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OF PETROLEUM PRODUCERS

Canada's Oil and Natural Gas Producers

Crude Oil

Forecast, Markets & Transportation



June 2015



On Cover:

Top Left: Crude by Rail tank car- photo courtesy of Altex Energy

Middle Left: NCRA refinery at McPherson, KS - photo courtesy of NCRA

Middle Right: Seaway Pipeline construction - photo courtesy of Enbridge

Bottom: Kinosis *in situ* project - photo courtesy of Nexen

Back Cover: Long Lake - photo courtesy of Nexen

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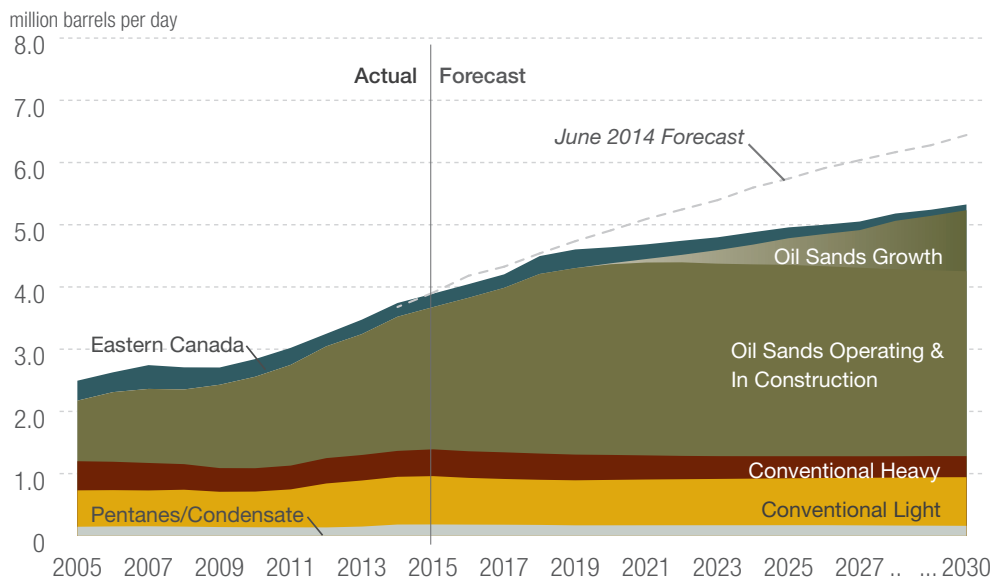
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EXECUTIVE SUMMARY

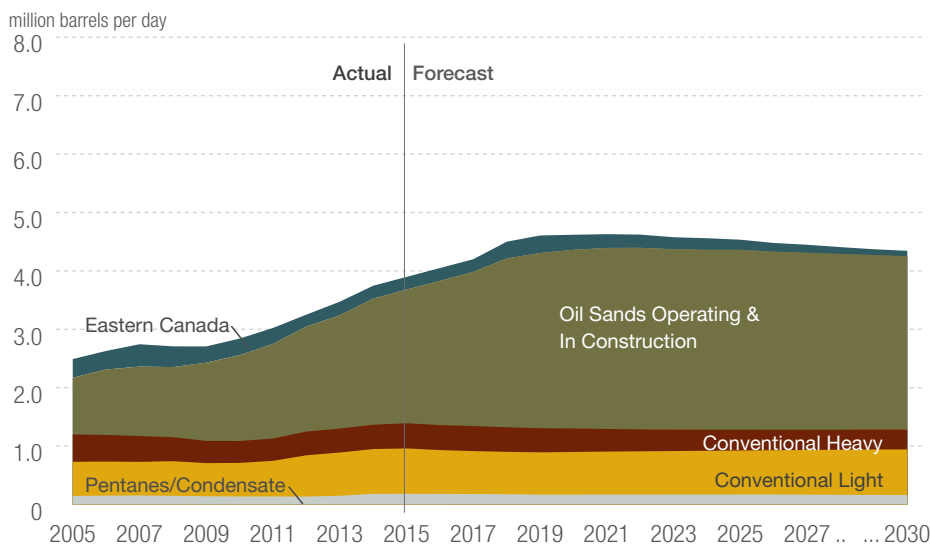
The Canadian crude oil industry is facing risks on multiple fronts in a market transformed by increased global crude oil supplies resulting in lower oil prices. These market forces are the primary driver of our revised outlook. Lower oil prices have challenged project economics and reduced capital spending intentions. These constraints have dampened the outlook for future production growth. Against this changed backdrop, highlights of this year's outlook are:

- Total oil production continues to grow but at a slower pace than previously anticipated.
- Total Canadian production grows from 3.7 million b/d in 2014 up to 5.3 million b/d in 2030, which is 1.1 million b/d lower than last year's forecast.
- Market diversity and access is still required to the U.S. Gulf Coast, the U.S. Midwest and Eastern Canada in North America. International interest in accessing Canadian crude oil is also increasing as several test cargoes were shipped to global markets in both Asia and Europe in 2014.
- The timely development of infrastructure to obtain market access is a continuing concern. The in-service dates for many of the pipeline projects have already been delayed and could be even further delayed due to extended regulatory processes. Transport of crude by rail has been growing in importance. The growth of rail beyond 2018 will primarily depend on the availability of pipeline capacity.

Canadian Oil Sands & Conventional Production - Operating & In Construction + Growth



Canadian Oil Sands & Conventional Production - Operating & In Construction ONLY



Crude Oil Production and Supply

Total production continues to grow but at a slower pace. Conventional crude oil production declines slightly over the forecast period and with 1.8 million b/d in oil sands growth, total Canadian crude oil production grows to 5.3 million b/d in 2030.

Given the challenge of developing a forecast in the current low oil price environment, a range is presented. Total oil production continues to grow but at a slower pace than previously anticipated and is 1.1 million b/d lower by 2030 than the June 2014 forecast. This is due to:

- Lower oil sands *in situ* ~835,000 b/d
- Lower oil sands mining ~33,000 b/d
- Lower conventional oil ~260,000 b/d

The oil sands production outlook that includes only projects that are currently operating or in construction represents the lower range outlook from the oil sands.

In the lower range outlook, total oil production grows from 3.7 million b/d in 2014 to 4.3 million b/d in 2030.

In the current uncertain global price environment companies continue to evaluate their growth plans. The difference in production from incorporating only the operating and in construction projects compared to the inclusion of additional production from projects currently at earlier development stages widens after 2020 and reaches almost 1 million b/d by 2030.

Conventional Oil

Conventional production in Western Canada is currently 1.4 million b/d and is expected to decline slightly to 1.3 million b/d by 2020. Of these volumes, condensate and pentanes production comprise 182,000 b/d and are expected to decline to 161,000 b/d by 2030.

Conventional oil well drilling activity is expected to decline substantially in the near-term in 2015 and 2016. Although some recovery in drilling activity has been incorporated in the latter years, there is significant uncertainty surrounding the timing.

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 2015 outlook for oil sands reflects an average annual growth of 168,000 b/d through to 2019. During the last decade of the outlook, the average annual pace from 2020 to 2030 declines to approximately 86,000 b/d.

In 2014, 2.2 million b/d were produced from the oil sands of which 912,000 b/d was from mining and 1.2 million b/d from *in situ* projects. Looking ahead to 2030, mining production is forecast to reach at least 1.4 million b/d in 2030 from projects that are operating or in construction and up to 1.6 million b/d with the additional growth forecast. *In situ* production is forecast to reach at least 1.6 million b/d from the lower range and up to 2.4 million b/d with the forecast growth.

Eastern Canada

In 2014, Eastern Canada accounted for about 6 per cent, or 220,000 b/d of total Canadian crude oil production. The Hebron project is scheduled to start operations in 2017 and provide new volumes. By 2030, production is forecast to gradually decline to around 92,000 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 crude oil.

Canadian Crude Oil Production

<i>million b/d</i>	2014	2015	2020	2025	2030
Total* Canada	3.74	3.89	4.64	4.96	5.33
Eastern Canada	0.22	0.22	0.26	0.17	0.09
Western Canada	1.37	1.39	1.30	1.28	1.28
Conventional (including condensate)					
Oil Sands					
Oil Sands Operating & In Construction	2.16	2.29	3.07	3.08	2.97
+ Oil Sands Additional Growth	-	-	+0.01	+0.43	+0.98
Oil Sands Operating & In Construction with Growth	2.16	2.29	3.08	3.51	3.95
Western Canada	3.52	3.68	4.38	4.78	5.23

*Totals may not add up due to rounding.

Crude Oil Markets

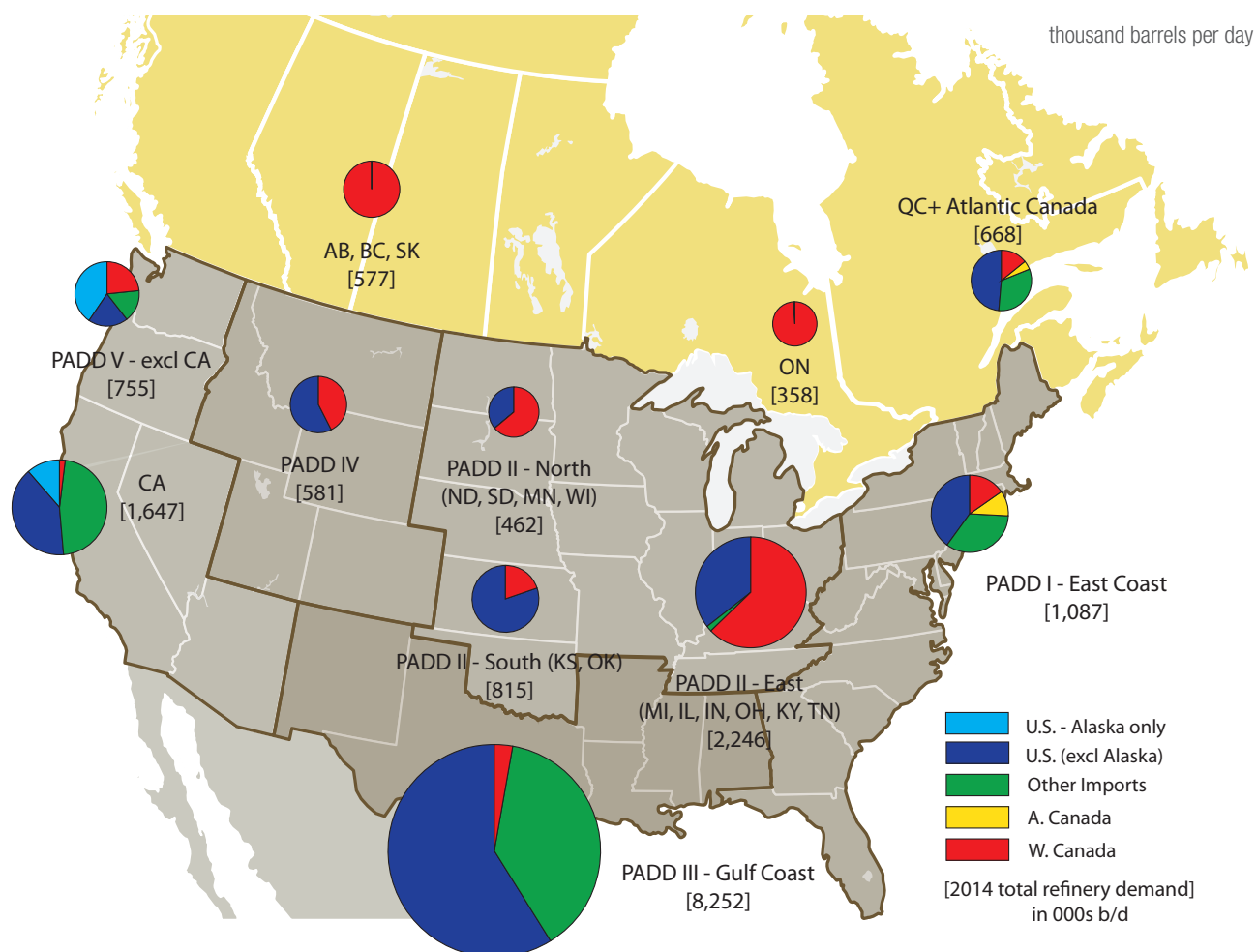
International markets are showing interest in growing Canadian supplies.

Market diversity and corresponding expanded transportation capacity remain key issues associated with this latest outlook. Canadian production requires additional tidewater access in order to reach global markets and even some prospective North American markets, including California.

Eastern Canada and the Gulf Coast represent the greatest opportunity for expanded markets in North America for Canadian crude oil production. The U.S. East Coast holds limited expansion opportunities due to their primarily light crude oil requirements that will likely be increasingly satisfied through growing U.S. domestic production. The larger U.S. Midwest market is already well supplied with western Canadian and domestic U.S. supplies.

Growing supplies of western Canadian production must be transported to tidewater if it is to ultimately reach international markets.

2014 Canada and U.S. Crude Oil Demand by Market Region



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

Eastern Canada

Refineries in Québec and Atlantic Canada currently import 77 per cent of their crude oil feedstock requirements. This translates to a potential 500,000 b/d domestic market opportunity for Canadian supplies, particularly conventional light and upgraded light crude oil. However, in 2014, imports from the U.S. more than doubled and accounted for 60 per cent of Canada's foreign imports. These volumes were transported by rail and tanker. 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 over 8 million b/d of crude oil in 2014, including over 2 million b/d of foreign heavy oil imports. Canadian producers are displacing some of these imported volumes and are forecast to supply at least 468,000 b/d to this market by 2020. This is about double the 235,000 b/d that is currently supplied.

The U.S. Midwest will remain Canada's largest export market. In 2014, Canadian producers supplied 1.9 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 190,000 b/d to reach 2.1 million b/d by 2020.

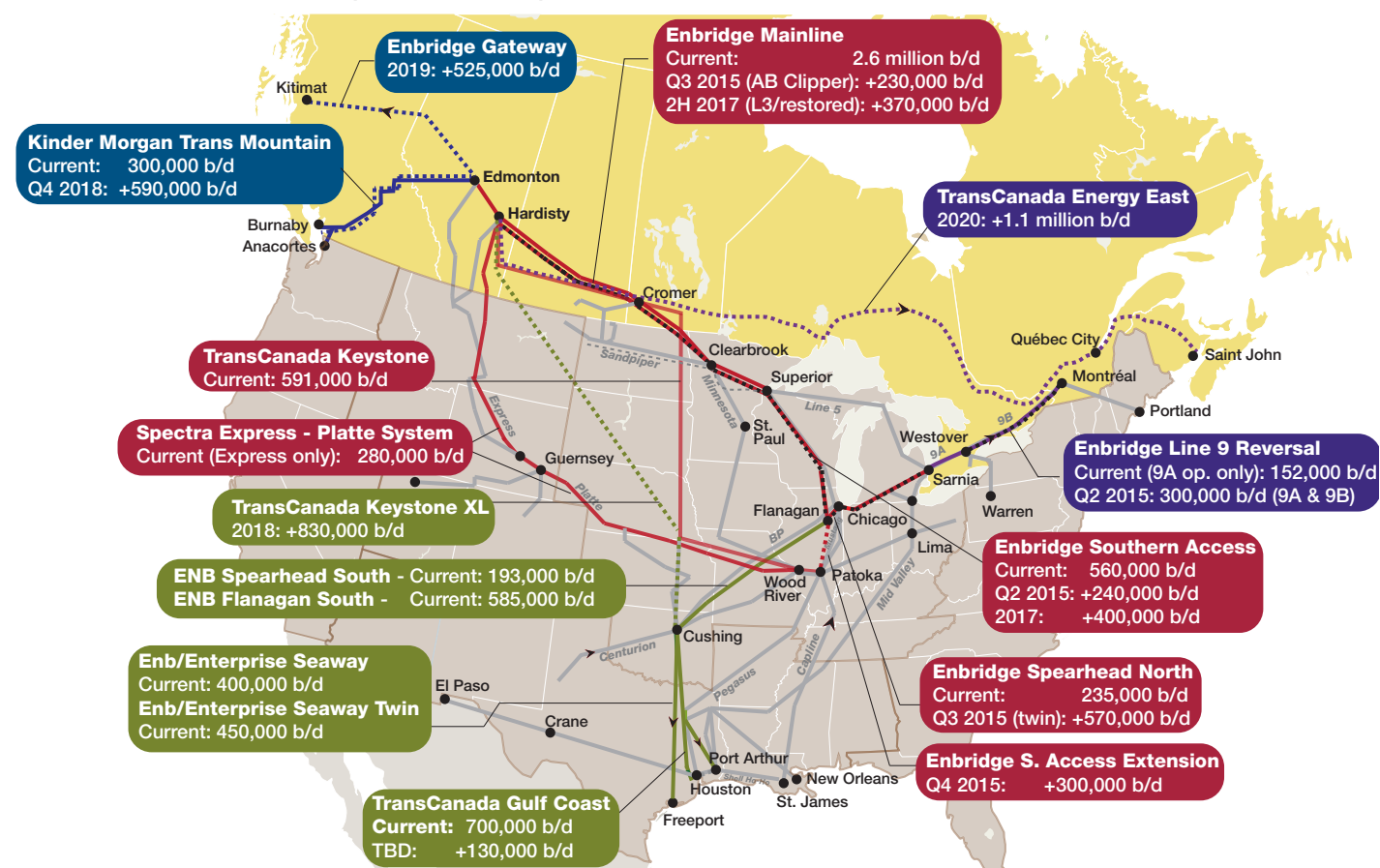
Refineries in Washington and California need to replace their declining traditional sources of supply from Alaska. These refineries are expected to increase current demand for western Canadian crude oil from 211,000 b/d to 391,000 b/d. Demand for western Canadian crude oil from U.S. East Coast refineries is not expected to grow given 2014 demand of 167,000 b/d and the survey indicating 2020 demand will fall to 133,000 b/d.

