing U.S. domestic and western Canadian supplies.

World

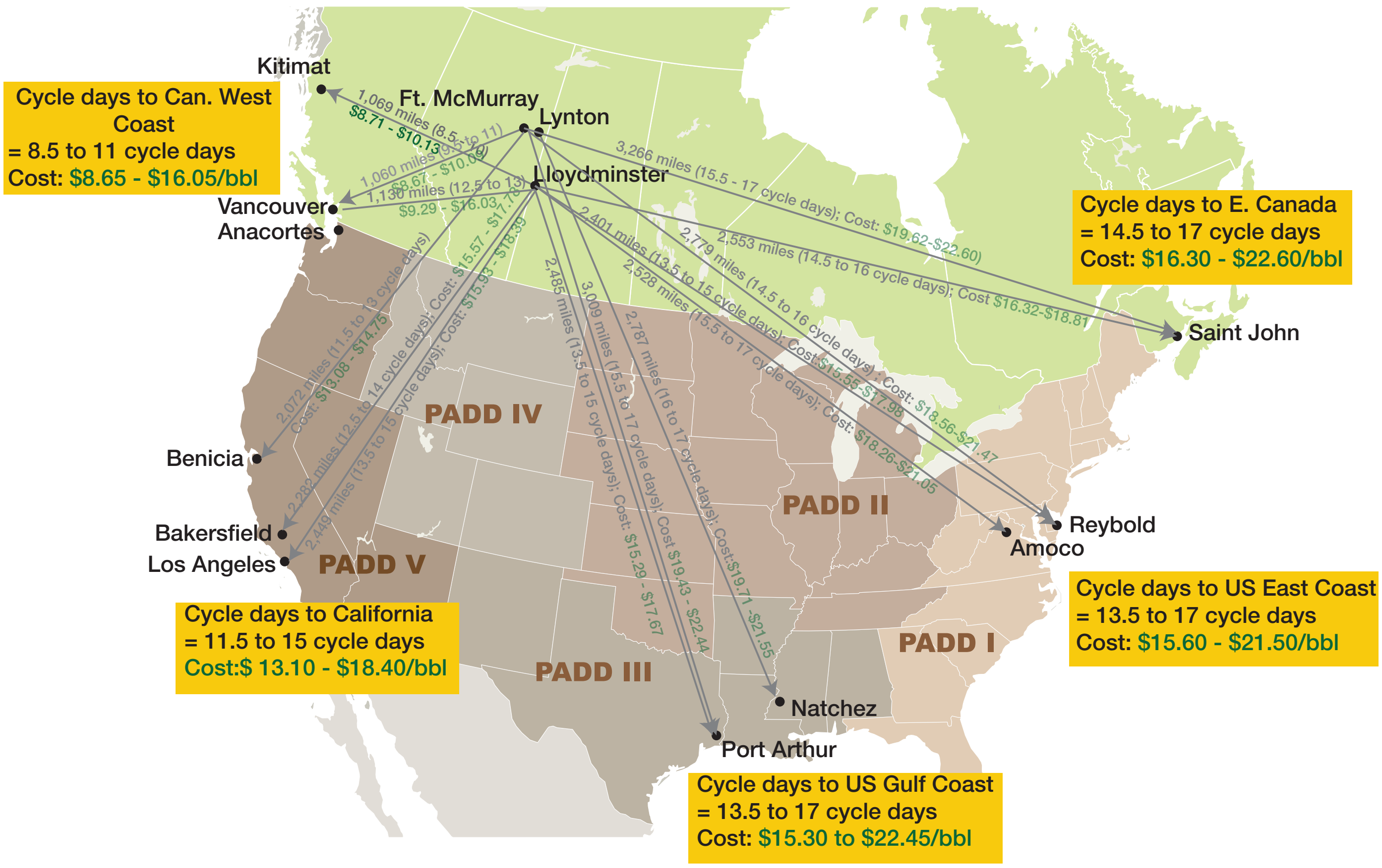
The crude oil producing regions of western Canada have limited access to tidewater and to global crude oil markets. However, there is strong interest in Asia and growing interest from Europe for Canadian crude oil. In particular, China and India are obvious potential markets as they currently have the fastest growing demand for oil in the world. According to the U.S. Energy Information Administration (EIA), combined oil imports from China and India are forecast to increase by 8.0 million b/d; going from 9.7 million b/d in 2013 to 17.7 million b/d by 2030.

Crude Oil Transportation

Pipelines projects to the East, West and South are being developed to access new markets while rail is becoming a growing alternative to supplement the existing, expanding pipeline network.

The growing supply of crude oil from Western Canada is filling the existing pipeline capacity and protracted timelines for regulatory approvals combined with other uncertainties have affected the evolution of the transportation network. Other forms of transport, such as railways, barges, and tankers are quickly becoming additional means to distribute increasing volumes to markets throughout the U.S., Eastern Canada and offshore.

Rail Cycle Times & Estimated Cost to Markets



**All rates are estimates only. Actual rates could vary depending on the density of the crude which limits the volume per carload; weather and logistical factors that could increase cycle times. Trucking costs vary depending on density of crude and distance from loading/unloading terminal.*

Data source: Keystone XL Final Supplemental Environmental Impact Statement

Pipelines remain the primary mode of transportation for crude oil due to their relatively low cost and ability to continuously move large volumes to key markets. There are a number of pipeline projects being proposed (see figure on page iii) that could deliver large volumes of Canadian crude oil to the East Coast, West Coast, U.S. Gulf Coast and offshore markets. However, the timing and order for the various projects continues to have some uncertainty.

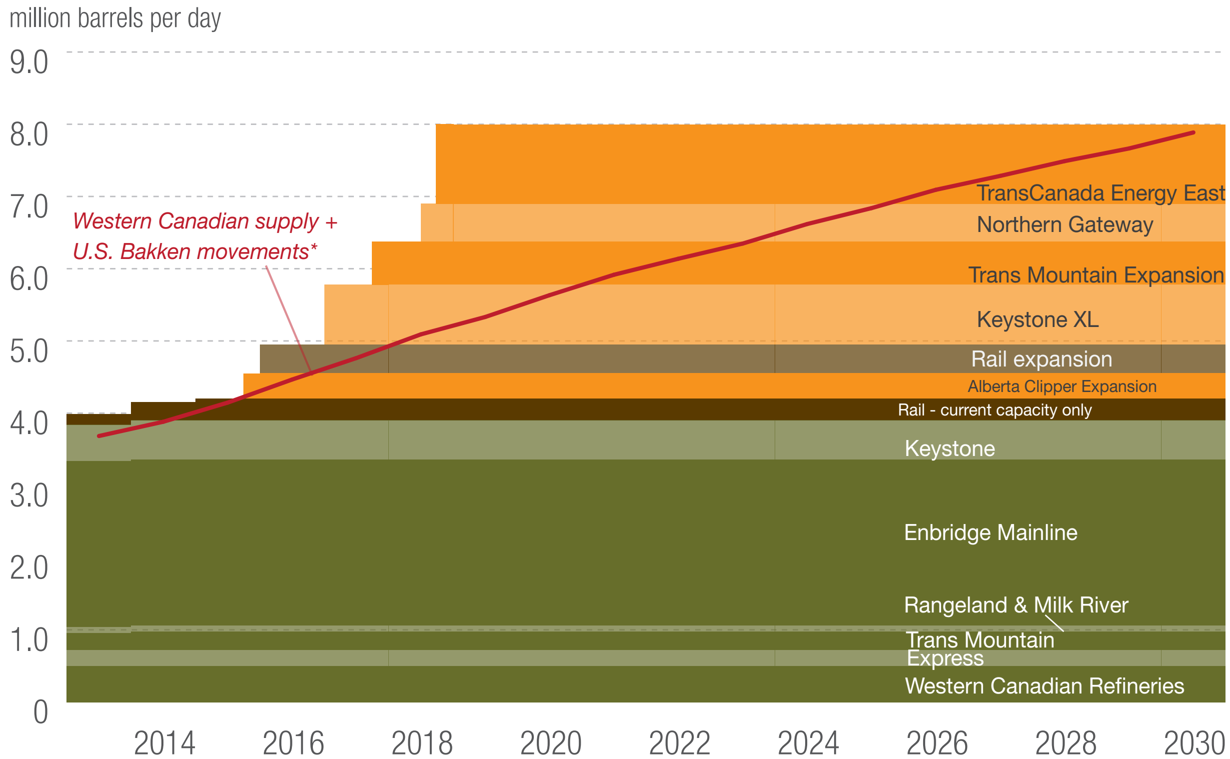
As a result, crude oil producers are increasingly using rail as an alternative means of transportation. The existing rail nework enable this mode of transportation to reach all the desired markets once capital investments in both loading and unloading facilities are made. A train loading facility can be constructed in about one year. The flexibility of rail to deliver to multiple destinations is a key component for its long-term viability.

Based on publicly reported supply contracts associated with uploading terminals located in Western Canada, CAPP estimates that about 700,000 b/d of crude oil could potentially be transported to markets by rail in 2016.

The figure below summarizes the existing and proposed takeaway capacity from the Western Canada Sedimentary Basin versus forecasted supply.

Since last year, some pipeline projects have been delayed but other alternatives are being developed and used. The figure shows that there is tight capacity in the first few years. In addition, the capacity provided by all the proposals will be needed by 2030 to meet the forecast growth.

WCSB Takeaway Capacity vs. Supply Forecast



*Refers to the portion of U.S. Bakken production that is also transported on the Canadian pipeline network.
Capacity shown can be reduced by temporary operating and physical constraints.

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1 | INTRODUCTION

Each year CAPP publishes its long-term outlook for Canadian crude oil production. Since 2007, this outlook has been provided in conjunction with an examination of the potential demand in various markets, as well as an update on the transportation infrastructure that is both currently available and proposed to serve these markets. As such, CAPP's annual *Crude Oil Forecast, Markets & Transportation* publication provides a valuable reference document for the industry, governments and the general public.

The report is intended to help develop a common understanding regarding the growth in Canadian crude oil supply. CAPP's long-term crude oil forecast is based on the amalgamated results of the producers' latest views on their individual oil sands projects while the market demand forecast reflects an unadjusted survey of North American refiners' future demand for western Canadian crude oil.

Canadian crude oil production is expected to grow steadily to 2030 driven primarily by production from oil sands resources. The oil sands represent over 97 per cent of Canada's crude oil reserves and is the main source for future growth. CAPP's estimate of industry capital spending on oil sands development is $29 billion for 2014, which is $2 billion higher than the estimated expenditure in 2013. Conventional production grows slightly through the forecast, which offsets some of the declines in production from offshore Eastern Canada after 2020.

1.1 Production and Supply Forecast Methodology

The oil sands component of the forecast is based on 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.

CAPP does not forecast crude oil prices. Producers responded to the survey using 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 for each project by phase;

b) upgraded light crude oil production; and

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

The survey results were then adjusted or "risked" accordingly 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.

The conventional component of the forecast is undertaken at a provincial level and was developed through CAPP's internal analysis of historical trends, expected drilling activity, recent announcements, as well as discussions with industry stakeholders and government agencies.

The Saskatchewan forecast is further supported by the data from CAPP's survey of the oil producers in the province regarding their annual drilling outlook by well type (horizontal or vertical), as well as their anticipated initial production rates and declines.

1.2 Market Demand Outlook Methodology

CAPP did not make any risk adjustments to the data submitted by refiners beyond checking it for potential errors. Certain assumptions were also made based on discussions with refiners and the review of publicly available information. Where possible, EIA data was used to complete gaps in the survey data for actual demand in 2013 for each region of the U.S.

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

1. Conventional Light Sweet (greater than 27° API and less than or equal to 0.5% sulphur) including condensates and pentanes plus;
2. Heavy (equal to or less than 27° API) including conventional heavy, synthetic sour and crude oil blends such as DilBit, SynBit and DilSynBit;
3. Conventional Medium Sour (greater than 27° API and greater than 0.5% sulphur); and
4. Light Sweet Synthetic

For the purposes of the historical data presented in the source of supply pie charts in this section of the report, the following crude types and definitions apply:

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

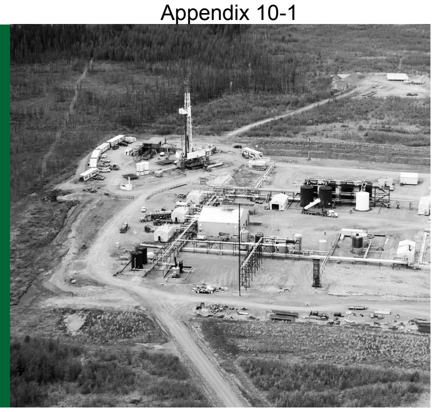
No differentiation is made between sweet and sour crude oil that falls into the heavy category because heavy crude oil is generally assumed to be sour.

1.3 Transportation Outlook Methodology

CAPP's forecast of rail movements from Western Canada was developed based in part on a review of supply contract volumes attributed to individual rail loading facilities located in Western Canada.

CAPP's production forecast is not constrained by a 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 if these transportation projects fail to materialize in the time frame they are currently envisaged.

2 | CRUDE OIL PRODUCTION AND SUPPLY FORECAST



Beyond being a feedstock for transportation fuels, crude oil is used in Canada and around the world in the manufacture of many everyday items that improve our quality of life. These include heating fuels, plastics, petrochemicals and even pharmaceuticals. Canada holds 173 billion barrels of proven crude oil reserves, which according to the Oil & Gas Journal, are the world's third largest reserves after Venezuela and Saudi Arabia. The province of Alberta resides on top of the oil sands, which holds 167 billion barrels of these reserves. The strategic development of these resources is important to the industry and a key element to economic growth and achieving long-term prosperity for Canada. It provides for security of supply, creates jobs, and promotes innovation.

Technology required to access the bitumen carbonates of Northern Alberta, is under early development. Companies conducting tests in the region to commercialize these carbonates, claim that the Grosmont carbonates alone could hold more than 400 billion barrels of in place bitumen. Thus successful development of these technologies could further dramatically increase the size of Canada's crude oil resource base.

2.1 Canadian Crude Oil Production

In 2013, Canada produced 3.5 million b/d of crude oil, an increase of 225,000 b/d or 7 per cent over 2012 levels. This production, most of which comes from Western Canada, is expected to continue to grow steadily throughout the forecast period. Western Canada produced 3.2 million b/d in total, of which 1.9 million b/d came from the oil sands and 1.3 million b/d came from conventional resources. About 232,000 b/d of Canada's production originated in Eastern Canada.

Table 2.1 shows the forecast for total Canadian production and its breakdown between Eastern and Western Canada. Figure 2.1 shows the total Canadian production forecast. Conventional production from Western Canada is expected to grow slightly throughout the forecast to over 1.5 million b/d. Oil sands production will be the main driver of the overall increase in production as it is expected to increase by 2.5 times from 2013 levels of 1.9 million b/d to reach 4.8 million b/d by 2030.

Table 2.1 Canadian Crude Oil Production

million b/d	2013	2015	2020	2025	2030
Total* Canadian (including oil sands)	3.47	3.91	4.91	5.74	6.44
Eastern Canada	0.23	0.23	0.26	0.17	0.09
Western Canada	3.24	3.68	4.65	5.57	6.35

*Totals may not add up due to rounding.

2.2 Eastern Canadian Crude Oil Production

Atlantic Canada is the primary source of Eastern Canada's crude oil production. Some minor volumes have been produced from Ontario and New Brunswick but the oil resources essentially reside in offshore oil projects located off the shores of Newfoundland and Labrador. The three offshore oil fields currently in production are: Hibernia, Terra Nova and White Rose. The overall rate of decline from these facilities has slowed as a result of continued drilling at satellite fields associated with these projects (e.g. Hibernia South Extension, North Amethyst and West White Rose). First oil from Hebron, the fourth major project, is expected around the end of 2017.

CAPP's forecast includes existing projects, planned satellites and the Hebron project under construction. In 2013, production increased to 232,000 b/d, up 15 per cent from 2012 levels. This 30,000 b/d increase was reflective of a return to normal operations after significant maintenance shutdowns at all three projects during 2012. Overall, there is little change compared to CAPP's 2013 forecast.

Future production could be higher than forecast given the announcement of three recent discoveries in the Flemish Pass Basin. The largest new prospect is the Bay du Nord, which is estimated to hold between 300 and 600 million barrels of recoverable oil. The Mizzen discovery is estimated to hold 100 to 200 million barrels while the Harpoon discovery is still under evaluation.

2.3 Western Canadian Crude Oil Production

Western Canadian crude oil production comes from both conventional and oil sands sources. Production from both sources is expected to contribute significantly to the forecast outlook (Table 2.2). The oil sands are essentially found in the province of Alberta, while conventional resources underlie Alberta, northeast British Columbia, Saskatchewan and parts of Manitoba and the Northwest Territories. Please refer to Appendix B.1 for detailed production data.

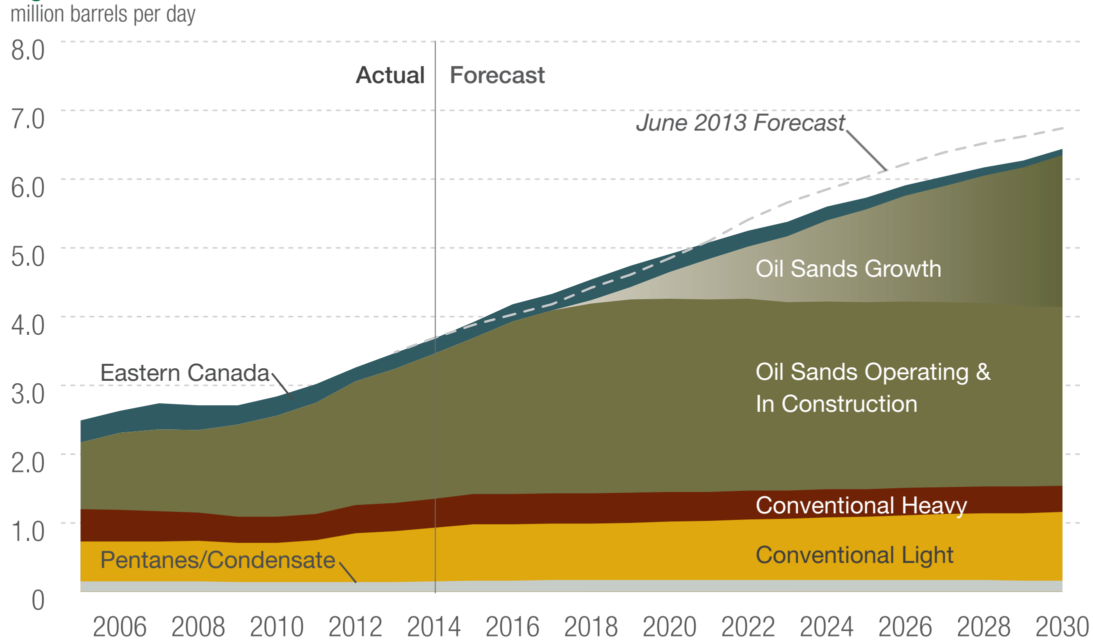
Relative to CAPP's 2013 report, western Candian production at the latter end of the outlook period is lower than previously forecast; in 2030 it is 300,000 b/d lower. Nonetheless, it is still expected to grow, on average, by 183,000 b/d per year through the forecast period. Conventional production is forecast to continue to contribute 1.5 million b/d to the total output on average over the forecast period. Compared to last year's forecast, conventional production is higher by 97,000 b/d in 2030; the majority of this uptick reflects the view that higher volumes of condensate will be available from industry's anticipated focus on drilling in liquids-rich natural gas plays.

Table 2.2 Western Canadian Crude Oil Production

million b/d	2013	2015	2020	2025	2030
Total*	3.24	3.68	4.65	5.57	6.35
Conventional (including condensate)	1.29	1.41	1.45	1.50	1.54
Oil sands (bitumen & upgraded)	1.95	2.27	3.20	4.07	4.81

*Totals may not add up due to rounding.

Figure 2.1 Canadian Oil Sands & Conventional Production



2.3.1 Conventional Crude Oil Production

The oil industry continues to search for innovative and more efficient ways to extract additional oil from conventional reservoirs. The increased use of horizontal drilling and multi-stage hydraulic fracturing techniques has reversed the steady decline in production from mature basins throughout North America since 2005.

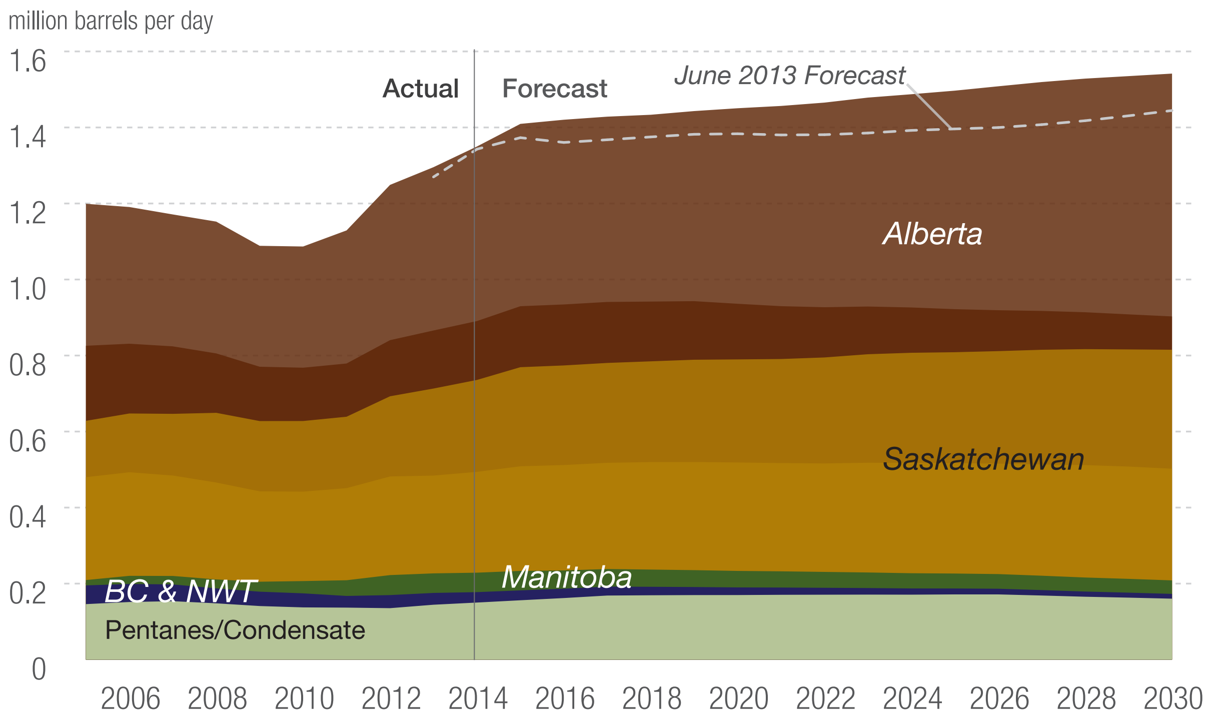
In 2013, western Canadian production, including condensates, was 1.3 million b/d, returning production to a similar level achieved 10 years ago. For purposes of this report, condensate refers to both pentanes plus and condensates. Further growth is anticipated as conventional production is forecast to ultimately exceed 1.5 million b/d, including growth in condensate production (Figure 2.2). Most of the condensate is primarily recovered from natural gas wells in Alberta and British Columbia. Increased drilling in liquids-rich plays such as the Montney and emerging plays like the Duvernay has reversed the declining trend in condensate production. Most of the conventional production comes from Alberta and Saskatchewan, of which over 60 per cent is light crude oil. By 2030, the light portion is forecast to increase to over 70 per cent of total conventional production.

Alberta

Alberta is the source for most of the condensate production in Western Canada with 123,000 b/d or 85 per cent of the total. In this year's forecast, some growth is expected in the early years followed by more stable levels of production. This is in contrast to the 2013 report, where condensate production was forecast to decline steadily. This revision reflects the increased activity and interest in west-central Alberta's Duvernay formation. The Duvernay is considered an attractive "shale gas" play because of its potential to produce liquids. There is strong demand for liquids to use as a diluent in the pipeline transportation of heavy oil production. According to the Alberta Energy Regulator (AER), the Duvernay formation holds 11.3 billion barrels of natural gas liquids resource. Early reports indicate high initial production rates and higher liquids yields for the wells drilled to date.

In 2013, conventional oil production in Alberta, excluding condensates, increased by 5 per cent compared to 2012, to 582,000 b/d. This production is forecast to increase by 144,000 b/d to 726,000 b/d by 2030. In last year's report, production was forecast to increase to 813,000 b/d by 2030. With only a few years of production data from horizontal oil wells in Western Canada, it is still too early to establish the ultimate recoveries and longer term flow rates for wells drilled using this newer technology.