World

Currently crude oil from Western Canada has limited access to tidewater and hence to global crude oil markets. However, there is growing interest in Canada's crude oil supply in both Asia and Europe. In 2014, Statistics Canada reported shipments of Canadian crude oil destined for Italy, United Kingdom, Chile, Norway, Bahamas, France, Ireland, Spain and India. China and India have huge potential as markets for Canadian crude oil as they currently have the fastest growing demand for crude 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 6.6 million b/d; going from 10.3 million b/d in 2014 to 16.9 million b/d by 2030.

Canadian & U.S. Crude Oil Pipelines and Proposals



Crude Oil Transportation

Pipeline projects to the East, West and South are being developed and are all needed to provide sufficient market diversification to western Canadian producers.

Even with this lower growth forecast, an expansion of the existing transportation infrastructure is needed to connect growing crude oil supply from Western Canada to new markets. Pipelines are the primary mode of transportation for long term movements of crude oil but the protracted regulatory processes continues to present a number of challenges. Delays in startup timing are providing the impetus for additional capacity from railways in the transport mix to complement pipelines transport.

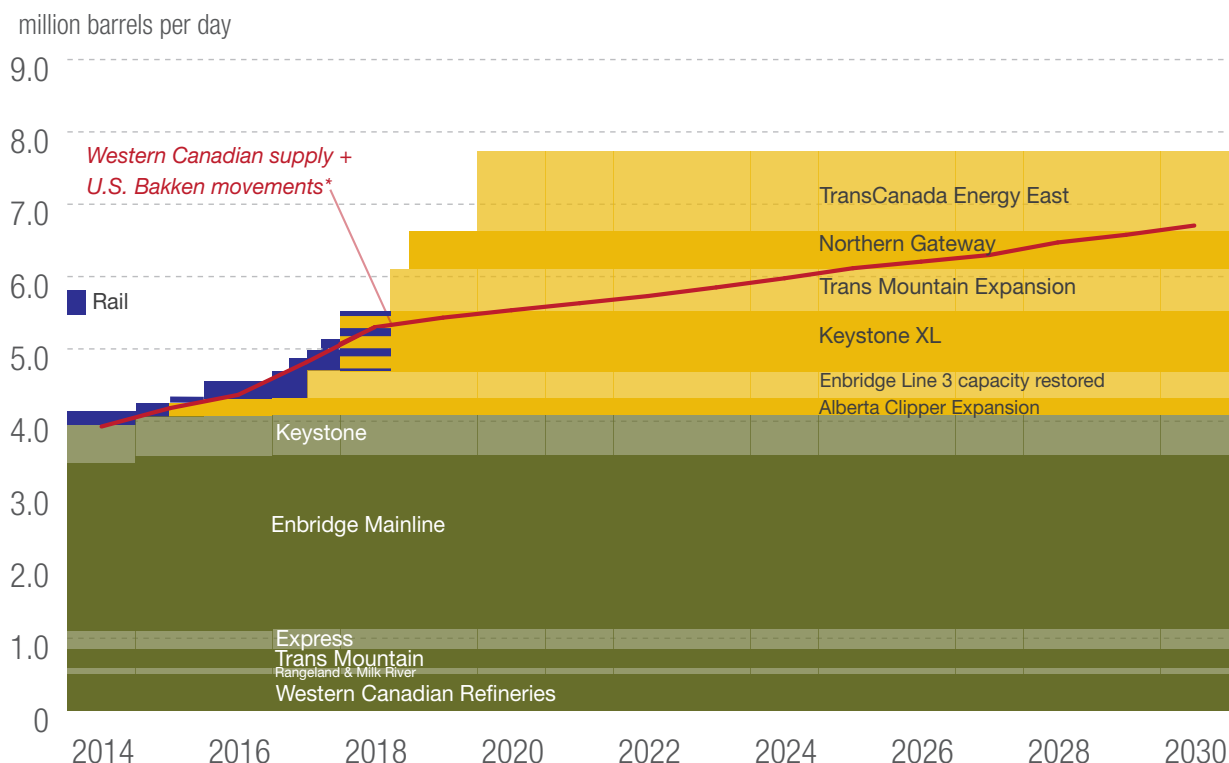
The graph below shows the existing and proposed takeaway capacity exiting the WCSB versus forecasted crude oil supply movements. Rail has been supplying increased transportation capacity. The purple represents the current and growing rail throughput that could occur until 2018. The forecasted supply movements was developed by coupling CAPP's latest supply forecast of western Canadian production with U.S. Bakken volumes that would utilize a portion of the pipeline capacity that exits Western Canada.

The proposed pipeline projects are stacked in order of the reported timing of the various individual projects. It should not be interpreted as CAPP's view of the likelihood of one project proceeding faster than another. The Keystone XL project would offer connections to the U.S. Gulf Coast refineries. The Trans Mountain Expansion and Northern Gateway projects would provide access to the West Coast and allow deliveries to Asian markets while TransCanada Energy East would provide access the East Coast markets in Canada and the U.S. and allow deliveries to be made to European markets.

These projects target three different markets and as such, all will be needed to provide western Canadian producers with a level of market diversification that would allow Canada to achieve the maximum value for its resources. Increasing market optionality is of vital importance to companies considering investing large amounts of capital in order to realize the enormous resource potential that Western Canada holds. It should be noted that the announced timing for all of the pipeline proposals have been delayed by the proponents from the dates reported last year. This reflects the challenges associated with large linear infrastructure projects.

In 2014, crude by rail volumes averaged 185,000 b/d. Crude by rail continues to be used as a complement to pipeline transportation with volumes moving by rail anticipated to continue to grow through to 2018. Beyond that rail use will be impacted by the timing of proposed pipeline projects.

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



CAPP's *Crude Oil Forecast, Markets & Transportation* report is typically published around the middle of each year. The crude oil supply outlook for Canada is provided in conjunction with an examination of the potential demand for this production in various markets. There is also an update on the existing transportation infrastructure and proposed transportation projects to serve these markets. As such, the report endeavors to meet the growing need for a timely reference document that can be used by industry, government, media, the financial community, environmental groups and the general public alike.

The 2015 CAPP crude oil forecast provides the outlook for Canadian production from 2015 to 2030. It covers conventional oil, oil sands and offshore production. The oil sands forecast is based on the amalgamated results of the producers' latest reported data on their individual oil sands projects. The market demand forecast reflects an unadjusted survey of North American refiners' future demand for western Canadian crude oil until 2020.

The Canadian crude oil industry is managing risks on multiple fronts in an environment transformed by lower oil prices. During the latter part of 2014, the industry witnessed a rapid drop in oil prices. The benchmark WTI crude oil spot price dropped from a peak of over US\$100 per barrel in June 2014 to below US\$55 per barrel in December. From January to April 2015, the oil price averaged around \$50 per barrel. Lower oil prices are challenging project economics. Against this changed backdrop, CAPP's latest Canadian oil production outlook anticipates that total oil production continues to grow but at a slower pace and is 1.1 million b/d lower by 2030 than was forecast a year ago.

Canadian crude oil production growth remains driven primarily by production from oil sands resources, which comprise over 97 per cent of Canada's crude oil reserves. CAPP's estimate of industry capital spending for oil sands development is C\$23 billion for 2015, which is C\$10 billion lower from the estimated expenditure in 2014. Conventional production declines slightly through the forecast, whereas the declines in production from offshore Eastern Canada commence in 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 was considered in determining the pace of development in future project stages. 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 or transportation infrastructure.

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 and decline rates.

1.2 Market Demand Outlook Methodology

As in the past, CAPP did not make any adjustments to the data submitted by refiners regarding their expectation of future demand for Canadian crude oil beyond checking for potential errors. Where possible, EIA data was used or adjusted to complete gaps in the survey data for actual demand in 2014 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)
4. Light Sweet Synthetic (Upgraded Light)

The following crude types and definitions apply to the historical data of foreign imports presented in the source of supply pie charts in this section of the report:

- 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

In this publication, CAPP reports the timing of the proposed pipeline and rail projects based on information released by the project proponents. The project-review timelines within the regulatory process can be lengthier than originally anticipated and represents a significant factor that impacts the final in-service date of these projects.

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



Oil is one of the most important sources of energy in the world, accounting for over 30 per cent of the total primary energy consumption. Globally, Canada is the 5th largest producer of oil, according to the U.S. Department of Energy, Energy Information Administration (EIA). The Oil & Gas Journal reports Canada's proven oil reserves at 173 billion barrels; the world's third largest reserves after Venezuela and Saudi Arabia. Notably, the oil sands that are located in the province of Alberta hold 167 billion barrels of these reserves.

The strategic development of these resources is important to both industry and the Canadian economy. In the current low oil price environment, it is vitally important to encourage investment in the oil industry. It provides the foundation for security of supply and jobs. The impact of the lower world oil prices on the Canadian industry has been mitigated somewhat by the lower Canadian dollar and lower discounts for Canadian crude oil. However, the industry continues to manage long term challenges including volatile price differentials and increasing costs related to operations and improving market access.

2.1 Canadian Crude Oil Production

In 2014, Canada produced 3.7 million b/d of crude oil, an increase of 267,000 b/d or 8 per cent over 2013 levels. Production is expected to continue to grow throughout the forecast period. Western Canada produced 3.5 million b/d, of which 2.2 million b/d came from the oil sands and 1.4 million b/d came from conventional resources. About 220,000 b/d originated in Eastern Canada.

This year, we have provided additional detail underlying our forecast by breaking out the component of the forecast for oil sands production that includes only projects currently "Operating" or "In Construction". In the current uncertain global price environment companies continue to evaluate their growth plans. Table 2.1 shows the forecast for total Canadian production and its breakdown between Eastern and Western Canada.

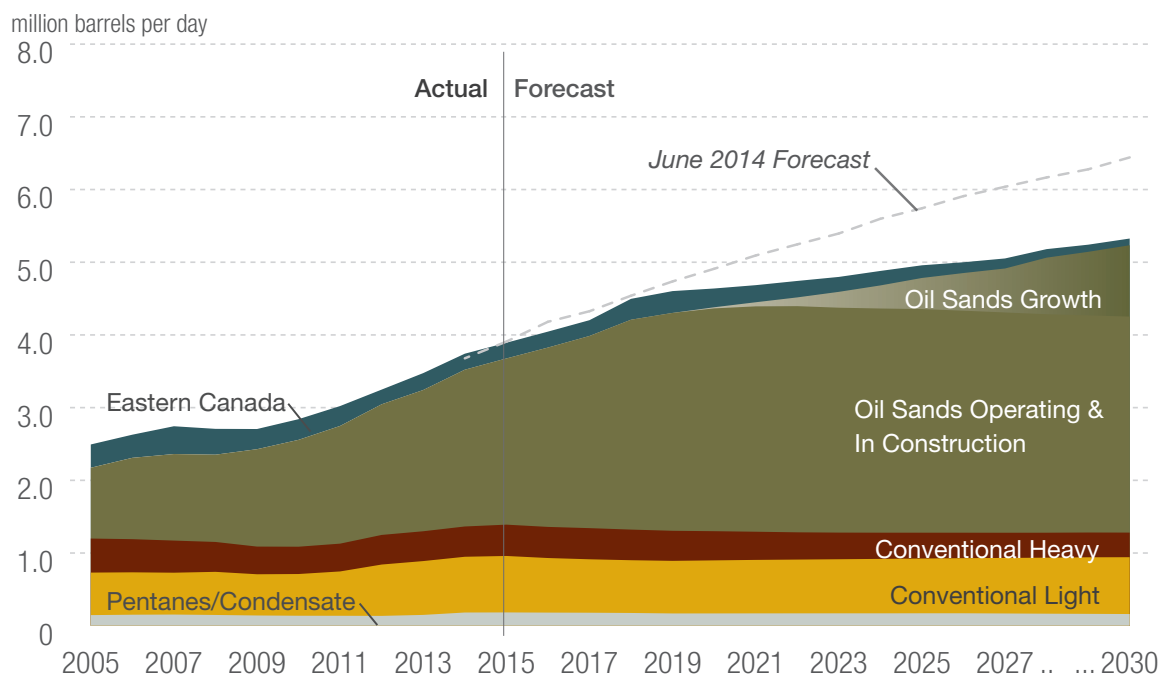
Table 2.1 Canadian Crude Oil Production

<i>million b/d</i>	2014	2015	2020	2025	2030
Total* Canada	3.74	3.89	4.64	4.96	5.33
Eastern Canada	0.22	0.22	0.26	0.17	0.09
Western Canada					
Operating & In Construction	3.52	3.68	4.37	4.36	4.25
+ Western Canada Growth	-	-	+0.01	+0.43	+0.98
Western Canada	3.52	3.68	4.38	4.78	5.23

*Totals may not add up due to rounding.

Figure 2.1 shows the total Canadian production forecast. Conventional production from Western Canada is expected to decline slightly throughout the forecast and falls to 1.3 million b/d by 2030. Oil sands production will drive the overall increase in production, which is expected to grow on average by 168,000 b/d for the next 5 years. This rate of growth is similar to that exhibited in the past 5 years. However, this rate of growth slows by almost a half for the last decade of the forecast as oil sands production is anticipated to reach almost 4.0 million b/d by the end of the forecast period in 2030.

Figure 2.1 Canadian Oil Sands & Conventional Production



2.2 Eastern Canadian Crude Oil Production

There are small volumes of crude oil produced in Ontario and New Brunswick. In terms of development in other provinces, the Québec government supported preliminary oil exploration work on Anticosti Island in 2014. It was recently reported that oil was discovered in the Gaspé region of Québec.

However, the primary source of Eastern Canada's crude oil production is from projects located offshore 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 White Rose Extensions).

Development drilling continued on the first production wells for the South White Rose Extension with first oil anticipated in mid-2015. The final investment decision for the West White Rose Extension project was deferred by the operator in December 2014 as part of the overall reduction in capital investment and is not included in CAPP's forecast.

Drilling of the Hibernia-formation well at the North Amethyst field is scheduled to resume after the first two South White Rose production wells have been brought online in mid-year. First production from the well is expected in the third quarter of 2015. A planned sidetrack of the first appraisal well was completed and drilling of the second well began in the first quarter of 2015. First oil from Hebron, the fourth major project, is expected around the end of 2017.

In 2014, eastern Canadian production declined to 220,000 b/d, which translates to a 5 per cent decrease from the previous year. At the end of the forecast period, production is expected to decline to 92,000 b/d by 2030. Overall, there is little change compared to CAPP's 2014 forecast.

Future production could be higher than forecast as potential production from the Flemish Pass Basin have not yet been incorporated in CAPP's forecast due to the early stage of evaluation. The Bay du Nord discovery area 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 originates from both conventional and oil sands sources (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.

Similar to CAPP's 2014 report, production is expected to grow by 156,000 b/d until 2020, which effectively maintains a similar growth rate that has been exhibited for the past five years. This is primarily due to commitments to capital investments already underway for upcoming oil sands projects. From 2020 to 2030, however, this rate of growth is expected to slow to 85,000 b/d year-over year until 2030. At the end of the outlook period, western Canadian oil production is 1.1 million b/d lower than forecast last year but still reaches 5.2 million b/d in 2030.

Conventional production is forecast to contribute 1.3 million b/d to the total output on average over the forecast period. Compared to last year's forecast, conventional production is 260,000 b/d lower by 2030; the majority of this decline reflects the significant drop in the number of wells drilled in the short-term given the low oil price environment.

Table 2.2 Western Canadian Crude Oil Production

<i>million b/d</i>	2014	2015	2020	2025	2030
Western Canada	3.52	3.68	4.38	4.78	5.23
Conventional (including pentanes/ condensate)	1.37	1.39	1.30	1.28	1.28
Oil Sands Operating & In Construction	2.16	2.29	3.07	3.08	2.97
+ Oil Sands Growth	-	-	+0.01	+0.43	+0.98
Oil sands (bitumen & upgraded)	2.16	2.29	3.08	3.50	3.95

*Totals may not add up due to rounding.

2.3.1 Conventional Crude Oil Production

In 2014, conventional production, including condensates, increased by 66,000 b/d to 1.4 million b/d. Although there has been a year-over-year upward trend in conventional production since 2010, it is expected to return to a slow decline starting in 2016. 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, including condensates, is forecast to comprise 74 per cent of total conventional production.

Most of the condensate production in Canada comes from Alberta and British Columbia and is primarily recovered from natural gas wells. Notably, condensate production, a subset of total conventional production, increased by 33,000 b/d in 2014 or 22 per cent, growing from 149,000 b/d to 182,000 b/d. Condensate production from the liquids-rich Montney play and emerging Duvernay play rose with higher drilling activity but due to lower oil and gas prices, drilling activity is expected to decline in the near term. However, overall condensate production is forecast to only decline slightly to 161,000 by 2030.