Figure 2.2 Western Canada Conventional Production



Saskatchewan

Saskatchewan is the second largest oil producing province in Canada and has exhibited exceptionally strong growth in the last two years. Light oil production grew by 12 per cent and 9 per cent in 2012 and 2013 respectively, driven by tight oil play activity. In the next two years growth is expected to be quite strong before growing at a more measured pace for the remainder of the forecast. Saskatchewan's three main tight oil plays are the Bakken, Shaunavon and Viking.

In 2013, total (light and heavy) Saskatchewan oil production was 486,000 b/d and this is forecast to increase to 607,000 b/d by 2030. This is about 118,000 b/d higher than last year's forecast and reflects a further refinement to our forecast model, using updated decline rates and drilling trends from CAPP's survey of Saskatchewan producers.

Manitoba, British Columbia, NWT

Manitoba accounts for 4 per cent of the total conventional production from Western Canada, excluding condensates. Part of the Bakken play underlies a small portion of southwest Manitoba. Current production of 51,000 b/d is expected to decline gradually to 36,000 b/d by 2030.

British Columbia is the second largest provincial source of condensate production, accounting for 14 per cent of total production from Western Canada. With low natural gas prices, the liquids-rich and condensate component of the natural gas production stream has become critical to economic success for some producers. As such, there has been a shift in focus towards drilling in liquids-rich areas within the province's Montney play. In addition to condensates, the province also accounts for 2 per cent of total western Canadian conventional production.

Very little production currently comes from the Northwest Territories. However, the Canol oil shale formation is estimated to contain between 2 billion and 3 billion barrels of recoverable oil according to the government of the Northwest Territories. Development is still in its very early stages. Companies seeking to develop the Canol note that although the shale play is prolific, its remoteness, distance from markets, lack of infrastructure and inclement weather all pose significant challenges.

2.3.2 Oil Sands

Three designated oil sands areas in Northern Alberta have been established in order 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 AER estimated at year-end 2013 that these areas contain remaining established reserves of 167 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* (Latin for "in-place") techniques are employed, meaning wells are drilled. The term is used in reference to both primary development, which 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 oil sands reserves in Alberta, 33 billion barrels or 20 per cent is considered recoverable by mining and 134 billion barrels or 80 per cent can be recovered using *in situ* techniques.

Figure 2.3 Oil Sands Regions

Up until 2020, this latest oil sands forecast is relatively unchanged from last year and is mostly comprised of the production from the phases of the oil sands projects that are either already operating or are in the process of being constructed. During the latter part of the forecast from 2021 to 2030, oil sands production is on average about 360,000 b/d lower than CAPP's 2013 forecast due to a lower outlook mostly from *in situ* production.

In 2013, oil sands production totaled 1.9 million b/d. Of these volumes, 1.1 million b/d were recovered by *in situ* techniques. Mining production is forecast to grow to 1.6 million b/d by 2030. Most of the growth can be attributable to *in situ* production, which is forecast to grow to 3.2 million b/d by 2030 (Table 2.3).

Table 2.3 Oil Sands Production

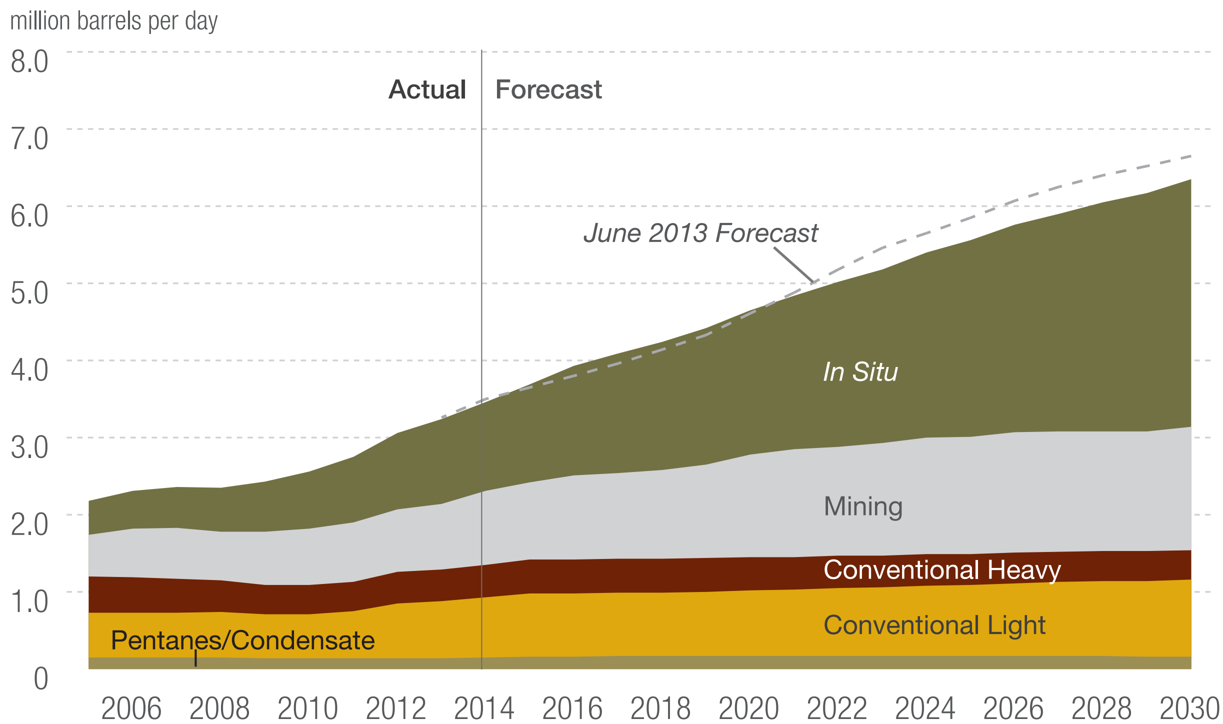
million b/d	2013	2015	2020	2025	2030
Total*	1.95	2.27	3.20	4.07	4.81
Mining	0.85	1.00	1.33	1.52	1.60
In Situ	1.10	1.27	1.87	2.55	3.21

*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 recovered from these projects. The yield losses associated with upgraded bitumen volumes from non-integrated projects have been accounted for in the supply volumes that are discussed in the next section of this report. Production from oil sands currently accounts for 60 per cent of Western Canada's total crude oil production. In this forecast, oil sands production rises from 1.9 million b/d in 2013, to 2.5 times this and reaches 4.8 million b/d by 2030 (Figure 2.4). The oil sands forecast in 2030, is approximately 400,000 b/d lower than forecast in the previous report due to a combination of factors including cost competitiveness and availability of financing.

Currently, Nexen's Long Lake project is the only *in situ* project coupled with upgrading facilities. 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 delivers diluted bitumen to the market. Some *in situ* volumes from Suncor's Firebag and MacKay River projects are upgraded at the Suncor upgrader.

Figure 2.4 Western Canada Oil Sands & Conventional Production



Existing integrated mining and upgrading projects are listed below:

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

2.4 Western Canadian Crude Oil Supply

Some volumes of raw bitumen are being transported to market by rail. However, the composition of the various crude types available in the market typically differs from crude oil at the production level. Both conventional heavy crude oil and bitumen from the oil sands are either upgraded or blended in order to be transported on pipelines 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 currently being transported by rail are 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 2013, about 1.1 million b/d or 55 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.

Canada's upgrading capacity is not expected to rise commensurately with bitumen production growth due to a number of economic challenges. These include the high capital costs incurred with building an upgrader 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. Less diluent is required when bitumen is moved by rail where it is transported in heated rail tank 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 forecast to grow slightly but will be insufficient to meet the needs of growing bitumen production that currently already exceed the available supply.

In 2013, almost 300,000 b/d of imported condensates, diluents from upgraders, as well as quantities of butane were needed to supplement the condensate supply from indigenous natural gas wells. CAPP's 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. To the extent rail becomes a more significant delivery system the reduction in the estimated need for diluent through the use of this transportation option will be reflected in future survey results and in turn, be incorporated in CAPP's future forecasts.

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 b/d on average for the outlook. Heavy crude oil supply is projected to grow from 2.0 million b/d in 2013 to 3.6 million b/d in 2020 to almost triple the current volume in 2030 when it reaches 5.7 million b/d.

Table 2.4 Western Canadian Crude Oil Supply

million b/d	2013	2015	2020	2025	2030
Total*	3.47	3.93	5.20	6.40	7.45
Light	1.46	1.54	1.57	1.71	1.78
Heavy	2.02	2.39	3.64	4.70	5.68

*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;
- Integrated mining and upgrading projects;
- Integrated *in situ* projects; and
- Off site upgraders.

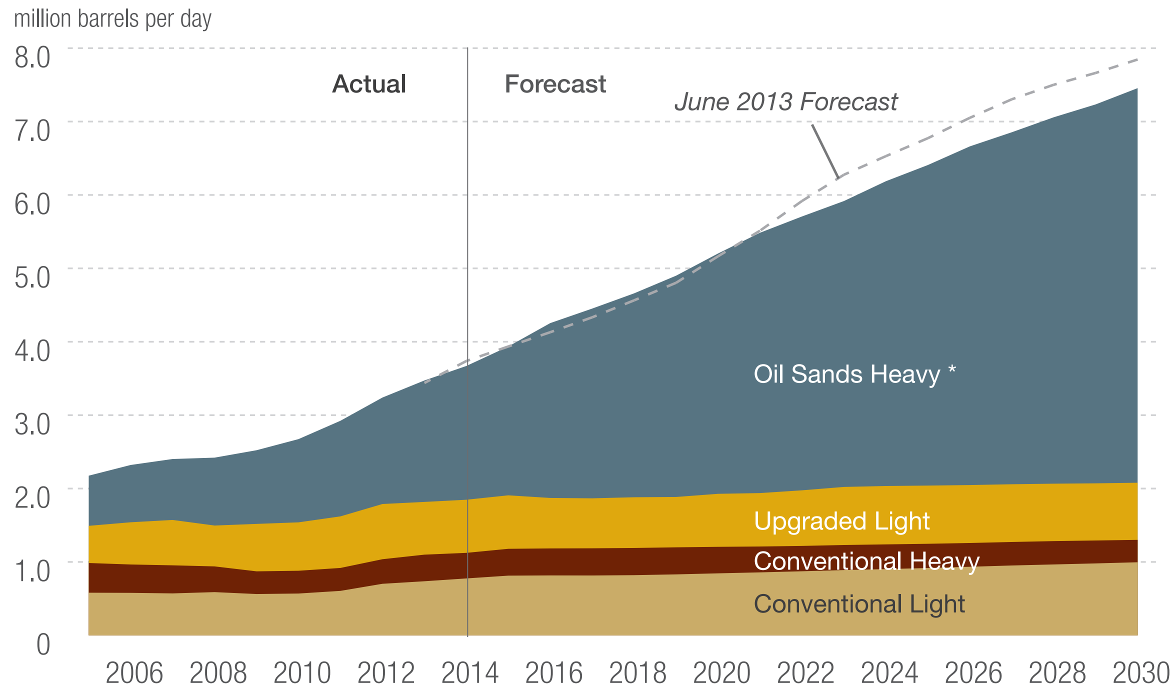
Compared to the 2013 forecast, the Upgraded Light crude oil supply is relatively unchanged. The Oil Sands Heavy category is forecast to increase from 1.7 million b/d to 5.4 million b/d by 2030 which is about 400,000 b/d lower than levels previously forecasted (Figure 2.5).

2.5 Crude Oil Production and Supply Summary

CAPP's 2014 crude oil production forecast for Western Canada predicts continued strong growth from 3.2 million b/d to 6.4 million b/d by 2030. Compared to the 2013 outlook, this latest forecast shows approximately 100,000 b/d higher forecast in conventional production, including condensates, and a 400,000 b/d lower forecast in oil sands production, the majority of which can be attributable to slower anticipated growth in *in situ* projects.

The production outlook from offshore Atlantic Canada is unchanged and 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. By 2030, however, production is forecast to decline to less than 100,000 b/d but could be higher than forecast given the announcement of three recent discoveries in the Flemish Pass Basin. The largest new prospect is the Bay du Nord, which is estimated to hold between 300 and 600 million barrels of recoverable oil.

Figure 2.5 Western Canada Oil Sands & Conventional Supply

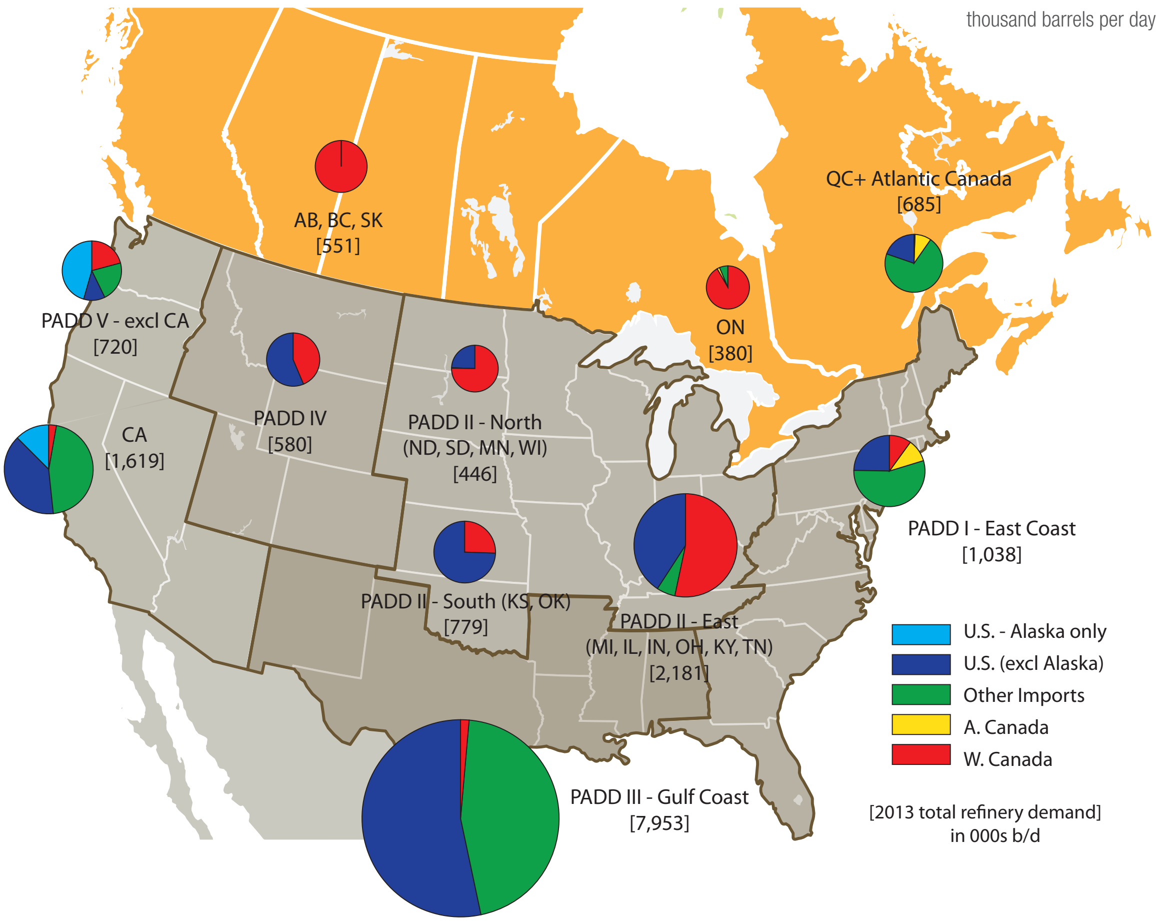


* Oil Sands Heavy includes some volumes of upgraded heavy sour crude oil and bitumen blended with diluent or upgraded crude oil.

3 | CRUDE OIL MARKETS

With 1.7 million b/d of additional crude oil supplies from Western Canada forecast to be available by 2020, expansion and diversification to all potential markets is key. Figure 3.1 shows the demand for crude oil in the major refining regions in Canada and the United States (U.S.). The U.S. Gulf Coast is a major target market due to the large heavy oil processing capability in the region. As identified by the areas in green, western Canadian crude could expand its share in PADD I, Eastern Canada, and PADD V markets. Also, beyond North America, global markets in Asia and even Europe, represent a potential opportunity.

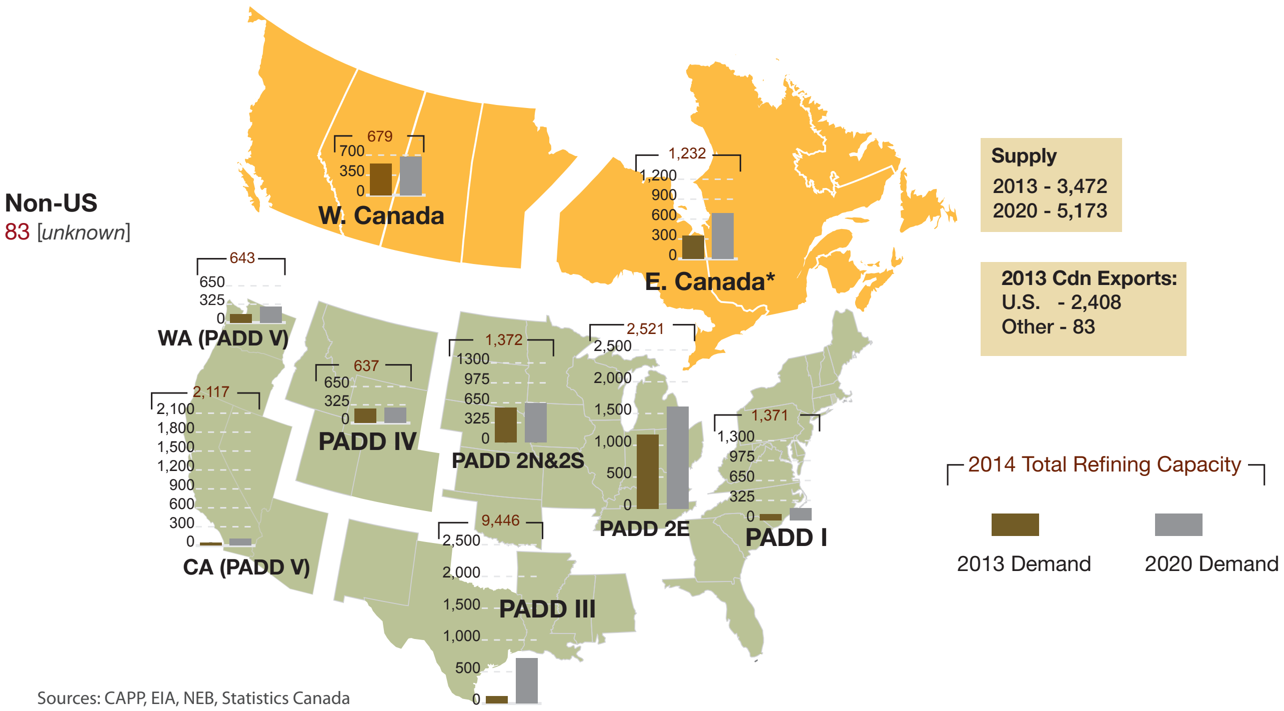
Figure 3.1 **Canada and U.S. Market Demand for Crude Oil in 2013 by Source**



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

Figure 3.2 Market Demand for Western Canadian Crude Oil: Actual 2013 and 2020

thousand barrels per day



Sources: CAPP, EIA, NEB, Statistics Canada

* E.Canada demand for W. Canadian crude oil in 2013 consisted almost entirely of receipts from Ontario. Projected receipts in 2020 include growth from Québec and Atlantic provinces.

Note: 2013 demand does not equal available supply due to factors such as inventory adjustment and data discrepancies in information collection.

In 2013, Canadian refineries processed 905,000 b/d of western Canadian crude oil. The remaining 2.6 million b/d or 74 per cent of available supply was exported. PADD II is the largest regional market for western Canadian crude oil. The bulk of the growth in supply volumes in 2020 is expected to flow to the U.S. Gulf Coast and Eastern PADD II. Eastern Canada and refineries on the West Coast could potentially process close to double the volume of their current intake of Canadian crude oil (Figure 3.2).

3.1 Canada

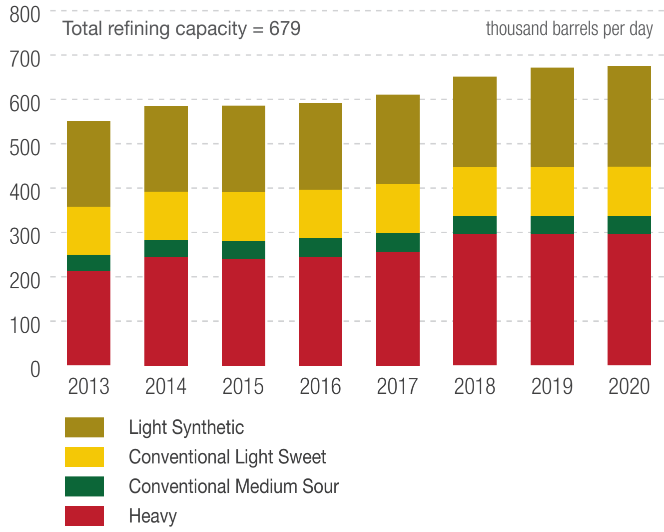
Canadian refineries have the capacity to process 1.9 million b/d of crude oil. However, only about 60 per cent of the crude oil processed in Canada is sourced from domestic production since refineries in Eastern Canada have limited access to western Canadian crude oil supplies. In 2013, Canadian refineries processed 905,000 b/d of western Canadian crude oil; 70,000 b/d of crude oil produced in Eastern Canada; and 642,000 b/d of foreign imports. The oil pipeline network exiting Western Canada currently connects to refineries in Western Canada and Ontario.

The refineries without pipeline access, however, are developing transportation solutions involving rail and/or trucks to benefit from growing North American sources of supply. The Canadian demand for western Canadian crude oil is expected to increase to 1.2 million b/d by 2020 as a result of planned refinery expansions and future transportation infrastructure developments.

3.1.1 Western Canada

Western Canada has a total refining capacity of 679,000 b/d from eight refineries. In 2013, these refineries processed 551,000 b/d of crude oil that was sourced exclusively from Western Canada. By 2020, western Canadian crude oil will remain the sole diet for these refineries and demand is expected to increase by 123,000 b/d to 675,000 b/d (Figure 3.3).

Figure 3.3 Western Canada:
Crude Oil Receipts from Western Canada



Source: 2014 CAPP Refinery Survey

The additional crude oil receipts in the future are related to a debottleneck project at the Moose Jaw refinery and expansion plans at the Consumer's Co-operative refinery, which are both located in Saskatchewan, and the startup of the North West Redwater Partnership's refinery near Redwater in Sturgeon County, about 45 km northeast of Edmonton, Alberta. The Sturgeon refinery is designed to process 50,000 b/d of raw bitumen feedstock under 30 year fee-for-service processing agreements. The Alberta Petroleum Marketing Commission, an agent of the province of Alberta, will supply 75 per cent of the feedstock and Canadian Natural Resources Limited will supply the rest. In December 2013, it was announced that the capital cost estimate increased to $8.5 billion from the original estimate of $5.7 billion. The original startup of operations has been extended from mid-2016 to September 2017. The project broke ground on September 20, 2013.

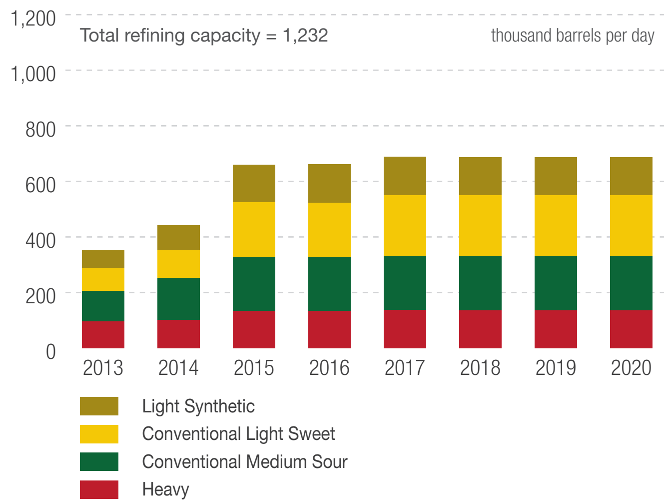
The Moose Jaw refinery is an asphalt refinery while the other refineries produce a wide range of petroleum products.

A project in the early stages of development has been proposed by newspaper publisher David Black, for a new export refinery to be located in Kitimat, British Columbia. The refinery would be designed to process 550,000 b/d of bitumen into gasoline, jet fuel and diesel for transportation to Asian markets. The estimated cost for the project is $21 billion.

3.1.2 Eastern Canada

Total capacity of refineries in Eastern Canada is about 1.2 million b/d and includes the refineries located in Ontario, Québec and Atlantic Canada. In 2013, Western Canada supplied 354,000 b/d to these refineries or only 33 per cent of total refinery demand. Almost all of these receipts were delivered to Ontario. Crude oil deliveries to the region increased in the past year through the use of rail. By 2020, overall demand in this market is expected to increase significantly (Figure 3.4). The reversal of the Enbridge Line 9 to Montréal by the end of 2014 will provide this market with access to Canadian crude oil. The TransCanada Energy East project proposes to provide access to Canadian crude in late 2018.