Alberta

Alberta is well-known for its oil sands resources but it also accounts for about half of Western Canada's conventional oil production, excluding condensates. In addition, the province is the source of 84 per cent of the condensate production in Western Canada. In 2014, Alberta's conventional light crude oil production, increased by 2 per cent compared to 2013, to 440,000 b/d. In contrast, conventional heavy crude oil production, decreased by 2 per cent to 150,000 b/d. Overall, total conventional production increased by 1 per cent to 590,000 b/d. The outlook calls for a slight decline throughout the forecast to 524,000 b/d by 2030. The province's condensate/pentanes plus production increased by 21 per cent to 153,000 b/d in 2014.

Saskatchewan

Saskatchewan is the second largest oil producing province in Canada. A growth in conventional light oil production over the past three years, continued with an 8 per cent increase in 2014 with production reaching 248,000 b/d. There was also a 4 per cent growth in conventional heavy oil production so that this production rose to 267,000 b/d. The total conventional production in Saskatchewan grew by 6 per cent or 28,000 b/d to reach 514,000 b/d. On average, Saskatchewan conventional production is expected to contribute 536,000 b/d during the outlook.

Manitoba, British Columbia, NWT

Manitoba accounts for 4 per cent of the total conventional production from Western Canada excluding condensates. Current production of 47,000 b/d is forecast to decline gradually through the outlook to 27,000 b/d by 2030.

British Columbia is the second largest provincial source of condensate production after Alberta, accounting for 15 per cent of total condensate production in Western Canada. The province also accounts for 2 per cent of total western Canadian conventional production.

Little production currently comes from the Northwest Territories (NWT); however, there has been some investment attracted to the Sahtu region, one of North America's oldest fields. The NEB and the Northwest Territories Geological Survey released its first publicly available assessment of the unconventional oil-in-place resources for the Bluefish Shale and Canol Shale in the NWT, in May 2015. The report stated that if only 1 per cent of the oil-in-place assessed for Canol Shale could be recovered, it would represent a marketable resource of 1.45 billion barrels.

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).

Figure 2.2 Western Canada Conventional Production

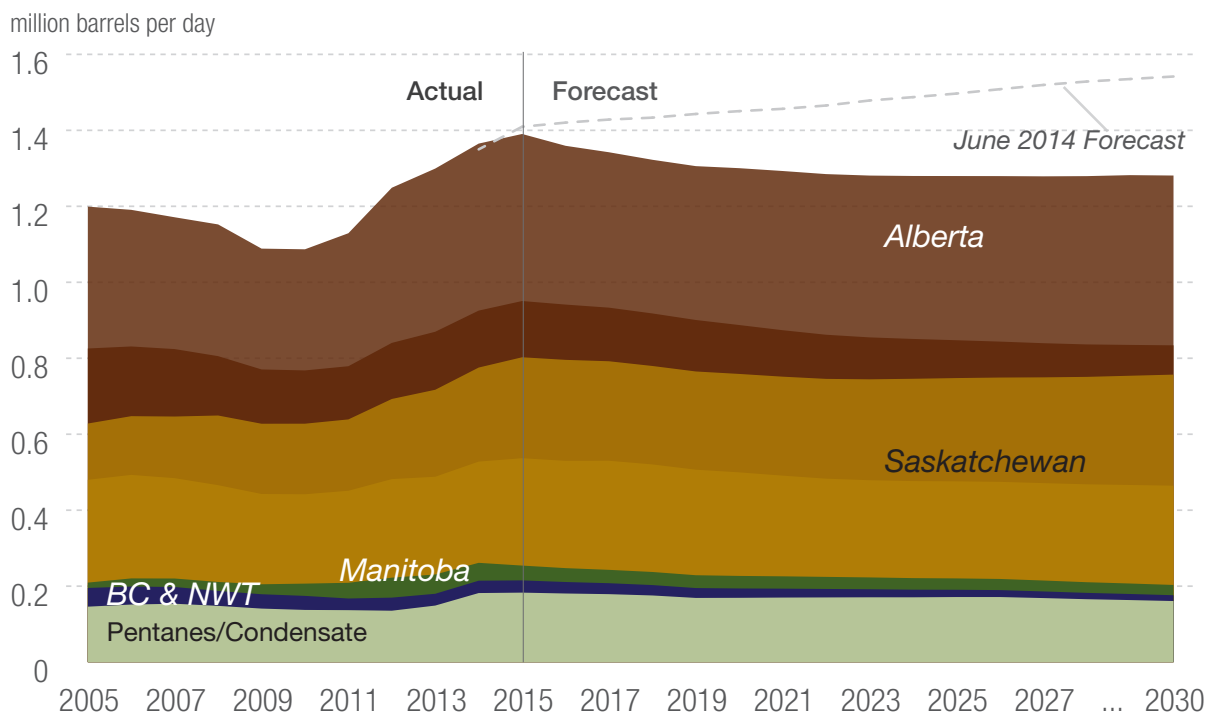


Figure 2.3 Oil Sands Regions



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. The term is used in reference to both primary development, which uses methods similar to conventional crude oil production, and enhanced recovery techniques - the main methods being cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD). As such the resources are accessed via a combination of steam injection wells to reduce the viscosity of the bitumen and recovery or production wells. Of the remaining established oil sands reserves in Alberta, 33 billion barrels or 20 per cent is considered recoverable by mining and 135 billion barrels or 80 per cent can be recovered using *in situ* techniques.

The growth reflected in this latest oil sands forecast from 2015 to 2019 is relatively unchanged from CAPP’s 2014 forecast as it is mostly comprised of the production from 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 2020 to 2030, oil sands production is lower by 117,000 b/d in 2020 and up to 857,000 b/d lower by 2030 than the previous year forecast due to a lower outlook for *in situ* production.

In 2014, oil sands production totaled 2.2 million b/d. Of these volumes, 1.2 million b/d were recovered by *in situ* techniques. Mining production is forecast to grow up to 1.6 million b/d by 2030. Most of the growth is expected from *in situ* production, which is forecast to grow to 2.4 million b/d by 2030 (Table 2.3).

Figure 2.4 Western Canada Oil Sands (Operating & In Construction) & Conventional Production

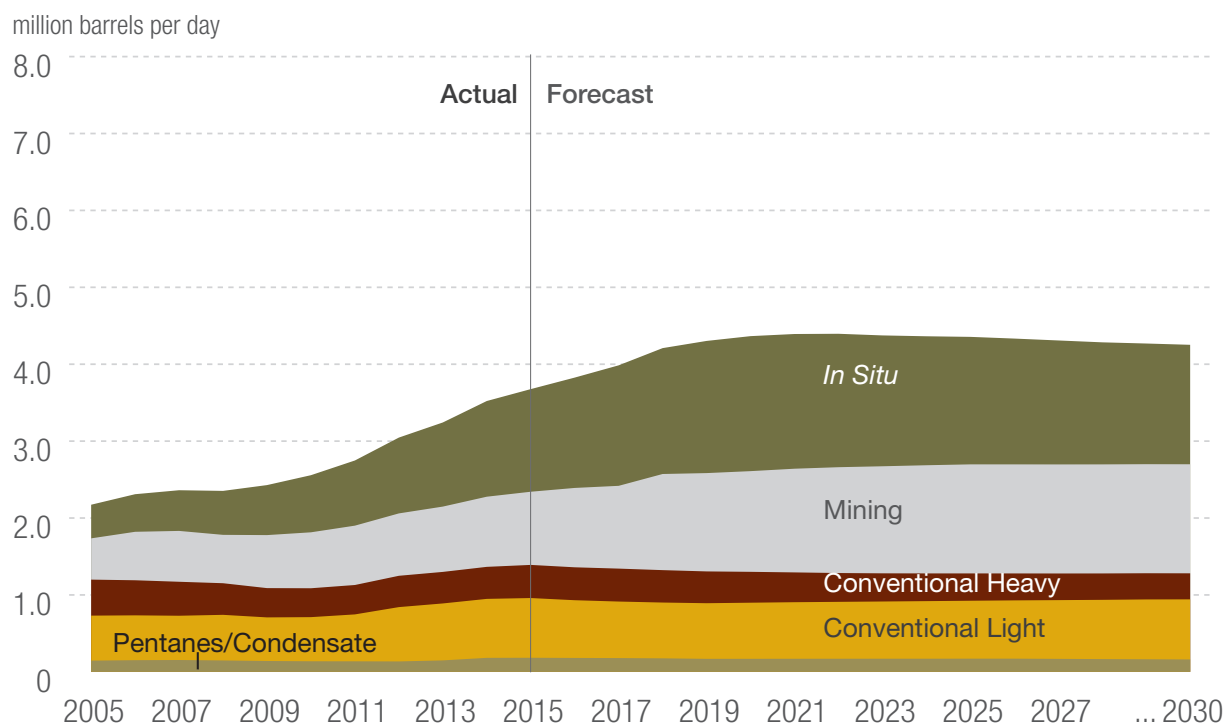


Table 2.3 Oil Sands Production

million b/d	2014	2015	2020	2025	2030
Total*	2.16	2.29	3.08	3.50	3.95
Mining (Operating & In Construction)	0.91	0.95	1.31	1.42	1.42
+ Mining Growth	-	-	-	-	+0.16
Mining	0.91	0.95	1.31	1.42	1.58
In Situ (Operating & In Construction)	1.24	1.33	1.76	1.66	1.55
+ In Situ Growth	-	-	+0.01	+0.43	+0.82
In Situ	1.24	1.33	1.77	2.09	2.38

*Total may not add up due to rounding.

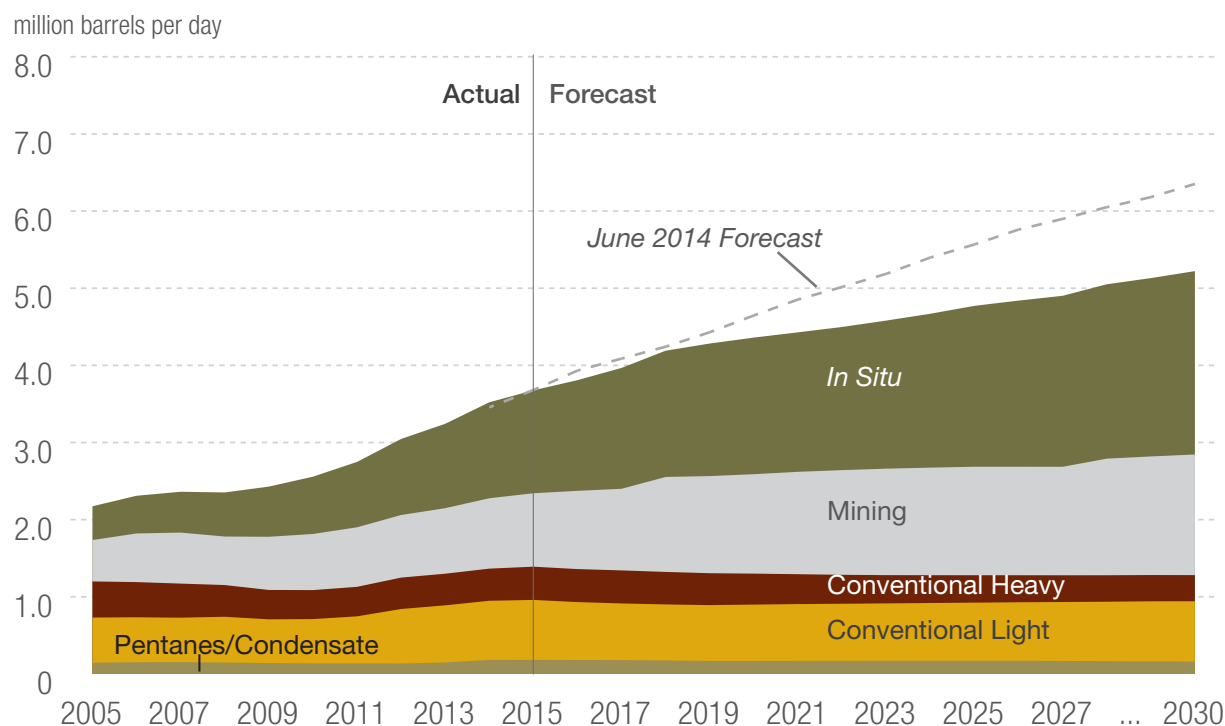
Production volumes from oil sands are typically reported using the upgraded crude oil volumes from integrated projects instead of the raw bitumen volumes processed by these projects. The yield losses associated with upgraded bitumen volumes from non-integrated producers have been accounted for in the supply volumes that are discussed in the next section of this report. Production from oil sands currently accounts for 61 per cent of Western Canada's total crude oil production. In this forecast, oil sands production of 2.2 million b/d in 2014 increases by 1 million b/d in eight years and reaches 3.9 million b/d by 2030 (Figure 2.4). The oil sands forecast in 2030, is approximately 857,000 b/d lower than forecast in the last report.

Refer to Appendix A.1 for detailed production data.

Currently, Nexen's Long Lake project is the only *in situ* project coupled with upgrading facilities. All mined bitumen projects, with the exception of the Imperial's Kearl mining project, have an affiliated upgrader that transforms the mined bitumen production into upgraded light crude oil. The Kearl 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.

Existing integrated mining and upgrading projects are listed below:

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

Figure 2.5 Western Canada Oil Sands (Operating & In Construction + Growth) & Conventional Production

2.4 Western Canadian Crude Oil Supply

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 oil sands are either upgraded or blended in order to be transported or to meet optimal refinery specifications. In any event, it is these crude oil supplies that are ultimately delivered to the end-use markets and therefore most relevant to market observers.

In this report, CAPP categorizes the various crude oil types that comprise western Canadian crude oil supply into the following main categories: Conventional Light; Conventional Heavy; Upgraded Light; and Oil Sands Heavy. Oil Sands Heavy includes upgraded heavy sour crude oil, bitumen diluted with upgraded light crude oil (also known as “SynBit”) and bitumen diluted with condensate (also known as “DilBit”). Blending for DilBit differs by project but requires approximately a 70:30 bitumen to condensate ratio while the blending ratio for SynBit is approximately 50:50. Bitumen volumes transported by rail are currently relatively small. These railed volumes may be transported as raw bitumen or could use less diluent for blending (also known as “RailBit”) versus moving by pipeline.

In 2014, about 1.1 million b/d or 52 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 exclusively.

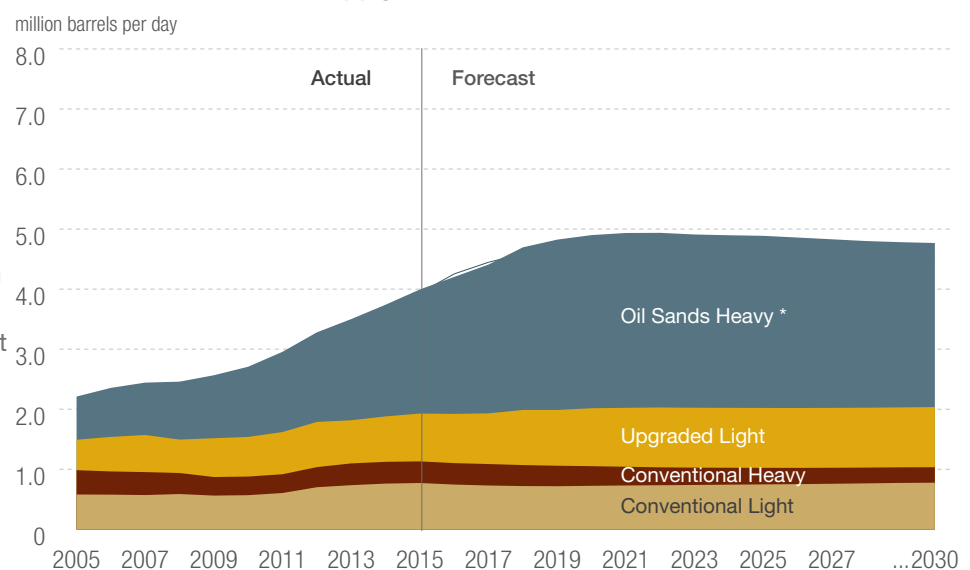
Upgraded volumes are forecast to rise to 1.6 million b/d by 2030. The bitumen upgraders located in Alberta produce a variety of upgraded products. Suncor produces synthetic light sweet crude and medium sour crudes, including diesel; Syncrude, Canadian Natural Horizon, and Nexen Long Lake produce light 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 upgrading and the need for a sustained differential between light and heavy crude oil of at least \$25 per barrel. It is difficult for a new upgrader to compete with the option of transporting heavy crude oil to existing refineries located throughout North America that have spare coking capacity and are able to refine the heavy crude slates produced in Western Canada.

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. Unblended bitumen generally cannot be moved by pipeline. Less diluent could be required when bitumen is moved by rail if it is transported in heated rail cars that lower the viscosity of the bitumen. The main source of diluent is condensate that is recovered from processing natural gas in Western Canada. This source of condensate will be insufficient to meet the blending needs associated with growing bitumen production.

In 2014, around 250,000 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.

Figure 2.6 Western Canada Oil Sands (Operating & In Construction) & Conventional Supply



The potential for bitumen to travel by rail with reduced diluent requirement has not been factored into the analysis of condensate demand. Should rail become a more significant delivery system, its corresponding impact on the required diluent volumes will be reflected in future survey results and in turn, incorporated in CAPP's future forecasts.