Figure 3.4 Eastern Canada:
Crude Oil Receipts from Western Canada



Source: 2014 CAPP Refinery Survey

Ontario

The four refineries located in Ontario have a combined refining capacity of 393,000 b/d. The NOVA Chemicals refinery and petrochemical complex, located in Sarnia, has been excluded 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.

Since August 2013, with the first phase of the Enbridge Line 9 re-reversal in operation, crude oil can flow east from Sarnia to North Westover, Ontario and can 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 data from the NEB and Statistics Canada, Ontario refineries processed 380,300 b/d of crude oil in 2013. A further breakdown of these supplies shows 356,700 b/d (94 per cent) from domestic sources; with the remainder comprised of imports from Norway, United Kingdom, Nigeria, Algeria and Mexico.

Québec & Atlantic Provinces

There are two refineries in Québec that have a combined capacity of 402,000 b/d. With the closure of Imperial's refinery in Halifax in June 2013, two refineries remain in operation in Atlantic Canada and they have a combined capacity of 435,000 b/d. The crude oil processed at these refineries generally originates from either Atlantic Canada or foreign sources. Both regions are expected to ramp up receipts of crude oil deliveries from Western Canada that began in recent years. The refineries are configured to process mostly light crude oil but future demand for heavy crude oil could increase if the refineries decided to invest in capital upgrades to enable processing heavier crude types. Suncor continues to assess the feasibility of building a coker at its Montréal refinery.

Once Enbridge's complete Line 9 re-reversal is in service, western Canadian crude oil could be transported by pipeline all the way to Montréal. 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 ship it by rail to the Irving refinery in Saint John, New Brunswick. By the end of 2018, if TransCanada's Energy East pipeline project proceeds, there will be pipeline access all the way from Western Canada to Saint John.

3.2 United States

Canada is the top foreign supplier of crude oil to the U.S. and is likely to remain as such for the foreseeable future. In 2013, almost all of Western Canada's crude oil exports were to the U.S. Despite rising U.S. domestic production driven by drilling in the shale and tight oil plays in the Eagle Ford in Texas and Bakken in North Dakota, U.S. imports from Canada grew by 158,000 b/d or 7 per cent versus 2012. Total U.S. imports of crude oil declined by 808,000 b/d or 9 per cent in 2013, mainly as a result of the displacement of foreign (non-Canadian) imports of light crude oil with domestic light supply. 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 when reporting data to describe the U.S. market regions.

3.2.1 PADD I (East Coast)

The refining capacity in the US East Coast currently totals 1.4 million b/d. The 10 refineries that form this capacity are located in the states of Delaware, Georgia, New Jersey, Pennsylvania, and West Virginia.

In 2013, total refinery input increased by 13 per cent compared to 2012 with the first full year return to operations of previously idled refineries. Imports of foreign crude oil by refineries in PADD I totaled 784,000 b/d, which is significantly lower than in 2012 due to a displacement of foreign imports with growing domestic supplies. The domestic portion of the feedstock slate increased from only 60,000 b/d to 254,000 b/d. This is an increase of 194,000 b/d or 322 per cent year over year.

Historically, the refineries on the East Coast have been supplied by waterborne crude oil delivered from the U.S. Gulf Coast and internationally sourced crude oil. However, with development of new rail unloading facilities, these refineries have growing access to Bakken crude oil produced in North Dakota. Phillips 66 and PBF have signed transportation agreements for the provision of Bakken crude supplies to their refineries located on the East Coast.

Table 3.1 Summary of Rail Offloading Terminals in PADD I

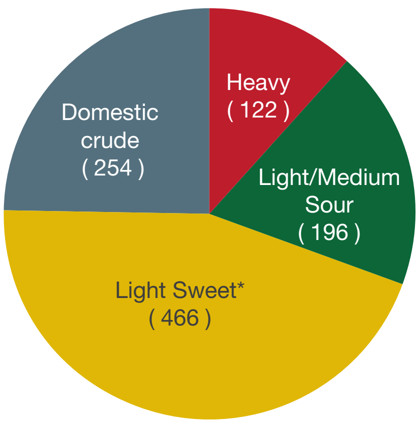
Operator	Location	Capacity (thousand b/d)	Scheduled In-Service	Description
PBF Energy (refinery)	Delaware City, DE	145 (105 light/40 heavy) Expand to 210 (130 light/ heavy)	Operating Q4 2014	Both light and heavy crude oil unloading capacity
Axeon Specialty Partners (refinery)	Savannah, GA	9* *based on 16 rail tank cars per day)	1H 2014	Crude oil that is shipped by rail to Savannah could conceivably move to Paulsboro via backhauls on waterborne vessels
Westville	Eagle Point (near Paulsboro), NJ			
Axeon Specialty Partners (refinery)	Paulsboro, NJ	small volumes Unit train capable	Operating 2014	Unit train capability is being contemplated
Buckeye Partners, L.P.	Perth Amboy, NJ	60-80	Q3 2014	Light crude; possible heavy in the future
Buckeye Partners, L.P.	Albany, NY	135	Operating since Nov 2012	Multi-year agreement with Irving refinery
Global Partners	Albany, NY	160 (estimated to be operating at 100)	Operating since 2011	Light crude oil receipts; seeking permit for facility to heat crude oil. Phillips 66 has 5 year contract for 50,000 b/d
Eddystone Rail Company (Enbridge JV)	Philadelphia, PA	80* *expandable to 160	Operating since May 2014	First train received on May 3, 2014.
Philadelphia Energy Solutions (refinery)	Philadelphia, PA	140	Operating since Oct 2013	
Plains All American Pipeline (PAAP)	Yorktown, VA	60	Operating since Dec 2013	First 98-car unit train received on Dec. 30, 2013
Total Existing Capacity				**709,000 b/d**

PADD I refineries imported 212,300 b/d of crude oil from Canada in 2013. About 83,900 b/d was sourced from Western Canada and was primarily delivered to the United refinery in Warren, Pennsylvania. Most of the refineries in the region process light sweet crude (Figure 3.5).

However, PBF's Paulsboro and Delaware City refineries have the coking capacity to process heavy crude oil from Western Canada. Also, modifications at Axeon Specialty Product's refinery in New Jersey will enable it to run both light and heavy crude oil feedstock.

Deliveries of U.S. domestic light crude oil supplies and imports of heavy crude oil from Western Canada could rise in the next few years as a result of growing rail transportation. Significant investments have been made in rail unloading facilities in recent years (Table 3.1). Refineries without direct access to rail unloading facilities can have rail deliveries to a terminal and then barged to the refinery.

Figure 3.5 2013 PADD I: Foreign Sourced Supply by Type and Domestic Crude Oil

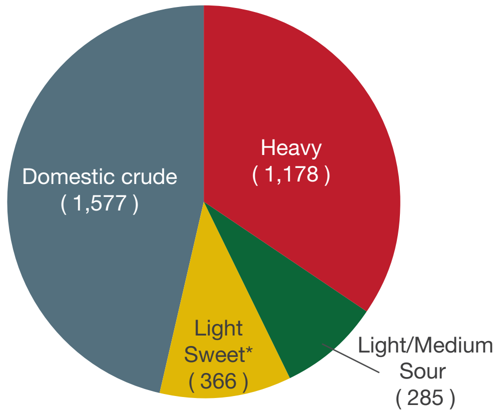


* Includes small volumes of Medium Sweet
Source: EIA

3.2.2 PADD II (Midwest)

Over 3.9 million b/d of refining capacity is located in PADD II. In 2013, these refineries received 1.8 million b/d of foreign sourced crude oil, almost all of which was from Western Canada and were predominantly heavy supplies (Figure 3.6).

Figure 3.6 2013 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. However, this traditional market is becoming saturated as evidenced by the high level of inventories from growing domestic production and imports from Western Canada.

Table 3.2 Summary of Recent Refinery Upgrades in Northern & Southern 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.
NCRA	McPherson, KS	85	Q1 2015	Plan to expand capacity to 100,000 b/d and increase heavy crude oil processing capacity to 50% with installation of new delayed coker.

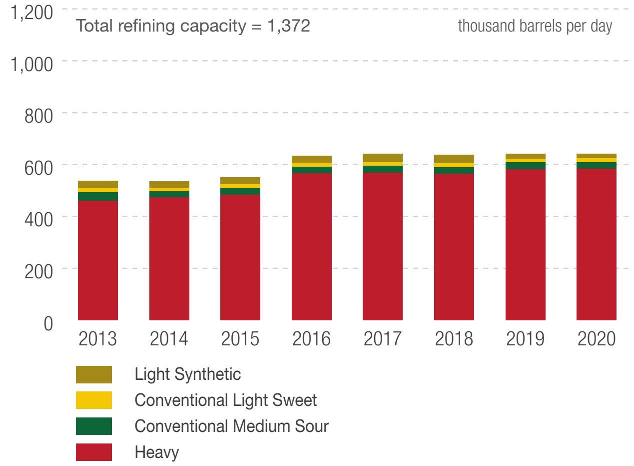
Northern and Southern PADD II

In Northern PADD II there are two refineries located in Minnesota, a refinery in Wisconsin and another refinery in North Dakota. The existing four refineries have a combined capacity of 564,500 b/d. Construction on a new refinery in North Dakota is scheduled for completion by the end of 2014. This refinery has a designed capacity of 20,000 b/d and is intended to process U.S. Bakken crude oil.

All seven refineries in Southern PADD II, are either located in Kansas or Oklahoma, and account for a combined capacity of 807,000 b/d. U.S. domestic production satisfies the majority (56 per cent) of the refinery feedstock demand in these two regions while almost all of the foreign imports into these two regions are sourced from Western Canada. Most, or 81 per cent, of the 538,000 b/d of western Canadian crude oil imports were heavy oil supplies.

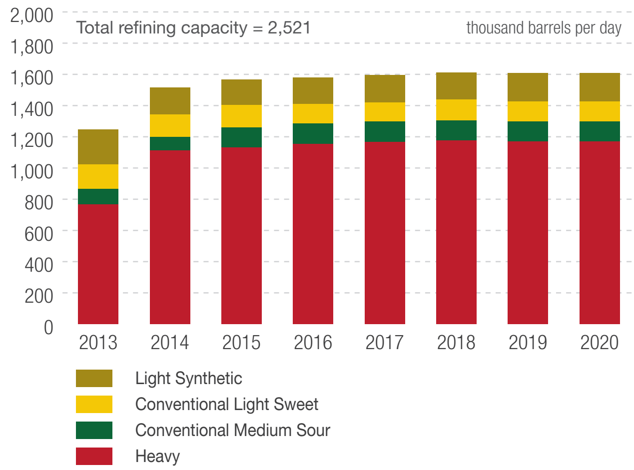
Given the small relative size of these two markets and competition with U.S. domestic production, the opportunity for western Canadian crude oil demand growth is limited. It is forecast to reach an additional 100,000 b/d from today's levels by 2020 (Figure 3.7).

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



Source: 2014 CAPP Refinery Survey

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



Source: 2014 CAPP Refinery Survey

Eastern PADD II

The total refining capacity in Eastern PADD II is over 2.5 million b/d from 14 refineries located throughout the six states of Michigan, Illinois, Indiana, Kentucky, Tennessee and Ohio. In 2013, this market collectively imported over 1.3 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 in 2020 (Figure 3.8). A number of previously announced refinery projects designed to increase heavy oil processing capacity at various refineries have recently been completed (Table 3.3).

Table 3.3 Summary of Recent Refinery Upgrades in Eastern PADD II

Operator	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Description
BP	Whiting, IN	413	Distillation unit completed July 2013 Coker completed Nov 2013	Construction of 102,000 b/d new coker and a new crude distillation unit. The refinery will have the capacity to process up to 80% heavy crude and expected to process Cdn in 2014.
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.
Husky	Lima, OH	160	2017	Modifications to coker and other processing units to increase ability to process heavy crude oil by up to 40,000 b/d.