Table 2.4 Western Canadian Crude Oil Supply

million b/d	2014	2015	2020	2025	2030
Operating & In Construction Total*	3.74	4.00	4.90	4.89	4.77
Light	1.52	1.57	1.69	1.75	1.78
Heavy	2.22	2.43	3.21	3.14	2.99
Growth Total*	3.74	4.00	4.92	5.47	6.06
Light	1.52	1.57	1.69	1.68	1.85
Heavy	2.22	2.43	3.23	3.79	4.21

*Total may not add up due to rounding.

Table 2.4 shows the projections for total western Canadian crude oil supply. Refer to Appendix A.2 for detailed data. Light crude oil supply is projected to be relatively stable at around 1.7 million b/d on average for the outlook. Heavy crude oil supply is projected to grow from 2.2 million b/d in 2014 to almost double this at 4.2 million b/d in 2030.

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

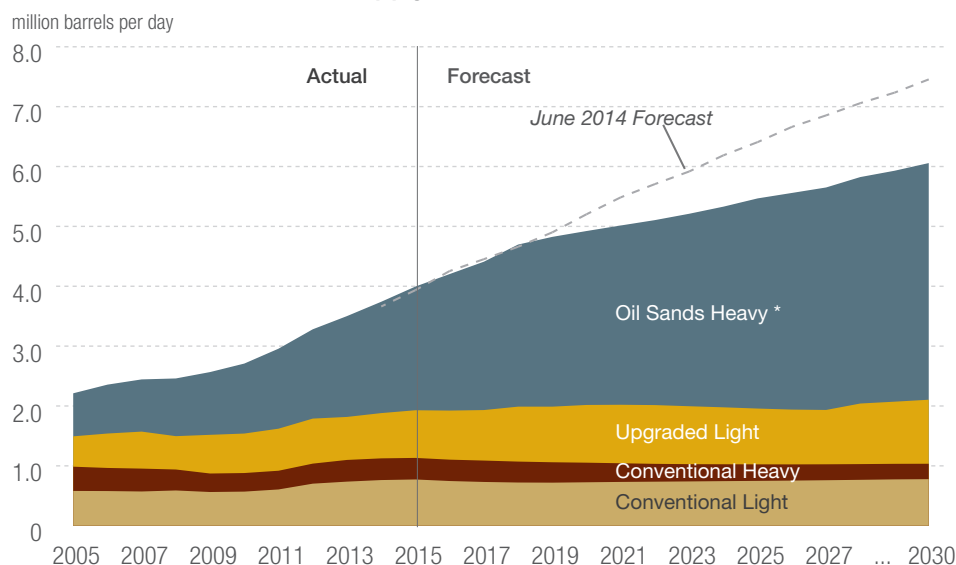
- Upgraders that process conventional heavy oil;
- Integrated mining and upgrading projects;
- Integrated *in situ* projects; and
- Off site upgraders.

Compared to the 2014 forecast, the upgraded light crude oil supply is relatively unchanged. The Oil Sands Heavy category is forecast to double from 1.9 million b/d in 2014 to 4.0 million b/d by 2030 (Figure 2.7), which is 1.4 million b/d lower than was forecasted last year.

2.5 Crude Oil Production and Supply Summary

Overall, total Canadian production is anticipated to grow from 3.7 million b/d in 2014 to 5.3 million b/d in 2030 which is 1.1 million b/d lower by 2030 than CAPP's June 2014 forecast. It reflects continued growth but at a slower pace. This reduction in future production is the combined effect of a 835,000 b/d lower forecast from *in situ* oil sands; a 21,000 b/d lower forecast from mining and a 260,000 b/d lower forecast from conventional oil. In this latest forecast, the growth in oil sands production is relatively unchanged until 2020. The existing oil sands projects and those under construction will continue to proceed but there is some uncertainty surrounding future projects. In contrast, conventional production is more sensitive to short term fluctuations in oil prices.

Figure 2.7 Western Canada Oil Sands (Operating & In Construction + Growth) & Conventional Supply



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

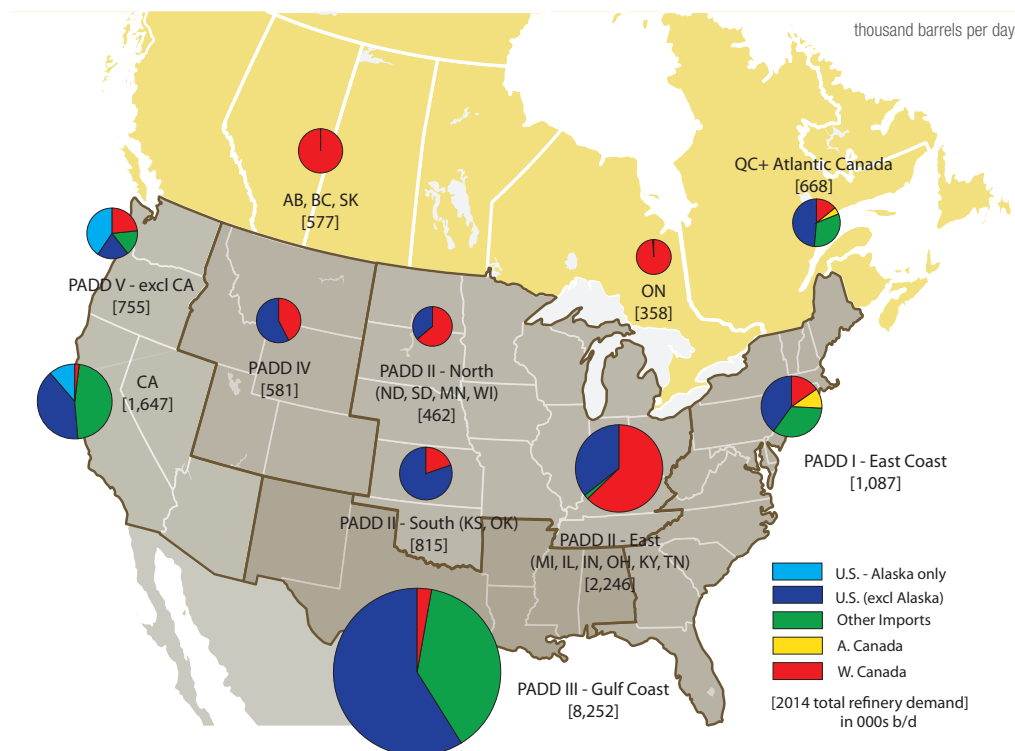
The production outlook from offshore Atlantic Canada is unchanged with stable production levels anticipated in the near-term. Long-term declines are offset by production from satellite fields. The Hebron project, expected to start in 2017 will contribute additional production. By 2030, however, production is forecast to decline to 92,000 b/d.

3 | CRUDE OIL MARKETS



Crude oil supply from Western Canada by 2020 is forecast to increase by 1.1 million b/d from current levels. This chapter investigates which markets could be served by growing Canadian crude oil supplies. Figure 3.1 shows the size of and the sources of supply for refining markets in Canada and the United States (U.S.). The area in red shows the share of a given market taken up by western Canadian crude oil. The U.S. Gulf Coast has significant heavy oil processing capacity and as such, is an ideal target market for growing supplies of western Canadian heavy crude oil supplies. In order to increase its market share in these markets, Canadian production will have to displace other sources of crude oil. Access to tidewater is needed in order for Canadian producers to serve global markets that lie beyond North America, such as Asia and Europe.

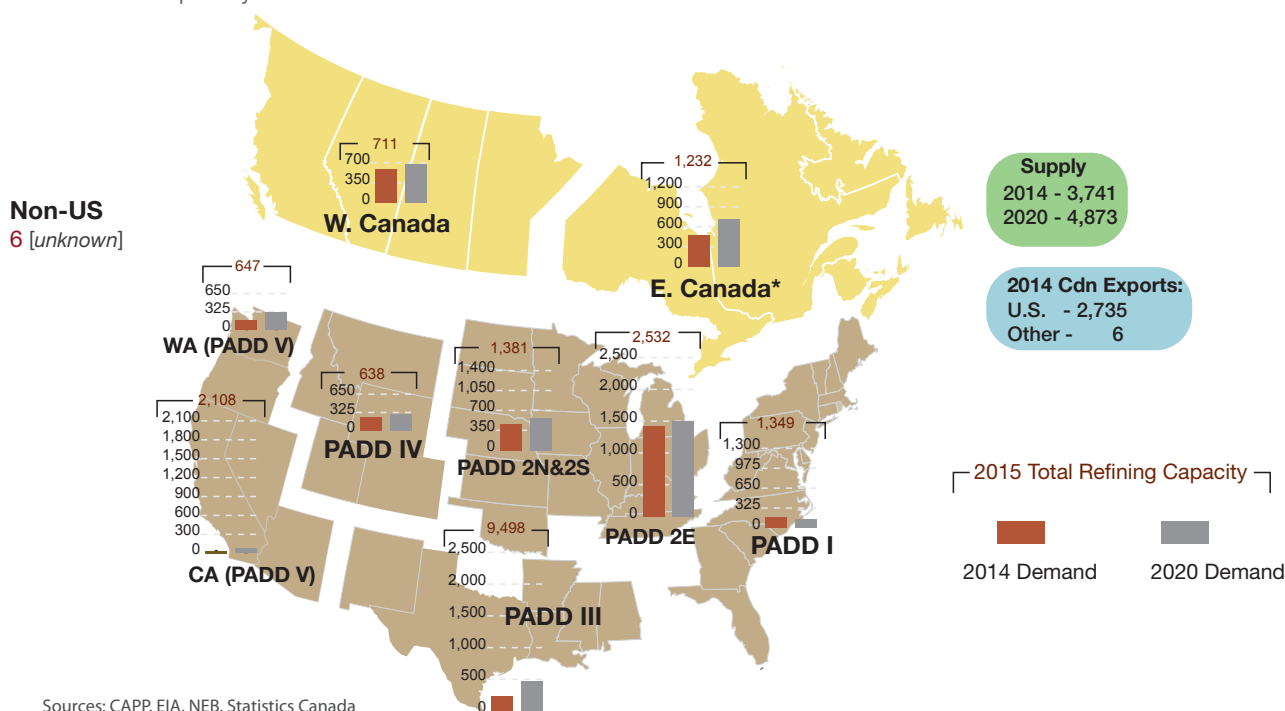
Figure 3.1 Canada and U.S. Market Demand for Crude Oil in 2014 by Source



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

Figure 3.2 Market Demand for Western Canadian Crude Oil: Actual 2014 and 2020

thousand barrels per day



* E.Canada demand for W. Canadian crude oil in 2014 consisted almost entirely of receipts from Ontario. Projected receipts in 2020 include growth from Québec and Atlantic provinces.

Note: 2014 demand does not equal available supply due to factors including inventory adjustment, timing differences, and the potential for U.S. production transiting in Canada before being refined in the U.S. being reported as Canadian exports.

About 30 per cent of the total western Canadian crude oil supply available is processed at Canadian refineries. In 2014, this was equivalent to 1.1 million b/d that was refined domestically with the remaining 70 per cent exported. Data collected by the EIA indicated that U.S. imports from Western Canada totaled 2.7 million b/d. CAPP's refiner survey results indicate that Eastern Canada, PADD III, PADD II and PADD IV could potentially absorb the forecasted growth in western Canadian supply by 2020 (Figure 3.2).

The oil pipeline network exiting Western Canada currently connects to refineries in Western Canada and Ontario. Some Canadian refineries located further east that currently lack pipeline access to continental production started using 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 1.5 million b/d by 2020 as a result of planned refinery expansions and future transportation infrastructure developments.

3.1 Canada

Canadian refineries have the capacity to process 1.9 million b/d of crude oil. About two-thirds of the crude oil processed in Canada is sourced from domestic production but this share is expected to increase as refineries in Eastern Canada gain additional access to western Canadian crude oil supplies. In 2014, Canadian refineries processed 1.0 million b/d of western Canadian crude oil and 34,000 b/d of crude oil produced in Eastern Canada. About 542,000 b/d of foreign crude oil was imported, of which, 324,000 b/d was sourced from the U.S.

3.1.1 Western Canada

Western Canada has a total refining capacity of 711,000 b/d from eight refineries. In 2014, these refineries processed 577,000 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 96,000 b/d to 673,000 b/d (Figure 3.3). The additional crude oil receipts in the future are related to a debottleneck project at the Moose Jaw plant, expansion plans at the Co-op refinery complex, which are both located in Saskatchewan, and the startup of the North West Redwater Partnership's refinery near Redwater in Sturgeon County, located about 45 km northeast of Edmonton, Alberta.

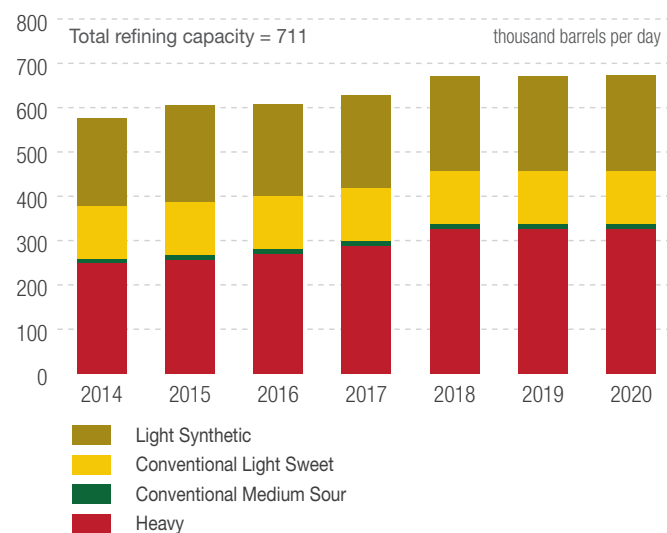
The Co-op Refinery Complex owned by Federated Co-operatives Limited (FCL) experienced a fire in December 2013 which affected the heavy feedstock demand for a significant portion of 2014. The anticipated increase in demand in 2015 relative to 2014 relates to the facility returning to normal operations.

The \$8.5 billion 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 Alberta provincial government, will supply 75 per cent of the feedstock and Canadian Natural Resources Limited will supply the rest. The project broke ground on September 20, 2013 and is scheduled to be operating by September 2017.

Gibson Energy has also announced an expansion to its Moose Jaw plant that is scheduled to be completed by November 2015.

Two new export refinery concepts in British Columbia (BC) are being developed. Kitimat Clean's refinery is proposed by newspaper publisher David Black and would be located near Kitimat, BC. The refinery would be designed to process 550,000 b/d of bitumen into 460,000 b/d of gasoline, jet fuel and diesel for transportation to Asian markets. The second refinery is being proposed by Pacific Future Energy Corp. with former politician, Stockwell Day, promoting the project. A site location decision has not been finalized. The refinery would be designed to be built in modules with the first phase able to process 200,000 b/d of bitumen.

Figure 3.3 Western Canada:
Crude Oil Receipts from Western Canada

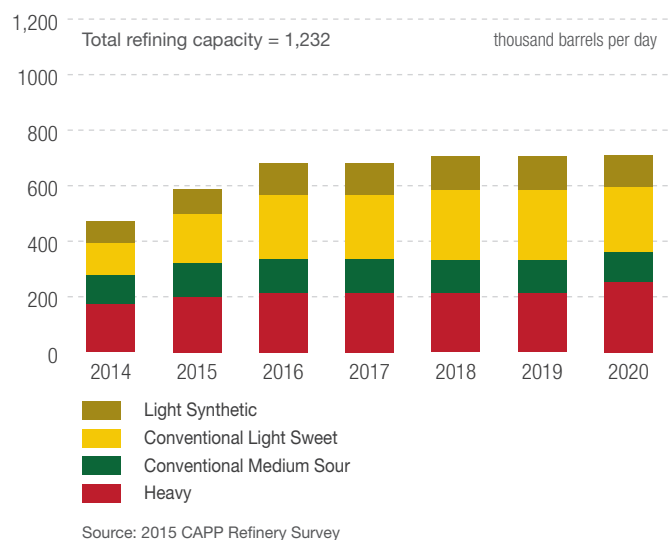


3.1.2 Eastern Canada

A total of eight refineries are located in Ontario, Québec and Atlantic Canada. These eastern Canadian refineries have a combined capacity of about 1.2 million b/d. In 2014, Western Canada supplied 472,000 b/d to this market, which was over 100,000 b/d more than that supplied in 2013. These deliveries were facilitated through the increased use of rail transportation.

Most of this production was delivered to Ontario. By 2020, overall demand for western Canadian crude oil is expected to increase by 240,000 b/d. The upcoming reversal of the Enbridge Line 9 to Montréal will provide this market with pipeline access to western Canadian crude oil. The TransCanada Energy East project also proposes to provide Canadian crude oil access to this market in 2020. (Figure 3.4).

Figure 3.4 Eastern Canada:
Crude Oil Receipts from Western Canada



Ontario

The four refineries located in Ontario have a combined refining capacity of 393,000 b/d. Most of the crude processed at the Ontario refineries is sourced from Western Canada but they also refine some foreign crude oil and crude oil transported from Atlantic Canada. In 2014, Ontario refineries processed 379,000 b/d of crude oil, which was comprised of 356,000 b/d from domestic supplies and the remainder from foreign imports.

Québec & Atlantic Provinces

The four refineries in Québec and Atlantic Canada have a combined capacity of 837,000 b/d. The crude oil processed at these refineries generally originates from either Atlantic Canada or foreign sources. Crude oil imports sourced from the U.S. have more than doubled in the last year and accounted for 60 per cent of Canada's foreign imports in 2014. Crude oil originating from the U.S. Bakken in Montana and North Dakota has been transported by rail to the Québec refineries and the refinery in Saint John, New Brunswick. The North Atlantic refinery has also been receiving crude oil shipped from Texas via tanker. After the U.S., the top five sources for Canadian crude imports are Saudi Arabia, Iraq, Norway, Algeria and Angola.

Both regions are expected to increase receipts of western Canadian crude oil once Enbridge's Line 9 reversal is in service, which will deliver crude oil all the way to Montréal.

3.2 United States

Canada has been the top foreign supplier of crude oil to the U.S. since 2004 and is likely to remain as such for the foreseeable future. According to data from the EIA, Canada's exports to the U.S. increased by 306,000 b/d or 12 per cent in 2014 despite a 393,000 b/d or 5 per cent decline in total foreign imports. Canada exported 2.9 million b/d, with nearly all of these volumes being exported to the U.S.

Rising U.S. domestic production in recent years has been driven by drilling in the shale and tight oil plays in the Eagle Ford in Texas and Bakken in North Dakota. In 2014, U.S. production of crude oil exceeded the level of U.S. imports for the first time in 20 years. Annual production in the U.S. in 2014 grew by 1.2 million b/d from 2013, which is the highest growth recorded since 1990. This growth is expected to be more moderate in the next two years due to the impact of lower oil prices slowing production in more marginal drilling areas.

To date, increased light domestic production has displaced light crude oil imports, particularly at refineries on the U.S. Gulf Coast and the East Coast. The projected growth of 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. However, some imports of heavier crude types have also been displaced in the other U.S. regions.

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. crude oil market regions.

3.2.1 PADD I (East Coast)

The 1.3 million b/d refining capacity in the U.S. East Coast is comprised of nine refineries located in the states of Delaware, New Jersey, Pennsylvania and West Virginia. These refineries primarily process light crude oil (Figure 3.5). In 2014, these refineries processed 1.1 million b/d of crude oil, of which 651,000 b/d or 60 per cent was sourced from foreign sources.

The U.S. domestic portion of feedstock slate increased by 70 per cent from 254,000 b/d in 2013 to 436,000 b/d as a result of the growth of light U.S. Bakken production in North Dakota along with the development of rail facilities to the East Coast in 2013 and 2014 (Table 3.1).

Foreign imports to the region declined by 17 per cent, most of which was displaced by U.S. domestic production. However, imports of heavy crude oil from Canada increased as the new rail facilities provided the East Coast refineries new access to this supply source. PADD I refineries imported 282,900 b/d of crude oil from Canada. About 166,600 b/d was sourced from Western Canada in 2014 compared to 104,000 b/d in 2013. Of these imports, about 100,000 b/d arrived by rail.

Figure 3.5 2014 PADD I: Foreign Sourced Supply by Type and Domestic Crude Oil

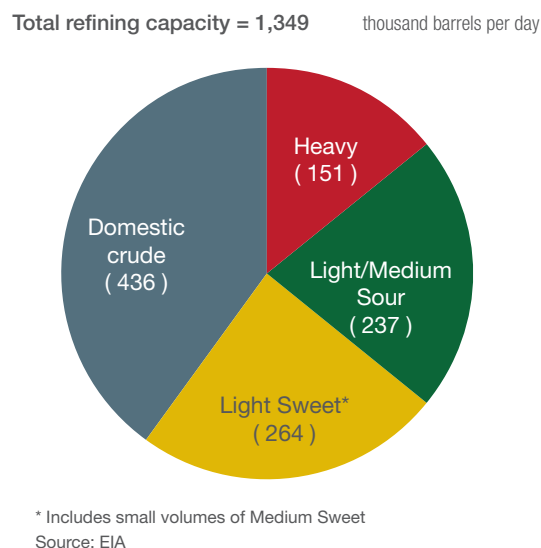


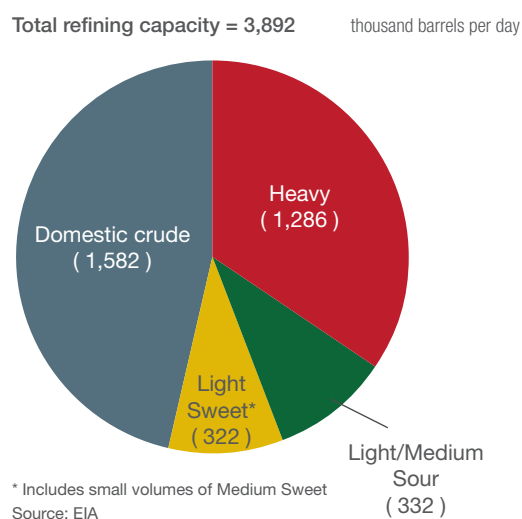
Table 3.1 Rail Offloading Terminals in PADD I

Operator	Location	Capacity (thousand b/d)	Scheduled In-Service	Description
PBF Energy (refinery)	Delaware City, DE	170 (130 light/40 heavy)	Operating since Feb 2013; expanded Aug 2014	Both light and heavy crude oil unloading capacity. Light oil double loop track for two 100-car unit trains
Axeon Specialty Partners (refinery)	Savannah, GA	9* *16 tank cars per day of heavy crude; expandable up to 32)	Operating since Jan 2014	Crude oil that is shipped by rail to Savannah could move to Paulsboro via backhauls on waterborne vessels
Westville	Eagle Point (near Paulsboro), NJ	44* *66 cars / day	Operating since Jan 2012	Can unload 66 cars / day using 22 offload spots or a unit train every 2 days.
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	60-80 104-car unit train/ day	Operating since Q3 2014	Light crude; possibly handle 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 a 5 year contract for 50,000 b/d
Eddystone Rail Company (Enbridge JV)	Philadelphia, PA	80* *one 118-car unit train; expandable to 2 unit trains (160,000+ b/d)	Operating since April 2014	A crude-by-rail-to-barge facility. First train received on May 3, 2014. Exclusive long- term contract with Bridger Logistics for existing capacity. Transport Bakken crude.
Philadelphia Energy Solutions (refinery)	Philadelphia, PA	280 four 104-car unit trains / day	Operating since Oct 2013; expanded Oct 2014	A crude-by-rail-to-barge facility. Terminal started operation on October 23, 2013 and was expanded from 2 unit trains to 4 on October 28, 2014
Plains All American Pipeline (PAAP)	Yorktown, VA	60	Operating since Dec 2013	First 98-car unit train received on Dec. 30, 2013. Up to 800 trains per year can be unloaded with up to 104 rail cars per train.
Total Existing Capacity		998,000 b/d		

3.2.2 PADD II (Midwest)

Over 3.9 million b/d of refining capacity is located in PADD II. In 2014, these refineries received 1.9 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 2014 PADD II: Foreign Sourced Supply by Type and Domestic Crude Oil



PADD II can be further divided into the Northern, Eastern, and Southern PADD II states. The primary market hubs within PADD II are located at Clearbrook, Minnesota for the Northern PADD II states; Wood River-Patoka, Illinois area for the Eastern PADD II states; and Cushing, Oklahoma for the Southern PADD II states.

The Midwest region is currently Canada's largest market due to its close proximity, large size and established pipeline network. However, this traditional market is becoming saturated as evidenced by the high level of inventories from growing domestic production and imports from Western Canada. Nonetheless, deliveries of western Canadian crude oil to this market are expected to increase by 190,000 b/d from 2014 levels by 2020.

Eastern PADD II

The total refining capacity in Eastern PADD II is over 2.5 million b/d from 14 refineries located throughout Michigan, Illinois, Indiana, Kentucky, Tennessee and Ohio. In 2014, this market collectively imported over 1.4 million b/d of crude oil supplies, of which 98 per cent were sourced from Western Canada. Imports of western Canadian heavy crude oil are estimated to increase slightly from current levels by 180,000 b/d in 2020 (Figure 3.7). In early 2015, Husky announced a postponement of its crude flexibility project by two years. The project was designed to allow the processing of up to 40,000 b/d of heavy crude oil from Western Canada and was originally scheduled to start in 2017 (Table 3.3).

Figure 3.7 PADD II (East): Crude Oil Receipts from Western Canada

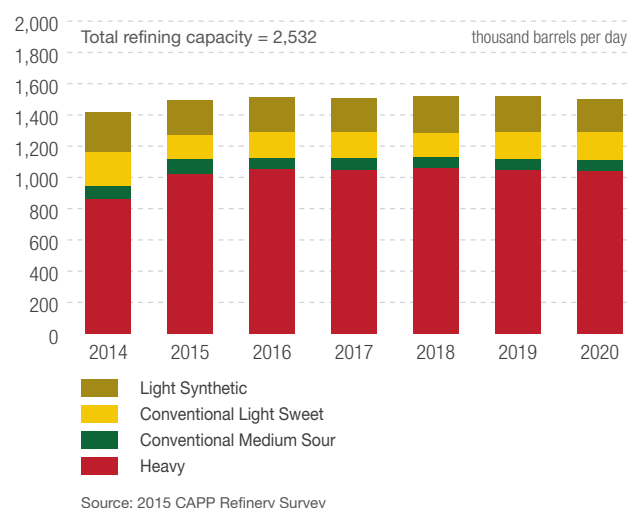


Table 3.2 Proposed Refinery Upgrade Projects in Eastern PADD II

Operator	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Estimated Cost (\$ million)	Description
Husky	Lima, OH	160	2019 (originally 2017)	300	Modifications to coker and other processing units to increase ability to process heavy crude oil by up to 40,000 b/d.

Northern and Southern PADD II

In Northern PADD II, there are two refineries located in Minnesota, a refinery in Wisconsin and two refineries in North Dakota. These five refineries have a combined capacity of 564,500 b/d. The Dakota Prairie refinery project was recently completed in April 2015. The refinery has a capacity of 20,000 b/d and is a joint venture between MDU Resources Group and Calumet Specialty Products. It will process Bakken crude oil to primarily make diesel fuel. Despite its small size, the refinery is significant as it is the first new U.S. refinery built since 1976. Additional similarly-sized refinery projects in North Dakota are currently being assessed.

There are seven refineries in Southern PADD II that account for a combined capacity of 816,000 b/d. These refineries are either located in Kansas or Oklahoma. U.S. domestic production satisfies 64 per cent of the combined refinery feedstock demand in these two regions. All of the foreign imports are sourced from Western Canada. Most, or 85 per cent, of the 457,000 b/d of imports was heavy crude oil.

Given the small relative size of these two markets and competition with U.S. domestic production for light crude oil demand, the growth in demand for western Canadian crude oil is limited. It is forecast to reach an additional 108,000 b/d from today's levels by 2020 (Figure 3.8).

The addition of a new coking facility at the National Cooperative Refinery Association (NCRA) McPherson refinery is scheduled to start up in late September 2015 (Table 3.2).

**Figure 3.8 PADD II (North & South):
Crude Oil Receipts from Western Canada**

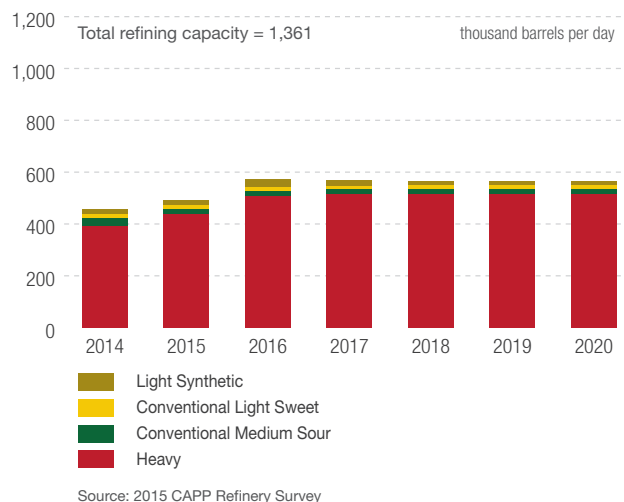


Table 3.3 Recent and Proposed Refinery Upgrades in Northern & Southern PADD II

Operator	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Estimated Cost (\$ million)	Description
Dakota Prairie LLC	Dickinson, ND	20	Completed April 2015	400	New refinery processing Bakken crude oil to produce primarily diesel.
NCRA	McPherson, KS	85	Q4 2015	555	Plan to expand capacity to 100,000 b/d and increase heavy crude oil processing capacity to 50% with installation of new delayed coker.

3.2.3 PADD III (Gulf Coast)

There are 50 refineries located on the Gulf Coast with a combined refining capacity of 9.5 million b/d or more than half of the total refining capacity in the U.S. The vast majority of this capacity is located in two states: Louisiana and Texas. The remaining refineries are located in Alabama, Arkansas, Mississippi, and New Mexico.

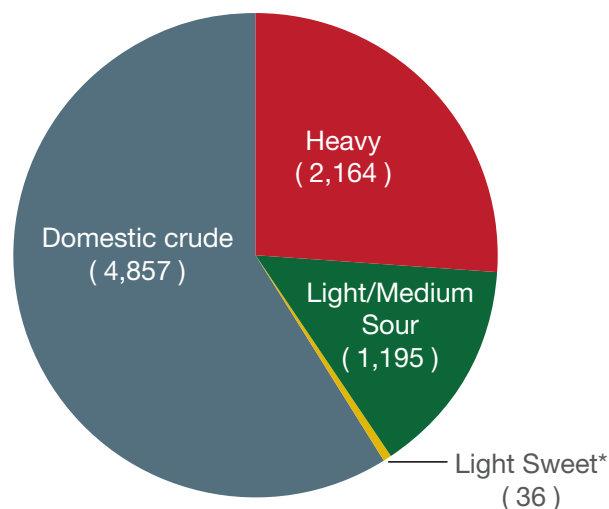
Greater access to this market would allow production from Canada to significantly expand its reach into the United States. Most of the Gulf Coast refineries have the capacity to process heavy, high sulphur crude oil, which is similar to the growing supplies expected to be produced from Western Canada.

Foreign imports of crude oil totaled 3.2 million b/d in 2014, which was a decline of 13 per cent from 2013. Growing production from U.S. shale and tight oil plays such as the Eagle Ford and Permian Basin in Texas, has almost completely displaced light-sweet crude oil imports from refineries along the U.S. Gulf Coast (Figure 3.9).

The supplemental use of rail has almost doubled the volumes of western Canadian crude oil destined for the U.S. Gulf Coast region from only 118,000 b/d in 2013 to 235,000 b/d in 2014. However, limited pipeline connection between western Canadian production and the Gulf Coast is still a major barrier to increased access to this market. CAPP's 2015 refinery survey indicates that western Canadian crude oil supplied to this market could reach 468,000 b/d in 2020. Note that these volumes are likely understated as only seven refineries in this region provided responses to the survey. Some refinery upgrades have been announced that could increase the size of this market or its ability to process heavy crude oil in the near future (Table 3.4).

Figure 3.9 2014 PADD III: Foreign Sourced Supply by Type and Domestic Crude Oil

Total refining capacity = 9,498 thousand barrels per day



* Includes small volumes of Medium Sweet
Source: EIA

Saudi Arabia, Mexico, and Venezuela are the top three suppliers of foreign sourced crude oil to PADD III. With roughly an equal share, these countries combined account for 65 per cent of total imports. Crude oil imports from Saudi Arabia consist mostly of light and medium sour crude oils. Venezuela and Mexico supply the majority of all heavy imports. The opportunity for growing supplies from Western Canada to gain a presence in this market lies in the displacement of heavy imports and not competition with U.S. domestic production, which is primarily light crude oil.

Table 3.4 Recent and Proposed Refinery Upgrades in PADD III

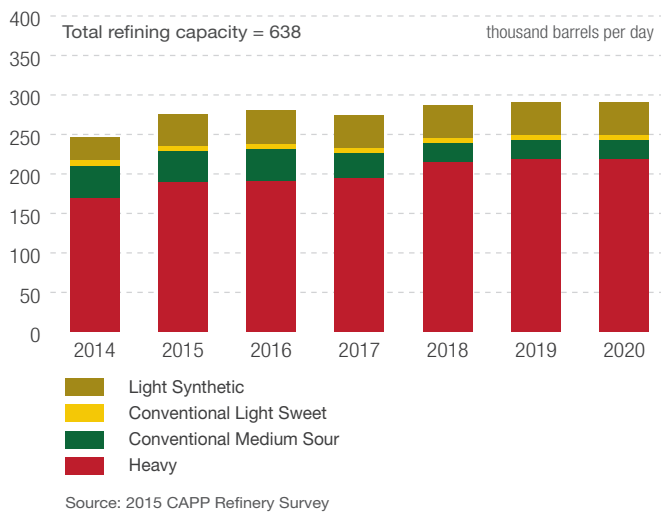
Operator	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Description
Delek	Tyler, TX	75	Completed Mar 2015	Expansion from 60,000 b/d capacity
Marathon	Garyville, LA	522	2018 (decision in early 2015)	Installation of hydrotreating, hydrocracking, & desulphurization equipment.
Valero	McKee, 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.

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 638,000 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.