3.2.3 PADD III (Gulf Coast)

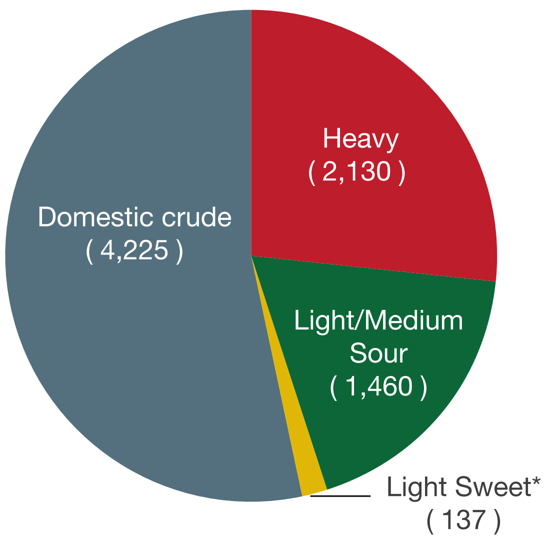
With 9.4 million b/d of refining capacity from 50 refineries, the Gulf Coast is home to half of the total refining capacity in the U.S. The vast majority of this capacity, specifically 8.6 million b/d, is located in the two states of Louisiana and Texas. The remaining refineries are located in Alabama, Arkansas, Mississippi, and New Mexico.

Greater access to this market would allow production from Canada to significantly expand its reach into the United States. Gulf Coast refineries are among the most sophisticated in the world, meaning that they are able to produce different types of petroleum products from a variety of crude oil feedstocks. These refineries have the capacity to process heavy, high sulphur crude oil, which is ideally suited for the growing supplies from Western Canada, the bulk of which are expected to be heavy crude oil.

Foreign imports of crude oil totaled 3.7 million b/d in 2013, which was a decline of 17 per cent from 2012. Surging production from U.S. shale and tight oil plays such as the Eagle Ford and Permian Basin in Texas, has enabled refineries along the U.S. Gulf Coast to satisfy their light crude oil feedstock requirements with domestic supplies instead of light-sweet crude imports.

Figure 3.9 2013 PADD III: Foreign Sourced Supply by Type and Domestic Crude Oil

Total refining capacity = 9,446 thousand barrels per day



* Includes small volumes of Medium Sweet
Source: EIA

The 2.1 million b/d of heavy crude oil imports in 2013 remained relatively unchanged from 2012. Due to pipeline constraints, only 118,000 b/d of western Canadian crude was able to reach the U.S. Gulf Coast region. The top three suppliers of foreign crude oil in declining order are: Saudi Arabia, Mexico, and Venezuela; which combined account for 67 per cent of total imports. Venezuela, Mexico, and Columbia collectively account for 77 per cent of all heavy imports. Crude oil imports from Saudi Arabia consist mostly of light and medium sour crude oils. The opportunity for growing supplies from Western Canada to gain a presence in this market once the transportation capacity is in place lies in the displacement of heavy imports and not competition with U.S. domestic production, which is primarily light crude oil.

Since 2010, crude oil imports from Mexico have been steadily declining and in 2013 fell by 116,000 b/d to 919,000 b/d, reflecting the decline in Mexico's crude oil production. The annual imports from Venezuela in 2013 hit a 20-year low, falling by a dramatic 17 per cent to 755,000 b/d. Venezuela is reported to be exporting 640,000 b/d to China with about 310,000 b/d being used to pay back loans. Despite Venezuela having the world's largest reserves of crude oil, growth in production will be difficult to achieve and significant capital investments will be required. If there is no substantial growth in production, exports to the U.S. will continue to decline as Venezuela has substantial supply commitments to China, Cuba, the Dominican Republic and Nicaragua.

There are currently two pipelines in service that provide a limited connection between western Canadian producers and the U.S. Gulf Coast market. Further expansions upstream are required for significant volumes of western Canadian crude to enter this market. The U.S. Gulf Coast was the largest market for movements of crude by rail in 2013. CAPP's 2014 refinery survey indicates that western Canadian crude oil supplied to this market could reach 709,000 b/d in 2020.

3.2.4 PADD IV (Rockies)

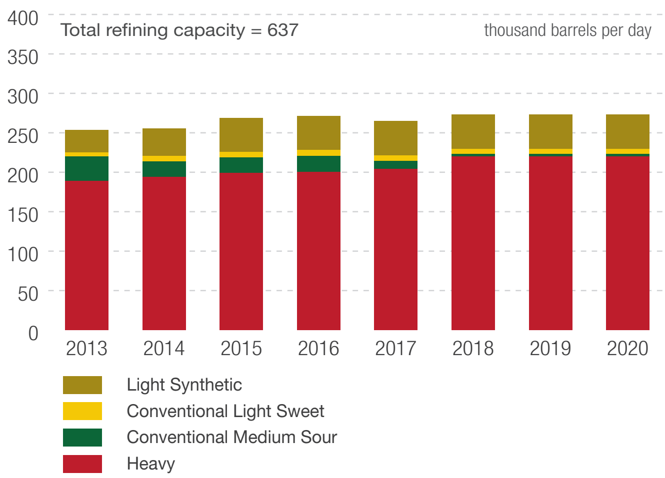
There are 14 refineries in PADD IV located in Colorado, Montana, Utah, and Wyoming with a combined refining capacity of 637,000 b/d. The refineries in this market process U.S. domestic crude oil supplies from the Bakken oil play and source all foreign imports from Western Canada.

Table 3.4 Summary of Recent Refinery Upgrades in PADD III

Operator	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Description
Calumet Specialty Products	San Antonio, TX	17.5	Completed Dec 2013	Expansion to crude unit increased capacity from 14,500 b/d to 17,500 b/d.
Marathon	Garyville,LA	522	2018 (decision in early 2015)	Installation of hydrotreating, hydrocracking, & desulfurization equipment.
Valero	McKee, TX	170	2014	Increase capacity by 25,000 b/d. Expansion will process WTI and locally produced crude oil.
LyondellBasell Industries NV	Houston, TX	268	2015	Increase ability to process heavy crude oil from 60,000 b/d to 175,000 b/d.

In 2013, PADD IV refineries processed 253,000 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 at current levels. If Canadian heavy crude oil continues to be priced at an attractive discount, refineries are expected to continue to process 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

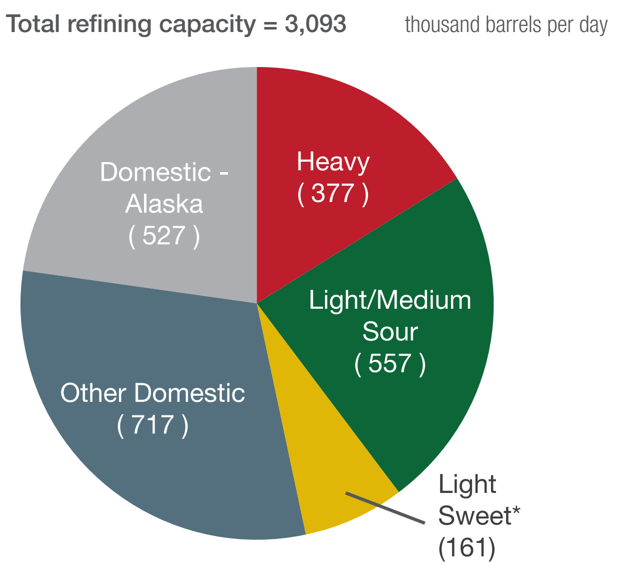


Source: 2014 CAPP Refinery Survey

3.2.5 PADD V (West Coast)

PADD V is 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 3.1 million b/d of refining capacity in the region. Foreign imports typically supply almost 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 2013 PADD V: Foreign Sourced Supply by Type and Domestic Crude Oil



* Includes small volumes of Medium Sweet
Source: EIA

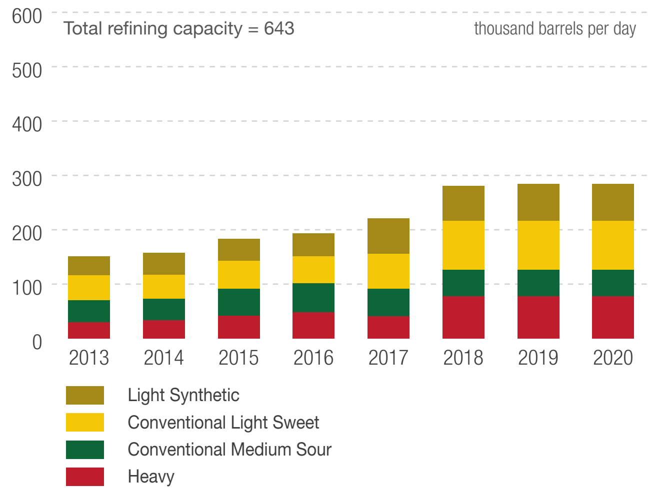
The following discussion focuses only on Washington and California as the demand from refiners located in these two states account for both the current and future prospects for western Canadian crude oil in this region.

Washington

Refining capacity in Washington totals 643,000 b/d. The state's five refineries have been primarily supplied with Alaskan production delivered by tanker but production from this source continues to decline. At 515,000 b/d in 2013, Alaskan production is only about a quarter of the peak levels achieved in 1988. Note that the state's supplies could rebound as the repeal of a production tax triggers investments that may boost output by at least 90,000 b/d within four years. However, in the meantime, Washington refineries have become increasingly dependent on foreign imports but some have also recently been able to access some of the growing crude oil production supply in North Dakota through the use of rail.

In 2013, Washington refineries received 223,000 b/d of foreign imports of which 68 per cent was supplied by Canada. Saudi Arabia and Russia are the second and third main suppliers with 14 per cent and 3 per cent shares of the market, respectively. Results from CAPP's refinery survey indicate crude oil demand from Western Canada will increase by 133,000 b/d from current levels, which translates to an 88 per cent increase (Figure 3.12). This growth in demand relies on the successful construction of proposed rail or pipeline projects that would reach the West Coast. Refer to Section 4.5 for details on the Pipelines to the West Coast.

Figure 3.12 PADD V (Washington): Crude Oil Receipts from Western Canada



Source: 2014 CAPP Refinery Survey

A few refineries began investing in rail offloading facilities in recent years in order to access growing supplies of crude oil from North Dakota and Western Canada. All the refineries in Washington either are already receiving some crude shipments by rail or have plans to do so by the end of the year.

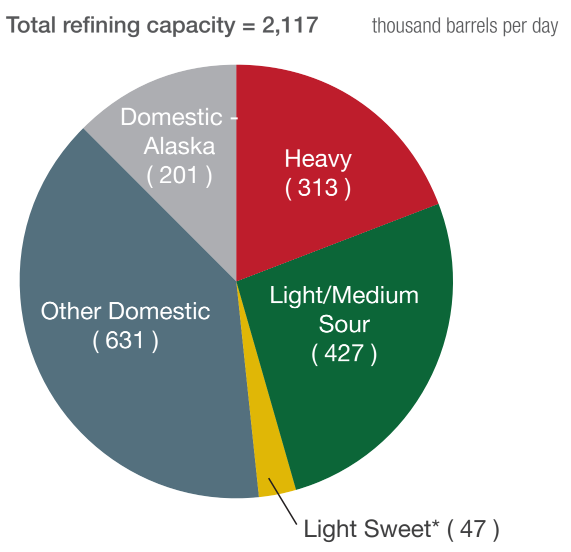
California

California dominates PADD V in terms of state oil production and refining capacity. There are 16 refineries located in California that contribute to a total refining capacity of 2.1 million b/d in the state. Almost all of the refineries are located near the coast in the Los Angeles and the San Francisco Bay areas. There is no direct pipeline to California from producing regions outside of California. Therefore, as Alaskan crude oil declines an opportunity arises to process more crude oil from the Bakken in North Dakota and potentially from Canada. Refer to Section 4.5 for pipeline proposal projects connecting western Canadian crude oil to the West Coast where the crude oil could then be loaded on to tankers to serve these refineries.

A number of rail unloading projects are being pursued that would increase access. Four major projects are currently planned that have a combined capacity of 326,000 b/d by early 2016 (Table 3.5).

In 2013, California refineries imported 786,000 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.