In 2014, PADD IV refineries processed 247,000 b/d of Canadian crude oil, representing, 43 per cent of total feedstock requirements in the region. Receipts of heavy western Canadian supply are forecast to increase slightly from current levels (Figure 3.10). One refinery expansion has been announced that will occur within the forecast period (Table 3.5).

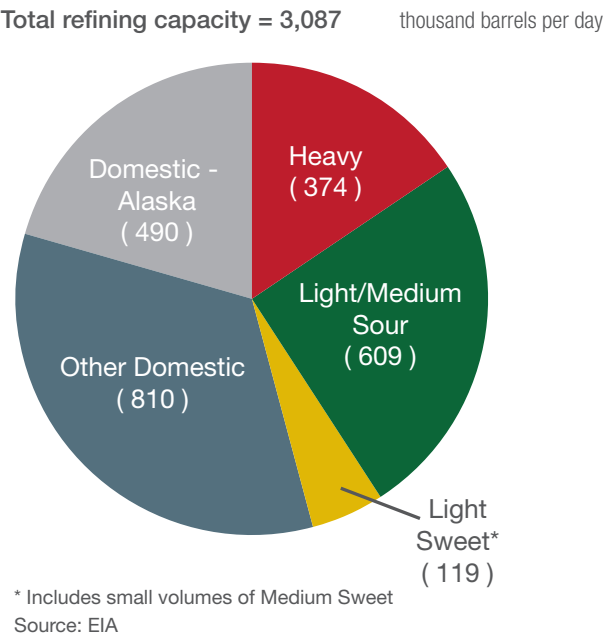
Figure 3.10 PADD IV:
Crude Oil Receipts from Western Canada



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 take production from California and Alaska and also have good access to tankers that can import crude from more distant regions. There is over 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 2014 PADD V: Foreign Sourced Supply by Type and Domestic Crude Oil



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.

Table 3.5 Proposed Refinery Upgrade Projects in PADD IV

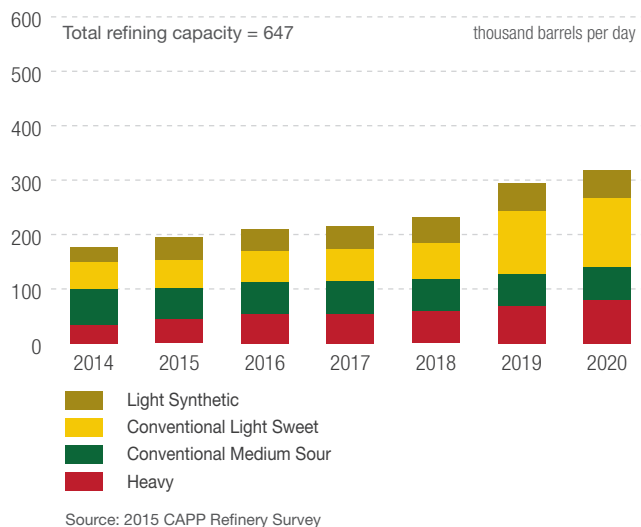
Operator	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Estimated Cost (\$ million)	Description
Calumet Montana Refining	Great Falls Montana	10 (20 after expansion)	Q1 2016	400	Installation of new crude unit, mild pressure hydrocracker and tankage

Washington

Refining capacity in Washington totals 647,000 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 497,000 b/d in 2014, Alaskan production is only about a quarter of the peak levels achieved in 1988. Washington refineries have become increasingly dependent on foreign imports but some have also recently been able to access part of the North Dakota's growing crude oil production supply through the use of rail.

In 2014, Washington refineries received 223,000 b/d of foreign imports of which 77 per cent was supplied by Canada. Results from CAPP's refinery survey indicate that demand for crude oil from Western Canada will increase by 141,000 b/d from current levels, which translates to an 80 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



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 are either 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. 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 area of 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.

Direct pipeline access to this market is unlikely due to the limited size of the market but 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 3.6).

In 2014, California refineries imported 805,000 b/d of crude oil from foreign sources, which is equivalent to almost half of the total feedstock demand (Figure 3.13).

Figure 3.13 2014 PADD V (California): Foreign Sourced Supply by Type and Domestic Crude Oil

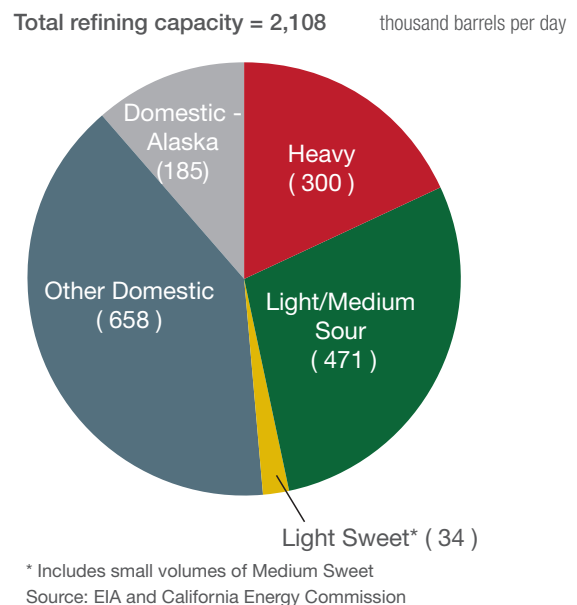


Table 3.6 Rail Offloading Terminals in Western Canada and PADD V

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	Operating since Dec 2013	
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 2016	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		

3.3 International

There is growing interest in Canada's crude oil supply in both Europe and Asia. In 2014, Statistics Canada reported shipments of Canadian crude oil destined to Italy, United Kingdom, Chile, Norway, Bahamas, France, Ireland, Spain and India.

The European Union Parliament's original fuel quality directive (FQD) proposal discriminated against Canadian oil sands crude as the only more carbon intensive crude oil. The Canadian government and industry objected, noting that Canadian crude was less carbon intensive than some other sources of crude and that other jurisdictions were less transparent in their reporting. Late in 2014, the FQD was revised to avoid discrimination against Canadian oil sands crude. Exports of Canadian crude oil to Europe have begun to occur and expanded transportation infrastructure in Canada with proposed pipelines to the coast will lead to increased exports in the future.

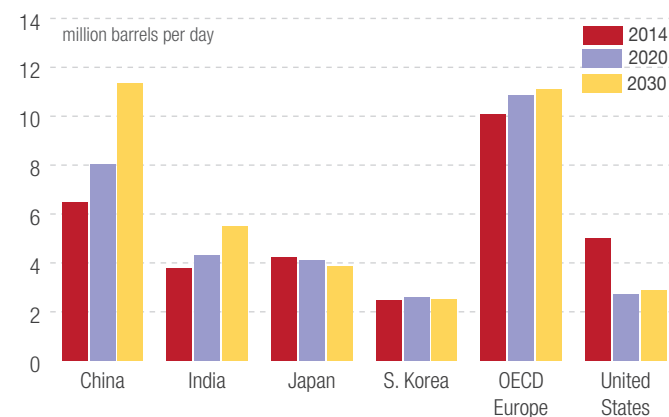
Demand for petroleum liquids in China and India combined are expected to account for close to half the projected world demand increase in 2030 compared 2014 levels. The International Energy Agency in its World Energy Outlook 2014, which was released in November 2014, predicts that China will become the largest consumer of oil in the world, overtaking the United States in the early 2030s. Table 3.7 shows forecasted oil demand in major Asian markets. Figure 3.14 shows the changing global import needs. Not surprisingly, imports of petroleum from China and India are expected to grow. Slight growth is expected in OECD Europe but demand is expected to drop in the U.S., which is currently the market for almost all of Western Canada's crude oil exports.

Table 3.7 Total Oil Demand in Major Asian Countries

<i>million b/d</i>	2013	2020	2025	2030
China	9.8	12.0	13.9	15.1
India	3.7	4.9	5.8	7.0
Japan	4.4	3.7	3.3	3.0

Source: IEA World Energy Outlook 2014, New Policies Scenario

Figure 3.14 Global Net Oil Imports: 2014 to 2030



Source: EIA Annual Energy Outlook 2015

3.4 Markets Summary

Market diversity and corresponding expanded transportation capacity remain key features of this latest outlook. Canadian production requires tidewater access in order to reach global markets and even some prospective North American markets, including California. Eastern Canada and the U.S. Gulf Coast represent the greatest opportunity for expanded markets in North America for Canadian crude oil production.

PADD I holds limited expansion opportunities due to its size, and primarily light crude oil requirements that will likely be increasingly satisfied through growing U.S. domestic production. The larger PADD II market is essentially saturated with western Canadian and domestic U.S. supplies. Growing supplies of western Canadian production must be transported to tidewater if it is to ultimately reach international markets. Recent test cargoes of Canadian crude oil destined for Italy, United Kingdom, Chile, Norway, Bahamas, France, Ireland, Spain and India show there is growing interest from European and Asian markets for Canadian production.

4 | TRANSPORTATION

The growing supply of western Canadian crude oil relies on the availability of a strong transportation infrastructure network to connect to refining markets. This transportation network involves all modes of transportation that includes pipelines, rail, marine and trucks. However, the existing pipeline infrastructure and proposed pipeline projects provide the most efficient means of transporting large quantities of crude oil. Figure 4.1 shows both the existing and proposed pipeline projects that could deliver large volumes of western Canadian crude oil to the East Coast, West Coast, U.S. Gulf Coast and offshore markets.

Figure 4.1 Existing and Proposed Canadian & U.S. Crude Oil Pipelines



4.1 Existing Crude Oil Pipelines Exiting Western Canada

There are four major pipelines which move western Canadian crude out of the WCSB. Of these pipelines, 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 3.8 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). Pipeline capacity continues to be tight with strong growth in production volumes forecast until 2020. In addition, operational constraints can and have, at times, reduced the 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	2,621	Operating since 1950
Enbridge Alberta Clipper Expansion	+230	Q3 2015
Enbridge Line 3 Restored	+370	2H 2017
Kinder Morgan Trans Mountain	300	Operating since 1953
Trans Mountain Expansion	+590	Q4 2018
Spectra Express <small>*downstream Platte operating since 1952</small>	280	Operating since 1997*
TransCanada Keystone	591	Operating since 2010
TransCanada Keystone XL <small>**assuming approval obtained by end 2015</small>	+830	2018**
Enbridge Northern Gateway	+525	2019
TransCanada Energy East	+1,100	2020
Total Existing Capacity		3,792
Total Proposed Additional Capacity		+3,645

The next sections describe the existing pipeline projects. The proposed projects are discussed in the subsequent sections and are categorized by their 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 several 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 2.6 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 space 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 2017.

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 Expansion Projects

The current capacity on the Enbridge Mainline System between Edmonton, Alberta and Superior, Wisconsin is approximately 2.6 million b/d and is comprised of the capacity from a number of pipelines. These pipelines include Line 1, Line 2, Line 3, Line 4, Line 65 and the Alberta Clipper, which is also identified as Line 67.

Enbridge recently completed a number of expansions and is also planning further expansions that will allow western Canadian crude to reach existing markets in the Midwest and Ontario and new markets in the U.S. Gulf Coast. Enbridge is undertaking a \$7 billion project to replace its Line 3 pipeline. The new pipeline is scheduled to be in service in the second half of 2017 and will restore Line 3 to its original capacity of 760,000 b/d.

The Alberta Clipper is a 36-inch diameter pipeline which extends from Hardisty, Alberta to Superior, Wisconsin. Enbridge completed the Phase 1 Expansion of this pipeline in the fall of 2014, which increased its original capacity by 120,000 b/d from 450,000 b/d to its current capacity of 570,000 b/d. The Phase 2 Expansion, scheduled to be in service in Q3 2015 would provide an additional 230,000 b/d and bring the Alberta Clipper pipeline up to its ultimate designed capacity of 800,000 b/d. The Alberta Clipper pipeline will be expanded through the addition of new pumps and station upgrades.

Enbridge's Light Oil Market Access Program (LOMAP) is directed at expanding market access for light crude oil production from North Dakota and Western Canada. The Southern Access Pipeline is part of the Lakehead System (Enbridge U.S. Mainline) and runs from Superior, Wisconsin to Flanagan, Illinois. The current capacity is 560,000 b/d. As part of its LOMAP, Enbridge completed an initial expansion of the pipeline by 160,000 b/d from its original capacity of 400,000 b/d in August 2014. The next step in the plan will be to further increase capacity on the pipeline by 240,000 b/d in Q2 2015 through the addition of pumping stations. Enbridge has delayed the last expansion phase of an additional 400,000 b/d until 2017, which would bring the Southern Access pipeline to its ultimate designed capacity of 1.2 million b/d.

4.1.2 Kinder Morgan Trans Mountain

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

The current capacity on the pipeline system is 300,000 b/d (assuming 20 per cent of the volumes being transported are heavy crude oil). Of the total capacity, 221,000 b/d is allocated to refineries with connections in British Columbia and Washington State and 79,000 b/d is allocated to the Westridge terminal for marine exports. Of the capacity designated to the marine terminal, 54,000 b/d or 68 per cent is underpinned by firm contracts and the remainder is available for spot shipments. Demand for access to this pipeline has been high and as such the nominations for service on this pipeline have been in apportionment since late 2010. See Section 4.5.2 for details on the Trans Mountain Expansion Project.

4.1.3 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 designed capacity on Express is 280,000 b/d. The ability to move crude on the Express pipeline is limited due to insufficient downstream capacity on the Platte pipeline but rail connections have helped to increase throughput capacity. About 225,000 b/d of the capacity on Express is contracted. Spectra held an open season from December 10, 2014 to January 30, 2015 that offered 19,000 b/d of capacity for committed service that could be available through debottleneck work that would optimize use of Express's design capacity. These contracts would be effective by late 2016.

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.

4.1.4 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 companies which own the pipelines that 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, and the proposed TransCanada Energy East Pipeline into Eastern Canada and Keystone XL.

4.2.1 Enbridge - Alberta Regional Pipeline

Enbridge - Edmonton to Hardisty

Enbridge's new 36-inch diameter pipeline from Edmonton to Hardisty was placed into service in May 2015. The pipeline has an initial capacity of 570,000 b/d and will reach its full designed capacity of 800,000 b/d in Q3 2015 once all tanks are in place.

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. Pending regulatory approvals, the target in-service date for the Heartland pipeline is late 2016.

Grand Rapids Pipeline Project

TransCanada in partnership with Brion Energy Corporation (formerly Phoenix Energy Holdings Limited) 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 is a 460 km long dual pipeline system between the producing area northwest of Fort McMurray and Heartland. It includes a pipeline that could transport up to 900,000 b/d of crude oil and another pipeline that could transport up to 330,000 b/d of diluent. The pipeline in crude oil service is targeted to be in service by mid-2016. TransCanada will operate the pipeline and Phoenix has entered into a long-term commitment to ship crude oil and diluent on the pipeline system. Following a hearing in June and July 2014, regulatory approval from the Alberta Energy Regulator for the pipeline was received in October 2014 with certain conditions.

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 4.1.3.

4.3.2 TransCanada Keystone

See Section 4.1.4.

4.3.3 Southern Access Extension

Construction of an extension to Enbridge's Southern Access pipeline is underway. The proposed extension would be a 24-inch diameter pipeline that would run from Flanagan, Illinois to Patoka, Illinois. The pipeline would have an initial capacity of 300,000 b/d and is targeted to be in-service in Q4 2015.

4.3.4 Enbridge Line 6B

As part of its Eastern Access program, Enbridge has fully completed replacement of Line 6B. The new segment from Griffith, Indiana to Stockbridge, Michigan was put in service in Q2 2014. The segment from Stockbridge to the Canadian border was put in service in October 2014. As a result, capacity on Line 6B increased from 240,000 b/d to its current capacity of 500,000 b/d.

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 system originates at Flanagan, Illinois and receives crude oil from the Enbridge Mainline. From there, crude oil can be transported to Griffith, Indiana via Spearhead North or to Cushing, Oklahoma on Spearhead South.

As part of its Light Oil Market Access project, Enbridge is twinning the Spearhead North (Line 62) pipeline by constructing a new pipeline that would be located parallel to the existing pipeline. This new pipeline would provide an incremental capacity of 570,000 b/d and is targeted to be in service at the end of Q3 2015.

4.3.7 Enbridge Flanagan South

Enbridge's newly operating 36-inch diameter Flanagan South Pipeline has a capacity of 585,000 b/d and an ultimate design capacity of 880,000 b/d after pump station enhancements. It originates in Pontiac, Illinois, and terminates in Cushing, Oklahoma. It traverses Illinois, Missouri, Kansas, and Oklahoma. The majority of the pipeline runs parallel to Enbridge's Spearhead South pipeline's right-of-way. Enbridge shippers that contract for capacity on Flanagan South are able to nominate crude volumes originating in Western Canada for delivery to U.S. Gulf Coast markets. In order to provide this service, Enbridge utilizes its mainline facilities and capacity has been reserved on the downstream Seaway pipeline that delivers crude from Cushing to the US Gulf Coast.

4.3.8 Enbridge Toledo Pipeline Expansion

Enbridge operates a pipeline which 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. The Line 17 is a 16-inch diameter pipeline that pre-existed Line 79 and extends from Stockbridge, Michigan to Toledo, Ohio and has a capacity of 100,000 b/d. These two pipelines combined, provide a total capacity of 180,000 b/d to serve 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	1,525
Southern Access	Superior, WI	Flanagan, IL	Operating	560
Southern Access Expansion			Proposed - Q2 2015	+240
Southern Access Expansion			Proposed - 2017	+400
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	Operating since Dec 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
PAAP Diamond	Cushing, OK	Memphis, TX	Proposed - Q4 2016	+200

4.3.9 Plains All American Diamond Pipeline

Plains All American announced plans to build a new 200,000 b/d crude oil pipeline from Cushing, Oklahoma to Valero's refinery in Memphis, Tennessee by early 2017. The pipeline is estimated to cost \$900 million. Valero also holds the option until January 2016 to purchase 50 per cent interest of the pipeline.

4.4 Oil Pipelines to the U.S. Gulf Coast

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

Western Canadian and Bakken production historically had limited access to this market but two pipeline projects began operating in 2014 that connected supply from the Midwest to the U.S. Gulf Coast (Table 4.3).

4.4.1 Enbridge/Enterprise Seaway

The Seaway Pipeline system is jointly owned by Enbridge Inc. and Enterprise Products Partners L.P. Seaway is comprised of two parallel 30-inch diameter pipelines. The total current capacity is 850,000 b/d with 400,000 b/d contributed by the legacy pipeline between Cushing, Oklahoma and the Freeport, Texas area and 450,000 b/d contributed by the Seaway Twin pipeline from the ECHO terminal to Beaumont, Port Arthur, which was recently brought into service on December 1, 2014.

The system can deliver to Jones Creek, Freeport, ECHO terminal, Texas City & Port Arthur. The Jones Creek to ECHO terminal lateral is a 36-inch diameter pipeline with a capacity of 850,000 b/d while the ECHO terminal to Beaumont/Port Arthur lateral is a 30-inch diameter pipeline with a capacity of 650,000 b/d. As mentioned previously in Section 4.3.7, a portion of the Seaway pipeline has been reserved to take deliveries from the Flanagan South pipeline for those shippers that have nominated deliveries to Gulf Coast.

U.S. Gulf Coast market access for western Canadian crude oil has only started to emerge in recent years. The direction of flow on the legacy Seaway pipeline was reversed on May 17, 2012 in order to allow crude oil to be transported from the bottlenecked Cushing, Oklahoma hub to the Gulf Coast refineries near Houston. The first volumes arrived at the Jones Creek terminal, just north of Freeport, on June 6, 2012. The original capacity of the reversed pipeline was only 150,000 b/d but since January 2013, its capacity was increased to 400,000 b/d through pump station modifications and additions. On average, 290,000 b/d was transported in 2014 on the Seaway system.

4.4.2 TransCanada Keystone XL

The Keystone XL Pipeline is a 36-inch-diameter crude oil pipeline proposed by TransCanada that originates in Hardisty, Alberta, and extends south to Steele City, Nebraska. The project was originally proposed in 2005. TransCanada applied for a Presidential Permit with the U.S. Department of State to build this cross-border pipeline in September 2008; the long awaited decision on the project is assumed to occur before the end of 2015.

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

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

4.4.3 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 proposed Keystone XL would provide 1.4 million b/d of capacity of which 1.1 million b/d is underpinned by long term contracts.

4.4.4 Capline Reversal

The Capline pipeline currently transports crude oil northbound from St. James, Louisiana to Patoka, Illinois. It is a 40-inch diameter pipeline system with a capacity of 1.2 million b/d of capacity. If reversed, the pipeline could move western Canadian crude to refineries in Louisiana but infrastructure upstream of the origination point would be required to connect to sources of supply. Marathon operates the pipeline while Plains All American Pipeline is the majority owner; the other part owner is BP. The owners have indicated that they would consider connecting Capline to the Diamond pipeline (See Section 4.3.9).

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 4.3 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			Operating since Dec 2014	450
TransCanada Keystone XL	Hardisty, AB	Steele City, NE	Proposed - 2018	+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
Capline Reversal	Patoka, IL	St, James, LA	Proposed – TBD	+1,200

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. In June 2014, the project was approved by the Governor in Council subject to 209 conditions and further discussions with Aboriginal communities. The target in-service date for the project is 2019.

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 4.1.2). The capital cost for the Trans Mountain Pipeline Expansion project 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 depending on demand. 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 revamped configuration would, in effect, add 590,000 b/d of capacity 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 construction starts in 2016, the expanded pipeline would be operational in late 2018.

4.6 Oil Pipelines to Eastern Canada

In 2014, refineries in Eastern Canada processed almost 1.2 million b/d of crude oil, of which 542,000 b/d originated 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.

4.6.1 Enbridge Line 9 Reversal

The Enbridge Line 9 Reversal project is a 30-inch diameter pipeline that will transport crude oil from Sarnia, Ontario to Montréal, Québec. The 9A portion has been flowing crude oil from the Sarnia, Ontario to North Westover, Ontario since August 2013. The current capacity is 152,000 b/d.

Reversal of the remaining portion, Line 9B, to flow crude oil from North Westover, Ontario to Montréal, Québec and expansion of the completed pipeline to 300,000 b/d is targeted for in service in Q2 2015. Line 9B awaiting the final leave to open from the NEB which was filed in February 2015.

4.6.2 TransCanada Energy East

TransCanada Energy East is a proposed pipeline system that would provide transportation service from Hardisty, Alberta and Moosomin, Saskatchewan to delivery points in Québec and New Brunswick. The major components of the project includes the conversion of a natural gas pipeline to oil service and constructing new pipeline segments in Alberta, Saskatchewan, Manitoba, Eastern Ontario, Québec and New Brunswick. Construction of associated facilities, pump stations and tank terminals, including marine facilities would also be required. The 4,600 km long pipeline is estimated to cost \$12 billion and would have a capacity of 1.1 million b/d, of which 900,000 b/d is underpinned by firm contracts.

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 2018	+590
Enbridge Northern Gateway	Bruderheim, AB	Kitimat, BC	Proposed - 2019	+525

Table 4.5 Summary of Crude Oil Pipelines to Eastern Canada

Pipeline	Originating Point	Destination	Status	Capacity (thousand b/d)
Enbridge Line 9 Reversal	Sarnia, ON	Montréal, QC	Proposed	+300
9A	Sarnia, ON	North Westover, ON	Operating since Aug 2013	152
9B	North Westover, ON	Montréal, QC	Q2 2015	
TransCanada Energy East	Hardisty, AB	Québec City, QC / St. John, NB	Proposed - 2020	+1,100

In TransCanada's original application to the NEB filed on October 30, 2014, the project included delivery points to three refineries in Eastern Canada and two marine terminals, one at Gros Cacouna, Québec and one at Saint John, New Brunswick to allow for exports to international markets.

Waters surrounding Gros Cacouna are included within the designated critical habitat for the St. Lawrence Estuary population of beluga whales. In November 2014, the Committee on the Status of Endangered Wildlife in Canada (COSEWIC) recommended the re-designation of this whale population from a threatened to an endangered species. In April 2015, TransCanada announced that it will not be building the marine terminal and oil storage facility at Gros Cacouna, Québec and will be relocating the marine terminal to a different site that would not affect the beluga whale population. TransCanada intends to file an amendment to its regulatory filing in Q4 2015. The revised targeted in-service date for the project is 2020.

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. Of this initial capacity, 162,000 b/d is secured by long-term contracts. Enbridge is evaluating a future expansion of the Southern Lights system to increase capacity to 275,000 b/d by 2025 through the use of additional horse power and drag reducing agents.

4.7.2 Enbridge Northern Gateway Diluent

As part of its Northern Gateway Project, Enbridge is proposing a diluent pipeline that would run from Kitimat, British Columbia to Bruderheim, Alberta. The proposed capacity of the pipeline is 193,000 b/d. The project has been approved with numerous conditions. The updated target in-service date for the project is 2019.

4.7.3 TransCanada Grand Rapids Diluent

As part of its Grand Rapids Pipeline project, which was approved in October 2014, TransCanada plans to build a diluent line from the Heartland region to Fort McMurray, Alberta. The diluent pipeline would have a capacity of 330,000 b/d and is expected to be operating in 2017. Anchor shipper commitments have been obtained.

4.7.4 Kinder Morgan Cochin Reversal Project

Kinder Morgan's Cochin system is a 12-inch diameter multi-product pipeline. In April 2014, the pipeline was removed from ethane-propane service. Since July 2014, the pipeline has been shipping condensate from Kankakee County, Illinois to Fort Saskatchewan, Alberta. The pipeline's estimated capacity is 95,000 b/d.

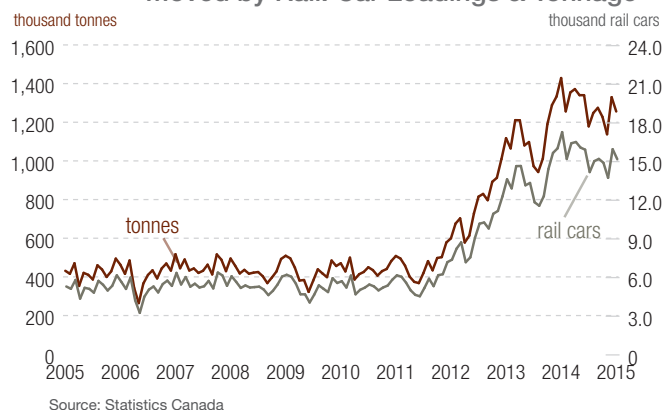
Table 4.6 Summary of Diluent Pipelines

Pipeline	Originating Point	Destination	Status	Capacity (thousand b/d)
Enbridge Southern Lights Southern Lights Expansion	Flanagan, IL	Edmonton, AB	Operating Proposed - 2025	180 +95
Enbridge Northern Gateway	Kitimat, BC	Bruderheim, AB	Proposed - 2019	+193
Kinder Morgan Cochin Conversion	Kankakee County, IL	Fort Saskatchewan, AB	Operating since July 2014	95
TransCanada Grand Rapids	Heartland, AB	Fort McMurray, AB	Proposed - 2017	+330

4.8 Crude Oil by Rail

In recent years, rail transport of crude oil has grown as an alternative mode of transport to accommodate the rapid growth from new supply regions that quickly exceeded the available pipeline capacity. Rail transport is expected to continue to rise due to the protracted regulatory processes for new pipelines. The number of Canadian rail car loadings of crude oil and petroleum products in 2014 increased by 14 per cent over 2013. Monthly loadings ranged between 13,745 car loads and 17,288 car loads throughout the year (Figure 4.2).

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



Pipelines are the most efficient means of connecting large supply basins to large market areas. However, in the absence of adequate pipeline capacity exiting Western Canada, rail transport will continue to rise due to the protracted regulatory processes for new pipelines and growing production and the startup of new terminals. There is a long-term future for this mode of transportation serving small producers without pipeline connections but also providing all producers with the flexibility to move to different markets in response to demand opportunities.

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 existing rail tracks in place to reach the 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. However, producers have continued to transport DilBit because raw bitumen can become too viscous as a result of cold temperatures en route. This can 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.
- **Product integrity:** Commodity isolation in separate rail tank cars results in no loss of quality 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. A unit train loading terminal can be constructed in about 12 months.

In 2014, industry data indicated that about 185,000 b/d of western Canadian crude oil was transported to market by rail. In 2015, rail movements is expected to grow slightly to 200,000 b/d. In 2016, CAPP estimates the annual crude movement by rail could rise to 250,000 b/d. In 2017, it could reach 350,000 b/d. In 2018, rail volumes are estimated at around 500,000 b/d to 600,000 b/d if Keystone XL is not available but if the pipeline is in place, volumes might decrease significantly. Beyond 2018, as new pipeline projects become available, the crude volumes transported by rail could be reduced.

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

The current rail loading capacity originating in Western Canada is 776,000 b/d. Some new facilities and expansion projects that were originally proposed to be in service by the end of 2015 have been deferred with unknown new timing. Figure 4.4 shows all the major existing and proposed rail terminals for uploading crude oil in Western Canada.

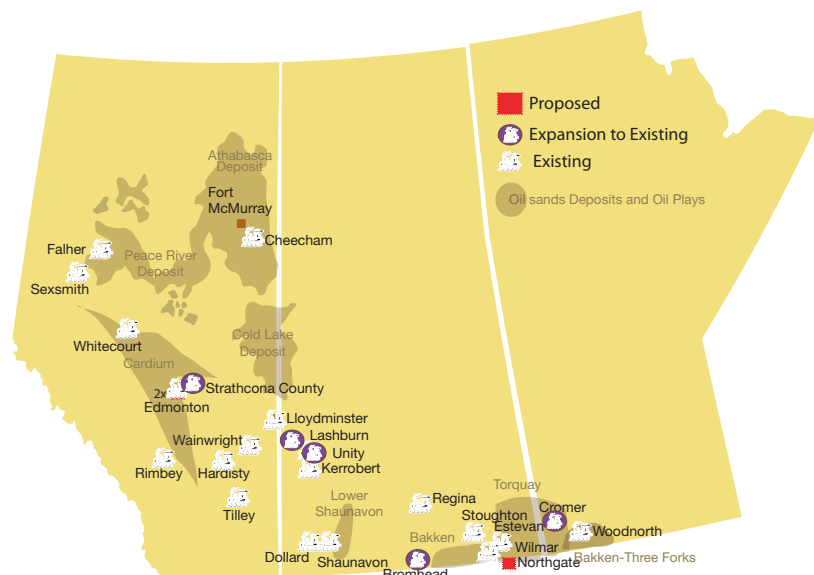
Transport Canada and the U.S. Department of Transportation announced new harmonized tank car standards in May 2015 in response to increased crude oil moved by rail and to address growing concerns around safety.

Figure 4.3 North American Rail Network



Source: Rail Association of Canada

Figure 4.4 Rail Loading Terminals in Western Canada



Major* Announced Rail Uploading Terminals in Western Canada			
Operator	Location	Expanded / Proposed Capacity** ('000 b/d)	Scheduled Startup
ALBERTA			
Keyera/Enbridge	Cheecham	32	Operating since Oct 2013
Grizzly	Conklin	10	Operating since Mar 2014; expansion potential
Canexus	Bruderheim (near Edmonton)	100	Operating; Expandable
Gibson	Edmonton	20 (expandable to 40)	Q3 2015
Keyera/Kinder Morgan	Edmonton	30 to 40	Operating since September 2014
Pembina	Edmonton	40	Operating
Gibson/USDG	Hardisty	120 (expandable to 240)	Operating since July 2014; expansion 18 months from decision
Altex	Lynton (Ft. McMurray)	15	Operating
Kinder Morgan/Imperial	Strathcona County	210 to 250	Operating since April 2015
SASKATCHEWAN			
TORQ Transloading	Bromhead	20 +58	Operating; Expansion planned
Crescent Point	Dollard	27	Operating; Expansion Q2 2014
Altex	Lashburn	35 +25	Operating; Expansion underway
TORQ Transloading	Lloydminster	25	Operating; Expandable to 88
Ceres Global	Northgate	35	Construction on hold; Expandable to (70,000)
Crescent Point	Stoughton	45	Operating
Altex	Unity	15	Operating
TORQ Transloading	Unity	22 +44	Operating; Expansion underway
MANITOBA			
Tundra	Cromer	30 +30	Operating; + ultimate expansion
TOTAL		776,000 b/d + potential expansions	

*Facilities with less than 15,000 b/d are not shown

**Capacities of facilities are not exactly comparable due to differences within factors used to determine capacity such as operating hours, available car spots and contracts in place.

4.9 Transportation Summary

An expansion of the existing transportation infrastructure is needed to connect growing crude oil supply from Western Canada to new markets. Pipelines are the preferred mode of transportation to move crude oil but the protracted regulatory processes continues to present a number of challenges. At least one new pipeline project is needed in the very near term to accommodate growing supplies.