Figure 3.13 2013 PADD V (California): Foreign Sourced Supply by Type and Domestic Crude Oil



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

Table 3.5 Summary of Rail Offloading Terminals in Western Canada and PADD V

Company	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Description
Western Canada				
Chevron (refinery)	Burnaby, B.C.	8	Operating since 2013	
Western Canada capacity subtotal			**8,000 b/d**	
Washington				
Shell (refinery)	Anacortes, WA	50	?	Applied for permits
Tesoro (refinery)	Anacortes, WA	50	Operating since 2012	
BP (refinery)	Cherry Point/Blaine, WA	60	Q3 2014	In construction
Phillips 66 (refinery)	Ferndale, WA	small volumes Expansion to 30	Operating Dec 2014	Currently receiving manifest trains; applied for permits for expansion
US Oil (refinery)	Tacoma, WA	30	Operating since 2012	Unit train capable
US Development Group	Grays Harbour, WA	50	2016	Applied for permits
Westway	Grays Harbour, WA	27	Q1 2015	Applied for permits
Imperium Renewables	Grays Harbour, WA	?	?	Applied for permits; would accept other products besides crude oil
Tesoro/Savage	Port of Vancouver, WA	120 (expandable to 280)	2017	Applied for permits
Global Partners of Massachusetts	Port Westward/ Calskanie, WA	65 (expandable to 130)	Operating since Q4 2012	24 trains per month; expandable to 50
Washington capacity subtotal		**145,000 b/d; potential for additional 337,000 b/d**		
California				
Alon USA	Bakersfield, CA	manifest; Expansion to 150	Operating Q4 2015	Heavy and light crude oil capacity
Plains All American	Bakersfield, CA	65	Q1 2015	
Valero (refinery)	Benicia, CA	70	Q1 2015	western Cdn crude + US
Phillips 66 (refinery)	Santa Maria, CA	41	Q1 2016	
California capacity subtotal		**manifest trains; potential for additional 326,000 b/d**		
TOTAL		**153,000 b/d; potential for additional 663,000 b/d**		

Recent surveys from the U.S. Energy Information Administration have indicated that 15.4 billion barrels of oil remain that could be technically recovered in California. This is 64 per cent of the total recoverable shale oil in the U.S., so the potential of California unconventional oil is enormous; but there is still a lot to be learned before these shale plays can become commercial. Plays such as the Monterey and the Kreyenhagen have yet to be properly assessed, the efficiency of regulatory compliance still has to be improved and appropriate stimulation techniques need to be identified. If these issues are resolved, California could undergo an unconventional oil renaissance similar to that of Texas.

3.3 International

There is growing interest in Canada's crude oil suppy from both Europe and Asia. It was reported in May 2014 that the first shipment of oil sands crude oil was transported to Spain to be processed at refineries in Spain. Asia is the world's fastest growing energy market. New refineries with heavy oil processing capacity are being built in Asia. In contrast, demand for oil in North America is stable and perhaps declining. Table 3.6 shows oil demand from 2011 to 2014 in major Asian markets.

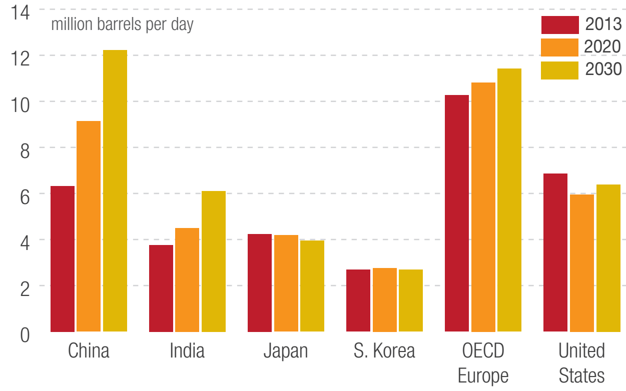
Table 3.6 Total Oil Demand in Major Asian Countries

million b/d	2011	2012	2013	2014
China	9.32	9.83	10.10	10.45
India	3.20	3.35	3.37	3.46
Japan	4.47	4.73	4.56	4.41
Korea	2.26	2.30	2.31	2.31

Source: IEA Oil Market Report, April 2014

Figure 3.14 shows the changing global import needs.

Figure 3.14 Global Net Oil Imports: 2013 to 2030



Source: EIA 2014 Annual Energy Outlook

3.4 Markets Summary

The anticipated growth in western Canadian crude oil production could potentially be absorbed by demand from a number of market regions subject to development in the North America transportation infrastructure.

The U.S. Gulf Coast is a target market of considerable size and is particularly suitable for supplies from Western Canada given the heavy oil processing capacity of the refineries located in the region. Eastern PADD II is currently the largest market for western Canadian crude oil and could process over 400,000 b/d of additional volumes by 2020. Refineries in Eastern Canada and PADD I have also indicated that they could potentially process double the current deliveries of western Canadian crude oil. The development of new rail infrastructure is planned in both PADD I and PADD V, some of which will have the ability to offload heavy crude oil. California refineries are configured to process a significant portion of heavy and medium sour crude oil. With the decline of Alaskan production, one of the major traditional crude sources of supply to California refineries, producers from Western Canada could deliver supplemental supplies via rail. Canadian producers are also focusing on opportunities to reach non-U.S., global markets such as China, whose net oil imports are forecast to grow by almost 3 million b/d by 2020.

4 | TRANSPORTATION

The growing supply of crude oil from Western Canada is rapidly filling the existing pipeline capacity and extended timelines for regulatory approvals combined with other uncertainties have affected the evolution of the transportation network. Other forms of transport, such as railways, barges and marine tankers are quickly becoming additional means to distribute increasing volumes of western Canadian crude oil to markets throughout North America and beyond. The existing pipeline infrastructure and the proposed pipeline projects, however, will continue to provide essential take away capacity from the Western Canada Sedimentary Basin (WCSB) to all key markets. There are a number of pipeline projects in the regulatory process or being considered that could deliver large volumes to the East Coast, West Coast, U.S. Gulf Coast and offshore (Figure 4.1).

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

4.1 Existing Crude Oil Pipelines Exiting Western Canada

There are four major pipelines that move western Canadian crude out of the WCSB. Both the Enbridge Mainline pipeline and the Kinder Morgan Trans Mountain pipeline originate at Edmonton, Alberta. The Spectra Express pipeline and the TransCanada Keystone pipeline originate at Hardisty, Alberta. Together, these pipelines provide about 3.7 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 given growing production volumes. In addition, operational constraints can and have reduced available capacity to below nameplate capacity.

Table 4.1 Major Existing & Proposed Crude Oil Pipelines Exiting the WCSB

Pipeline	Capacity (thousand b/d)	Target In-Service
Enbridge Mainline	2,500	Operating since 1950
Enbridge Alberta Clipper Expansion	+350	Q3 2015
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 **assuming approval obtained by end 2014	+830	2017**
Enbridge Northern Gateway	+525	Q3 2018
TransCanada Energy East	+1,100	Q4 2018
Total Existing Capacity		**3,671**
Total Proposed Additional Capacity		**+3,395**

The next sections describe the existing pipeline projects. The proposed projects are discussed in the subsequent sections and are categorized 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: Line 9 at Sarnia, Ontario; 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 2.5 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 to transport 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 30-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 would enter the Enbridge Mainline at Superior, Wisconsin instead. The target in-service date for this project is March 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 Projects

Enbridge has announced that it will be undertaking a $7 billion project to replace its Line 3 pipeline which currently transports light crude oil from Edmonton, Alberta to Superior, Wisconsin. The new line is scheduled to be in service in the second half of 2017.

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.

Enbridge plans to expand the Alberta Clipper pipeline by 350,000 b/d in Q3 2015 through the addition of new pumps and station upgrades. The Alberta Clipper is a 36-inch diameter pipeline which extends from Hardisty, Alberta to Superior, Wisconsin and has a current capacity of 450,000 b/d. Upon completion of the expansion, the Alberta Clipper line will have reached its ultimate designed 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 Q3 2015 through the addition of pumping stations. Upon completion of these expansions, the Southern Access pipeline will have reached its ultimate designed capacity of 1.2 million b/d.

4.1.2 Spectra Express-Platte

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 but the ability to move crude on it is limited due to insufficient downstream capacity on the Platte pipeline. However, recent rail connections have helped to increase throughput capacity. Spectra held a successful Open Season to determine new interest in contracted capacity on Express from June 5 to August 9, 2013. Contracted capacity increased from 119,000 b/d to 225,000 b/d. The contract lengths range from 1.5 years to over 11 years. The first contract commenced in October 2013 while the remaining contracts will be phased in over two years.

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.

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 Washington and to points in British Columbia, including the Westridge marine terminal located at Burnaby. From the marine terminal, 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 is 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. Demand for access to this pipeline has been high and as such the nominations for service on this pipeline have been apportioned since late 2010.

4.1.4 TransCanada Keystone

The Keystone pipeline system originates at Hardisty, Alberta and connects to Steele City, Nebraska. From this juncture 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 with each destination capable of taking this maximum capacity if shippers so elect. The pipeline started operations in June 2010 to serve the Wood River/Patoka markets while the Cushing extension came online in February 2011. About 530,000 b/d of capacity is contracted for an average of 18 years.

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 TransCanada Energy 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 with a total capacity of 2.75 million barrels and terminal facilities at the Edmonton South terminal. The estimated cost is $1.8 billion. The target in-service Q2 2015.

4.2.2 TransCanada - Alberta Regional Pipelines

Heartland Pipeline and Terminal

TransCanada is proposing a 36-inch diameter pipeline from the Heartland region to Hardisty, Alberta, which is the starting point of its Keystone pipeline system. Heartland is an industrial area north of Edmonton, Alberta. The initial capacity would be 500,000 b/d but the pipeline could be expanded to 900,000 b/d. At Hardisty, Alberta the pipeline would have connections to Keystone, Keystone XL and Energy East. In the Heartland region, there will be up to 1.9 million barrels of tank capacity available. Regulatory approvals are expected in Q3 2014 while the target in-service date for the Heartland pipeline is 2016.

Grand Rapids Pipeline Project

TransCanada in partnership with Phoenix Energy Holdings Limited (Phoenix) is proposing 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. The crude oil pipeline is targeted to be in service by mid-2015 with the complete project targeted for in-service in 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. The proposed extension would be a 24-inch diameter pipeline with an initial capacity of 300,000 b/d. The pipeline is targeted to be in-service date by mid 2015.

4.3.4 Enbridge Line 6B

As part of Enbridge's Eastern Access Phase 1 program, the segment of the 36-inch diameter Line 6B will be replaced from Griffith, Illinois to Stockbridge, Michigan in Q2 2014. This would increase capacity from 240,000 b/d to 500,000 b/d. Subsequently in Q3 2014, with Phase 2 of the program, the remaining segment from Stockbridge, Michigan to the U.S./Canada border will also be replaced and yield a corresponding increase in capacity.

As part of its Light Oil market access program, Enbridge is proposing to increase capacity of the Line 6B between Griffith, Illinois and Stockbridge, Michigan from 500,000 b/d to 570,000 b/d. The target in-service date is Q1 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.

4.3.6 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 (also referred to as Line 62) or to Cushing, Oklahoma on Spearhead South (also referred to as Line 55). The capacity on Spearhead North was recently expanded to 235,000 b/d. As part of its Light Oil Market Access project, 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.

4.3.7 Enbridge Toledo Pipeline Expansion

Enbridge operates a pipeline that connects with the Mainline near Stockbridge, Michigan and extends east and south, terminating near Romulus, Michigan. This 20-inch diameter pipeline, known as Line 79, has been operating since May 2013 and has a capacity of 80,000 b/d. Line 17 is a 16-inch diameter pipeline that extends from Stockbridge, Michigan to Toledo, Ohio and has a capacity of 100,000 b/d. With these two pipelines, a total capacity of 180,000 b/d is now available to satisfy refineries in Toledo, Ohio and Detroit, Michigan.

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 - Q3 2015	400 +160 +640
Enbridge Spearhead North	Flanagan, IL	Chicago, IL	Operating	235
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

4.4 Oil Pipelines to the U.S. Gulf Coast

The U.S. Gulf Coast represents the most significant market growth opportunity 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.

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

4.4.1 Enbridge Flanagan South

The Flanagan South Pipeline is a proposed 36-inch diameter pipeline that will have an initial capacity of 585,000 b/d in heavy crude oil service. The pipeline is essentially a twin pipeline to the existing Enbridge Spearhead South Pipeline, which originates at Flanagan, Illinois and terminates at Cushing, Oklahoma. The pipeline is currently under construction and is targeted to be in-service in Q3 2014.

4.4.2 Enbridge/Enterprise Seaway

The Seaway Pipeline is jointly owned by Enbridge Inc. and Enterprise Products Partners L.P. The pipeline transports crude oil from Cushing, Oklahoma to the U.S. Gulf Coast. The capacity on the pipeline was increased to 400,000 b/d (light crude equivalent) in 2013. Enbridge and Enterprise have secured sufficient commercial support to build a new twin line alongside 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 will be 450,000 b/d. Once completed, the Seaway pipeline system would have a total capacity of 850,000 b/d. The target in-service date for the Seaway twin is Q2 2014 while the lateral from Jones Creek to Port Arthur/Beaumont is scheduled for Q3 2014.

4.4.3 TransCanada Keystone XL

Over five years ago, TransCanada first applied for a Presidential Permit to build the Keystone XL (KXL) pipeline, a proposed pipeline from Hardisty, Alberta to Steele City, Nebraska. Since then, a revised route was submitted and multiple studies have been completed indicating that the project will not have a significant impact to the environment and will provide sizeable economic benefits. A Final Supplemental Environmental Impact Statement was released on January 31, 2014. On April 18, 2014, the U.S. Department of State announced that there will be a further delay to complete the review process. Should the project be approved, it would provide 830,000 b/d of capacity.

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.

Keystone XL and the Bakken Marketlink Project are expected to be in service two years following the receipt of a Presidential Permit.

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

Pipeline	Originating Point	Destination	Status	Capacity (thousand b/d)
Seaway	Cushing, OK	Freeport, TX	Operating	400
Seaway Twin Line			Proposed - Q2 2014	+450
TransCanada Keystone XL	Hardisty, AB	Steele City, NE	Proposed - 2017	+830
TransCanada Cushing Extension	*Steele City, NE*	*Cushing, OK*	*Operating since Feb 2011*	
TransCanada Gulf Coast	*Cushing, OK*	*Nederland, TX*	*Operating since Jan 2014*	700
			Proposed - TBD	+130

4.4.4 TransCanada Gulf Coast

TransCanada's Gulf Coast Project started delivering crude oil on January 22, 2014. The 36-inch diameter pipeline is part of the Keystone Pipeline system and provides capacity from Cushing, Oklahoma to Port Arthur and Houston, Texas. During the first year of operations, the capacity is expected to average 520,000 b/d before ramping up to 700,000 b/d.

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 offloaded 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.

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 has issued a decision recommending that the project be approved and a final decision on whether the project will be approved is expected to be made by the Governor in Council in June 2014. The target in-service date for the project is Q3 2018.

4.5.2 Kinder Morgan Trans Mountain Expansion

On December 16, 2013, Kinder Morgan submitted an application to the National Energy Board (NEB) for an expansion to its existing Trans Mountain pipeline (see section 4.1.3). The capital cost for the Trans Mountain Pipeline Expansion project (TMX) is estimated at $5.5 billion. If approved and constructed, the expanded system would be comprised of two parallel pipelines. Line 1 would consist of existing pipeline segments and could transport 350,000 b/d of refined petroleum products and light crude or potentially heavy crude oil, but at a loss of capacity. The proposed Line 2 would have a capacity of 540,000 b/d and would be allocated to the transportation of heavy crude oil. This new pipeline and configuration set-up would, in effect, add 590,000 b/d to the existing 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 from 13 shippers. If approval was recommended in a NEB decision by July 2015, and final approval granted by Governor in Council three months later, then construction could start in late 2015 with the proposed expanded system in operation in December 2017.

4.6 Oil Pipelines to Eastern Canada

In 2013, refineries in Eastern Canada imported 642,000 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 a significant opportunity for western Canadian producers. Table 4.5 lists the pipeline proposals that could be conduits to this market.

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 - Q3 2018	+525

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 9A 9B	Sarnia, ON Sarnia, ON North Westover, ON	Montréal, QC North Westover, ON Montréal, QC	Proposed Operating since Aug 2013 Q3 2014	+300
TransCanada Energy East	Hardisty, AB	Québec City, QC / St. John, NB	Proposed - Q4 2018	+1,100

4.6.1 Enbridge Line 9 Reversal

Enbridge Line 9 is a 30-inch diameter crude oil pipeline that recently ran westward from Montréal, Québec to Sarnia, Ontario. The 9A portion of the pipeline started operating in reversed flow, transporting crude oil east from Sarnia, Ontario to North Westover, Ontario in August 2013.

In March 2014, Enbridge received approval to reverse the remaining portion, also known as Line 9B to eventually flow east from North Westover, Ontario to Montréal, Québec and to increase the capacity by 60,000 b/d from 240,000 b/d. The target in-service date for the Line 9B reversal is Q4 2014.

4.6.2 TransCanada Energy East

The TransCanada Energy East Pipeline Project includes the conversion of a natural gas pipeline to oil service and new pipeline segments to provide transportation service from Hardisty, Alberta and Moosomin, Saskatchewan to delivery points in Québec and New Brunswick. The delivery points include three existing refineries in Eastern Canada and two marine terminals, one at Cacouna, Québec and one at Saint John, New Brunswick to allow for exports to international markets. The proposed pipeline would have a capacity of 1.1 million b/d, of which 900,000 b/d is underpinned by firm contracts. The scheduled in-service date for the project is Q4 2018.

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. About 43 per cent (77,000 b/d) of this capacity is allocated to committed shippers.

Enbridge offered another 50,000 b/d of capacity on the pipeline for commitments from shippers through an Open Season held from January 28 to February 27, 2013. Potential shippers were given a choice of five available start dates between July 1, 2013 and July 1, 2014. All contracts would expire on June 30, 2025, with an option to extend the term for an additional 15 years. The minimum volume commitment will be 5,000 b/d. Due to the success of the Open Season, Enbridge is developing a future expansion of the Southern Lights system to increase capacity to 275,000 b/d through the use of additional horse power and drag reducing agents.

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 - Q3 2018	+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

4.7.2 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. A final decision on whether the project will be approved is expected to be made by the Governor in Council in June 2014. The target in-service date for the project is Q3 2018.

4.7.3 TransCanada Grand Rapids Diluent

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

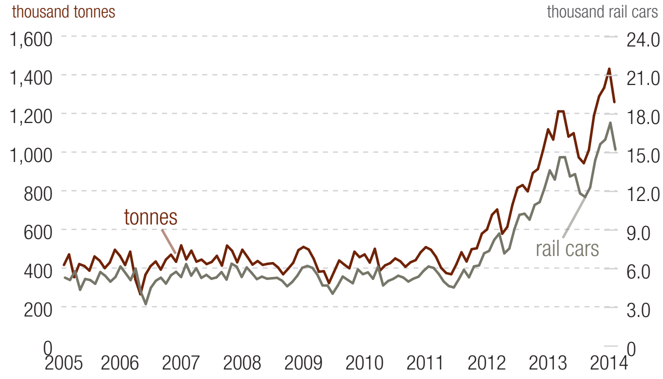
4.7.4 Kinder Morgan Cochin Reversal Project

Kinder Morgan announced on June 5, 2012 that it had completed a binding open season to reverse its Cochin propane and ethane-propane pipeline to carry 95,000 b/d of condensates from Illinois to terminals in Fort Saskatchewan, Alberta. Kinder Morgan has secured commitments for at least 10 years for 100,000 b/d of capacity during the open season. The reversal will help transport light condensate from the Eagle Ford shale and the U.S. Gulf Coast to the Canadian market. The pipeline is targeted to begin service on July 1, 2014. For a total cost of US$225 million, the project will link the Cochin pipeline with the Explorer products pipeline, which carries refined petroleum products from the U.S. Gulf Coast to the Midwest in Kankakee County, Illinois and reverse Cochin to move condensate northwest to Alberta.

4.8 Crude Oil by Rail

In recent years, rail transport of crude oil has grown to accommodate the rapid growth from new supply regions that quickly exceeded the available pipeline capacity to desirable markets. The number of Canadian rail tank car loadings of crude oil and petroleum products reached over 17,000 carloads in January 2014 (Figure 4.2).

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

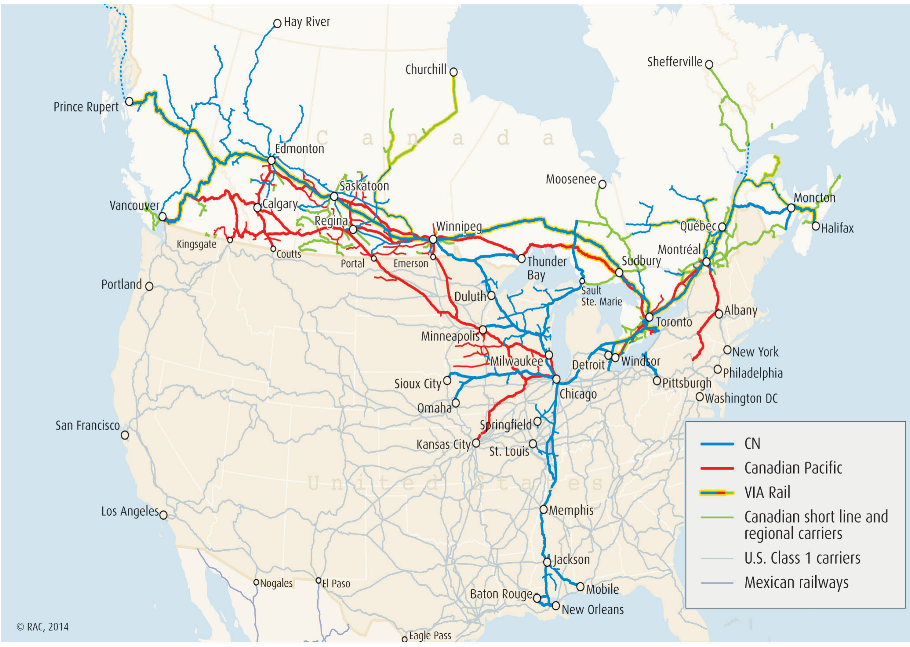


Source: Statistics Canada

Producer Benefits of Rail

- ***Speed to Market****: A unit train averages 28 km/hr. Getting oil to the refinery quickly means producers are paid sooner and refiners receive feedstock sooner.*
- ***Optionality/Flexibility:*** *There are already existing rail tracks in place to reach East Coast, West Coast and Gulf Coast markets in the U.S. Once on a rail tank car, crude oil can be delivered anywhere with an unloading facility.*
- ***Diluent:*** *Less or no diluent is required when transporting bitumen in rail tank cars, representing a significant cost savings in diluent costs. However, producers have continued to transport DilBit because raw bitumen can become too viscous as a result of cold temperatures en route which may lead to longer unloading times as the bitumen would then need to be heated to flowing temperatures.*
- ***Scalability:*** *Producers have the flexibility to adjust the volumes being shipped with manifest trains. Unit trains provide economies of scale but require larger volumes to be shipped. Manifest trains are individual cars or small groups of cars, and need to wait for additional cars to collect together before being shipped to one or multiple destinations. Unit trains are a group of rail tank cars, typically 70 to120 rail tank cars that move from one destination directly to another. New loop track uploading facilities are being standardized and are typically being built to accommodate 120 cars.*
- ***Product integrity:*** *Commodity isolation in separate rail tank cars results in no loss of quality at destination. The crude oil loaded is not mixed with other grades of crude during transportation.*
- ***Low Capital requirements:*** *Typical costs to build unit train terminals range between $30 to $50 million with a capital payout of 5 years or less. unit. A train loading terminal can be constructed in about 12 months.*

Figure 4.3 North American Rail Network



Source: Rail Association of Canada

Rail Quick Facts

- Rail tank car capacity carrying light oil: 600 to 700 bbls
- Rail tank car capacity carrying heavy oil: 500 to 525 bbls
- RailBit and raw bitumen is transported in coiled and insulated rail tank 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

Pipelines are the most efficient means of connecting large supply basins to large markets areas. However, in the absence of adequate capacity in Western Canada, rail transport is expected to continue to rise due to the protracted regulatory processes for new pipelines and other uncertainties. There can be long-term viability with this mode of transportation as there are also a number of benefits associated with this mode of transportation, including the flexibility to move to different markets to respond to demand (Figure 4.3).

Western Canada Loading Capacity

In Canada, with respect to crude oil, the rail industry is evolving from a manifest system, in which trains might have to make multiple stops to deliver different products, to a unit system, in which trains go directly from the point of origin to the point of destination. Most of the large scale facilities that can load a unit train will be moving heavy oil, DilBit, RailBit or raw (undiluted) bitumen. Unit trains are more efficient because the need for switching of rail tank cars in intermediate yards is eliminated, making the overall duration of a given trip much shorter.

The level of transportation of crude oil by rail in Canada was almost 200,000 b/d by the end of 2013. Several large unit train loading facilities have been announced for Western Canada that could be operational by the end of 2015. In addition, there is the potential for future additional phases to these projects that would add further to capacity.

At the beginning of 2013, the rail loading capacity originating in Western Canada was only about 180,000 b/d. As a result of a number of new facilities and minor expansions coming into service throughout 2013, the capacity has now increased to 300,000 b/d.

Figure 4.4 shows all the major existing and proposed rail terminals for uploading crude in Western Canada. By the end of 2015, western Canadian rail uploading capacity for crude oil is expected to exceed 1.0 million b/d. Several proposed facilities can be further expanded beyond the initial stated capacity so it is conceivable that rail capacity could be expandable to 1.4 million b/d.