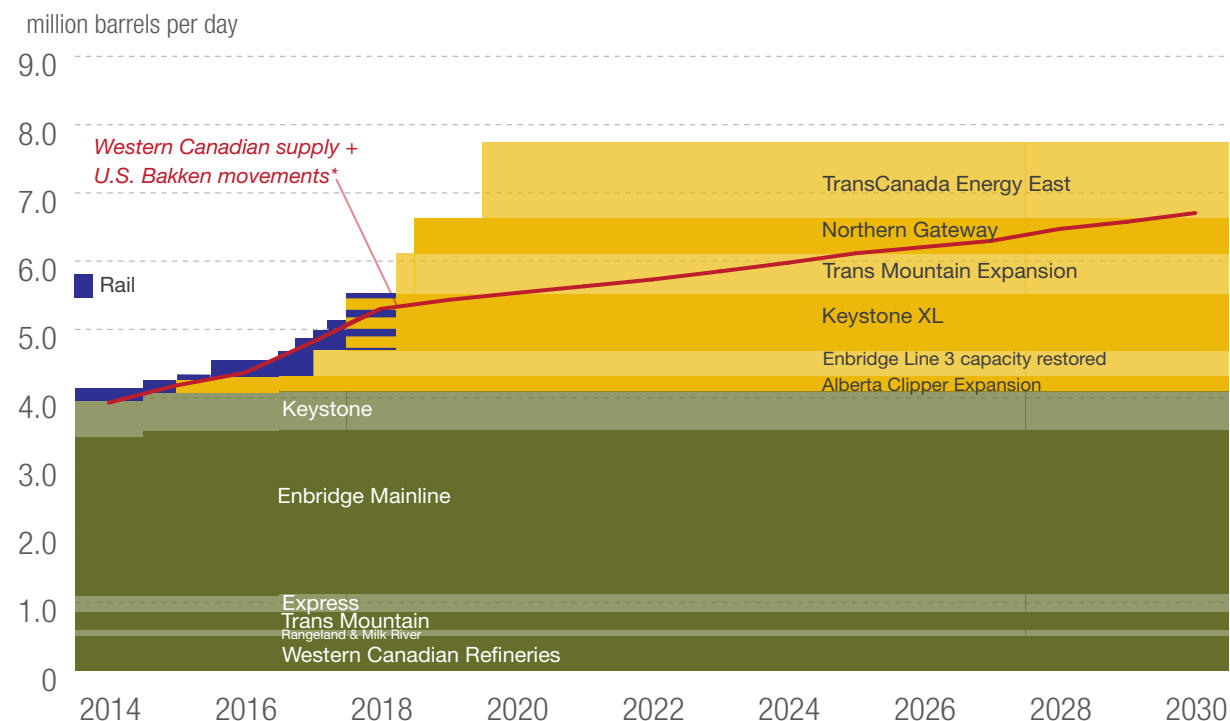
Figure 4.5 shows the existing and proposed takeaway capacity exiting the WCSB versus forecasted crude oil supply movements. The purple represents the growing rail throughput that could occur until 2018. The forecasted supply movements was developed by coupling CAPP's latest supply forecast of western Canadian production with U.S. Bakken volumes that would utilize a portion of the pipeline capacity that exits Western Canada.

The proposed pipeline projects are stacked in order of the reported timing of the various individual projects. It should not be interpreted as CAPP's view of the likelihood of one project proceeding faster than another.

The Keystone XL project would offer connections to the U.S. Gulf Coast refineries. The Trans Mountain Expansion and Northern Gateway projects would provide access to the West Coast and allow deliveries to Asian and Californian markets while TransCanada Energy East would provide access to the East Coast and allow deliveries to be made to European markets. These projects target three different markets and as such all will be needed to provide western Canadian producers with a level of market diversification that would allow the industry to flourish and grow. Increasing market optionality is of vital importance to companies considering investing large amounts of capital in order to realize the enormous resource potential that Western Canada holds. It should be noted that the startup timing for all of the pipeline proposals have been delayed from the dates reported last year, which reflects the difficulties industry is facing in putting into place large linear infrastructure projects.

In 2014, crude by rail volumes averaged 185,000 b/d. Crude by rail continues to be used as a complement to pipelines with volumes moving by rail growing to 2018. Beyond that rail use will be primarily impacted by the timing of proposed pipeline projects.

Figure 4.5 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.

GLOSSARY

Asphalt plant	A facility that processes crude oil into various types and grades of asphalt, ranging from dust-abatement road oils to highway-grade asphalt, to roofing tar.
API Gravity	A specific gravity scale developed by the American Petroleum Institute (API) for measuring the relative density or viscosity of various petroleum liquids.
Barrel	A standard oil barrel is approximately equal to 35 Imperial gallons (42 U.S. gallons) or approximately 159 litres.
Bitumen	A heavy, viscous oil that must be processed extensively to convert it into a crude oil before it can be used by refineries to produce gasoline and other petroleum products.
Coker	The processing unit in which bitumen is cracked into lighter fractions and withdrawn to start the conversion of bitumen into upgraded crude oil.
Condensate	A mixture of mainly pentanes and heavier hydrocarbons. It may be gaseous in its reservoir state but is liquid at the conditions under which its volumes is measured or estimated. US condensate is arbitrarily divided into two broad categories. The first is lease condensate produced at or near the wellhead (either natural gas or crude oil). The second category is plant condensate, also known as NGL's, natural gasoline, pentanes plus or C5+, that remains suspended in natural gas at the wellhead and is removed at a gas processing plant. For purposes of this report, both categories are included in the term "condensate.". Both categories of condensate are substantially similar in composition but the US EIA arbitrarily defines lease condensate as crude oil and plant condensate as an NGL (pentanes plus). Furthermore, Department of Commerce - Bureau of Industry and Security (BIS) regulations also define lease condensate as crude oil.
Crude oil (Conventional)	A mixture of pentanes and heavier hydrocarbons that is recovered or is recoverable at a well from an underground reservoir. It is liquid at the conditions under which its volumes is measured or estimated and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas, condensate, or bitumen.
Crude oil (heavy)	Crude oil is deemed, in this report, to be heavy crude oil if it has an API of 27° or less. No differentiation is made between sweet and sour crude oil that falls in the heavy category because heavy crude oil is generally sour.
Crude oil (medium)	Crude oil is deemed, in this report, to be medium crude oil if it has an API greater than 27° but less than 30°. No differentiation is made between sweet and sour crude oil that falls in the medium category because medium crude oil is generally sour.
Crude oil (synthetic)	A mixture of hydrocarbons, similar to crude oil, derived by upgrading bitumen from the oil sands.
Density	The mass of matter per unit volume.
DilBit	Bitumen that has been reduced in viscosity through addition of a diluent (or solvent) such as condensate or naphtha.
Diluent	Lighter viscosity petroleum products that are used to dilute bitumen for transportation in pipelines.
Extraction	A process unique to the oil sands industry, in which bitumen is separated from their source (oil sands).

Feedstock	In this report, feedstock refers to the raw material supplied to a refinery or oil sands upgrader.
Integrated mining project	A combined mining and upgrading operation where oil sands are mined from open pits. The bitumen is then separated from the sand and upgraded by a refining process.
<i>In Situ</i> recovery	The process of recovering crude bitumen from oil sands by drilling.
Merchant upgrader	Processing facilities that are not linked to any specific extraction project but is designed to accept raw bitumen on a contract basis from producers.
Oil	Condensate, crude oil, or a constituent of raw gas, condensate, or crude oil that is recovered in processing and is liquid at the conditions under which its volume is measured or estimated.
Oil sands	Refers to a mixture of sand and other rock materials containing crude bitumen or the crude bitumen contained in those sands.
Oil Sands Deposit	A natural reservoir containing or appearing to contain an accumulation of oil sands separated or appearing to be separated from any other such accumulation. The AER has designated three areas in Alberta as oil sands areas.
Oil Sands Heavy	In this report, Oil Sands Heavy includes upgraded heavy sour crude oil, and bitumen to which light oil fractions (i.e. diluent or upgraded crude oil) have been added in order to reduce its viscosity and density to meet pipeline specifications.
Open Season	A period of time designated by a pipeline company to determine shipper interest on a proposed project. Potential customers can indicate their interest/support by signing a transportation services agreement for capacity on the pipeline.
Pentanes Plus	A mixture mainly of pentanes and heavier hydrocarbons that ordinarily may contain some butanes and is obtained from the processing of raw gas, condensate or crude oil.
PADD	Petroleum Administration for Defense District that defines a market area for crude oil in the U.S.
Refined Petroleum Products	End products in the refining process (e.g. gasoline).
Specification	Defined properties of a crude oil or refined petroleum product.
SynBit	A blend of bitumen and synthetic crude oil that has similar properties to medium sour crude oil.
Train (Manifest)	Manifest trains carry multiple cargoes and make multiple stops. These are small group or single car load.
Train (Unit)	Unit trains carry a single cargo and deliver a single shipment to one destination, lowering the cost and shortening the trip.
Upgrading	The process that converts bitumen or heavy crude oil into a product with a lower density and viscosity.
West Texas Intermediate	WTI is a light sweet crude oil, produced in the United States, which is the benchmark grade of crude oil for North American price quotations.

APPENDIX A.1

CAPP Canadian Crude Oil Production Forecast 2015 – 2030

thousand barrels per day		Actual	Forecast																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																												
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Notes:

1. Atlantic Canada production includes Newfoundland & Labrador production and negligible volumes from New Brunswick. Condensates/pentanes from Nova Scotia and New Brunswick are also added.
2. CAPP allocates Saskatchewan Area III Medium crude as heavy crude. Also 17% of Area IV is > 900 kg/m³.

APPENDIX A.2 CAPP Western Canadian Crude Oil Supply Forecast 2015-2030

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

	Actual	Forecast																
		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CONVENTIONAL																		
Total Light and Medium		763	773	747	731	722	719	726	732	736	740	745	749	754	760	767	774	778
Net Conventional Heavy to Market		362	360	357	357	350	341	327	312	298	288	282	276	271	266	263	260	257
TOTAL CONVENTIONAL		1,125	1,133	1,104	1,088	1,071	1,060	1,053	1,043	1,033	1,028	1,027	1,025	1,024	1,026	1,029	1,034	1,035
OIL SANDS																		
Upgraded Light (Synthetic) ¹		756	796	820	844	918	929	964	977	982	968	951	932	916	908	1,012	1,038	1,070
Oil Sands Heavy ²		1,859	2,066	2,280	2,478	2,707	2,836	2,905	2,995	3,090	3,215	3,352	3,510	3,618	3,716	3,783	3,857	3,953
TOTAL OIL SANDS AND UPGRADERS		2,616	2,862	3,100	3,322	3,625	3,765	3,869	3,972	4,072	4,183	4,303	4,442	4,534	4,624	4,795	4,895	5,022
Total Light Supply		1,519	1,569	1,566	1,575	1,639	1,648	1,690	1,709	1,717	1,708	1,696	1,681	1,669	1,668	1,779	1,812	1,847
Total Heavy Supply		2,222	2,426	2,637	2,835	3,057	3,177	3,233	3,306	3,388	3,503	3,633	3,786	3,889	3,982	4,045	4,117	4,210
WESTERN CANADA OIL SUPPLY		3,741	3,995	4,204	4,410	4,696	4,825	4,922	5,015	5,105	5,211	5,329	5,467	5,558	5,650	5,824	5,929	6,058

Notes:

1. Includes upgraded conventional.

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

Supply numbers from operating and in construction projects only are not provided due to confidentiality concerns.

APPENDIX B ACRONYMS, ABBREVIATIONS, UNITS AND CONVERSION FACTORS

Acronyms

API	American Petroleum Institute
AER	Alberta Energy Regulator
CAPP	Canadian Association of Petroleum Producers
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
IEA	International Energy Agency
NEB	National Energy Board
OECD	Organization for Economic Co-operation and Development
PADD	Petroleum Administration for Defense District
U.S.	United States
WCSB	Western Canada Sedimentary Basin
WTI	West Texas Intermediate

Canadian Provincial Abbreviations

AB	Alberta
BC	British Columbia
MB	Manitoba
NB	New Brunswick
NL	Newfoundland & Labrador
NWT	Northwest Territories
ON	Ontario
QC	Québec
SK	Saskatchewan

Units

b/d	barrels per day
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Conversion Factor

1 cubic metre = 6.293 barrels (oil)

U.S. State Abbreviations

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

Crude Oil Pipelines and Refineries





CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS

For Information Contact: (403) 267-1141 / www.capp.ca

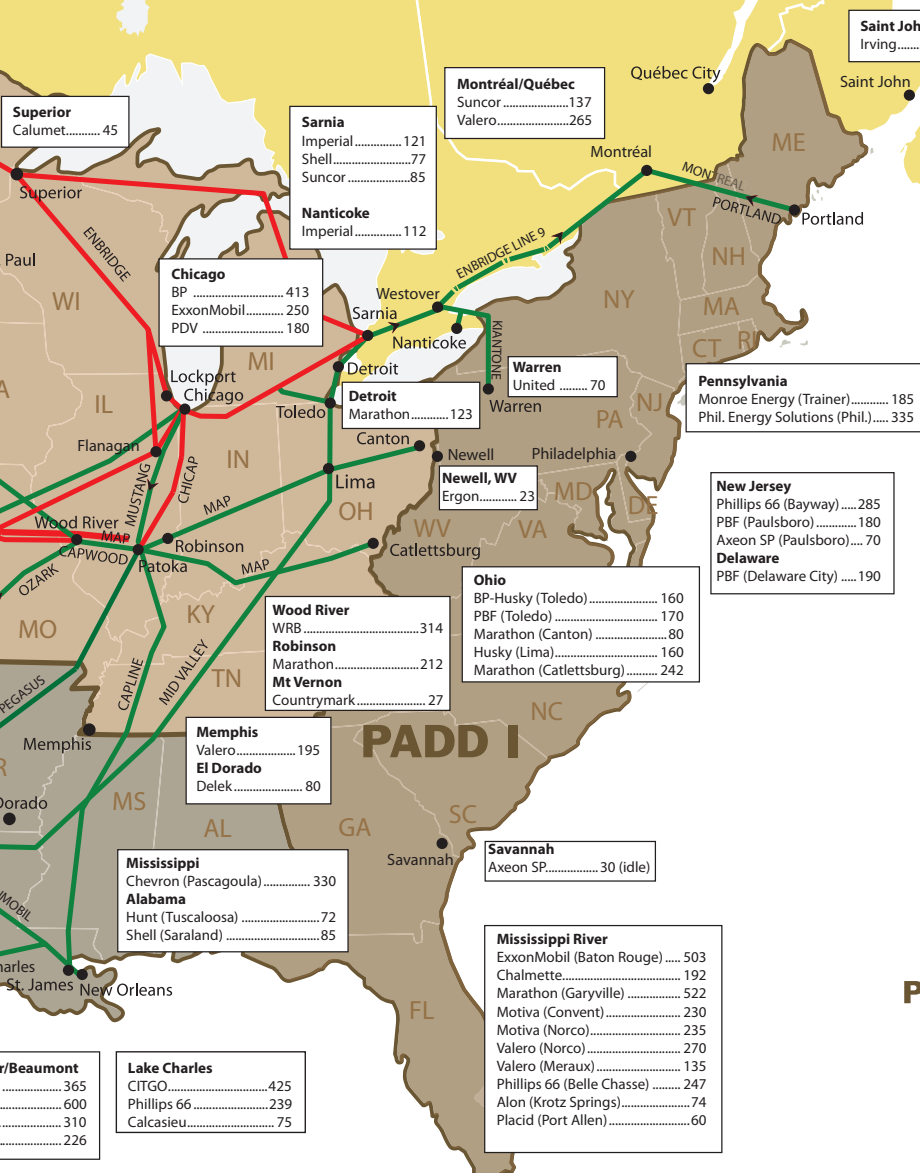
2014 Canadian Crude Oil Production		
	000 m ³ /d	000 b/d
British Columbia	8	49
Alberta	461	2,899
Saskatchewan	82	515
Manitoba	7	47
Northwest Territories	2	11
Western Canada	560	3,522
Eastern Canada	35	220
Total Canada	595	3,742

Newfoundland & Labrador

Silver Range (Come by Chance) 115

Come by Chance

Hibernia
Hebron
Terra Nova
White Rose



Pipeline Tolls for Light Oil (US\$ per barrel)

Edmonton to

Burnaby (Trans Mountain)	2.20
Anacortes (Trans Mountain/Puget)	2.50
Sarnia (Enbridge)	4.50
Chicago (Enbridge)	4.05
Wood River (Enbridge/Mustang/Capwood)	5.50
USGC (Enbridge/Seaway)	6.15†-11.10

Hardisty to

Guernsey (Express/Platte)	1.65*
Wood River (Express/Platte)	2.00*
Wood River (Keystone)	4.60**-5.20
USGC (Keystone/TC Gulf Coast)	6.95***-11.75

USEC to Montréal (Portland/Montréal)

1.40

St. James to Wood River (Capline/Capwood)

1.30

Pipeline Tolls for Heavy Oil (US\$ per barrel)

Hardisty to:

Chicago (Enbridge)	4.25
Cushing (Enbridge)	5.45*-6.80
Cushing (Keystone)	6.00**-6.80
Wood River (Enbridge/Mustang/Capwood)	6.15
Wood River (Keystone)	5.25**-5.90
Wood River (Express/Platte)	2.45*
USGC (Enbridge/Seaway)	6.95†-11.30
USGC (Keystone/TC Gulf Coast)	7.85***-12.75

Notes 1) Assumed exchange rate = 0.82 US\$ / 1C\$ (May 2015 average)

2) Tolls rounded to nearest 5 cents

3) Tolls in effect July 1, 2015

* 10-year committed toll

** 20-year committed toll

† First Open Season, 15-year, 50,000+ b/d committed volumes

Canadian and U.S. Crude Oil Pipelines and Refineries

Area Refineries - Capacities as at Jun 1, 2015
(in '000s barrels per day)

PADD

Petroleum Administration for
Defense District

Major Existing Crude Oil Pipelines carrying
Canadian crude oil

Selected Other Crude Oil Pipelines



CANADIAN ASSOCIATION
OF PETROLEUM PRODUCERS

Canada's Oil and Natural Gas Producers

The Canadian Association of Petroleum Producers (CAPP) represents companies, large and small, that explore for, develop and produce natural gas and crude oil throughout Canada. CAPP's member companies produce about 90 per cent of Canada's natural gas and crude oil. CAPP's associate members provide a wide range of services that support the upstream crude oil and natural gas industry. Together CAPP's members and associate members are an important part of a national industry with revenues from oil and natural gas production of about \$120 billion a year. CAPP's mission, on behalf of the Canadian upstream oil and gas industry, is to advocate for and enable economic competitiveness and safe, environmentally and socially responsible performance.



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