

## 2019 Crude Oil Forecast, Markets and Transportation





CAPP's annual *Crude Oil Forecast, Markets and Transportation* report provides a long-term outlook for Canadian crude oil production, and this year is projecting serious constraints over the forecast period from 2019 to 2035.





This constrained forecast is due to current cumulative regulatory and policy challenges and insufficient market access, which in turn are having and will continue to have negative impacts throughout Canada's economy – from diminishing investment to loss of employment and reduced government tax and royalty revenues.



The Canadian situation is in sharp contrast to growing energy demand and production elsewhere. **By 2040, global oil demand is anticipated to increase 12 per cent, to 106.3 million barrels per day (b/d).** Across the Asia Pacific region, oil consumption and refinery demand are growing significantly, and U.S. refinery demand is robust.

**Canada has an opportunity to gain global market share,** replacing less sustainably produced oil sources. At the same time, a healthy Canadian industry with access to global markets ensures ongoing prosperity and economic benefits across the country.

However, the industry continues to face numerous challenges. **If these challenges are not successfully addressed, any meaningful increase in oil production will not be achievable,** ultimately reducing potential growth in Canadian gross domestic product (GDP), business investment, exports, and jobs.

### Industry Competitiveness

Inefficient and duplicative regulations are diminishing the global competitiveness of Canada's crude oil industry. The Canadian oil sands industry is set to post its **fifth consecutive annual decline in investment.** The continued regulatory and policy challenges create significant barriers to future investment, putting Canadian jobs at risk.



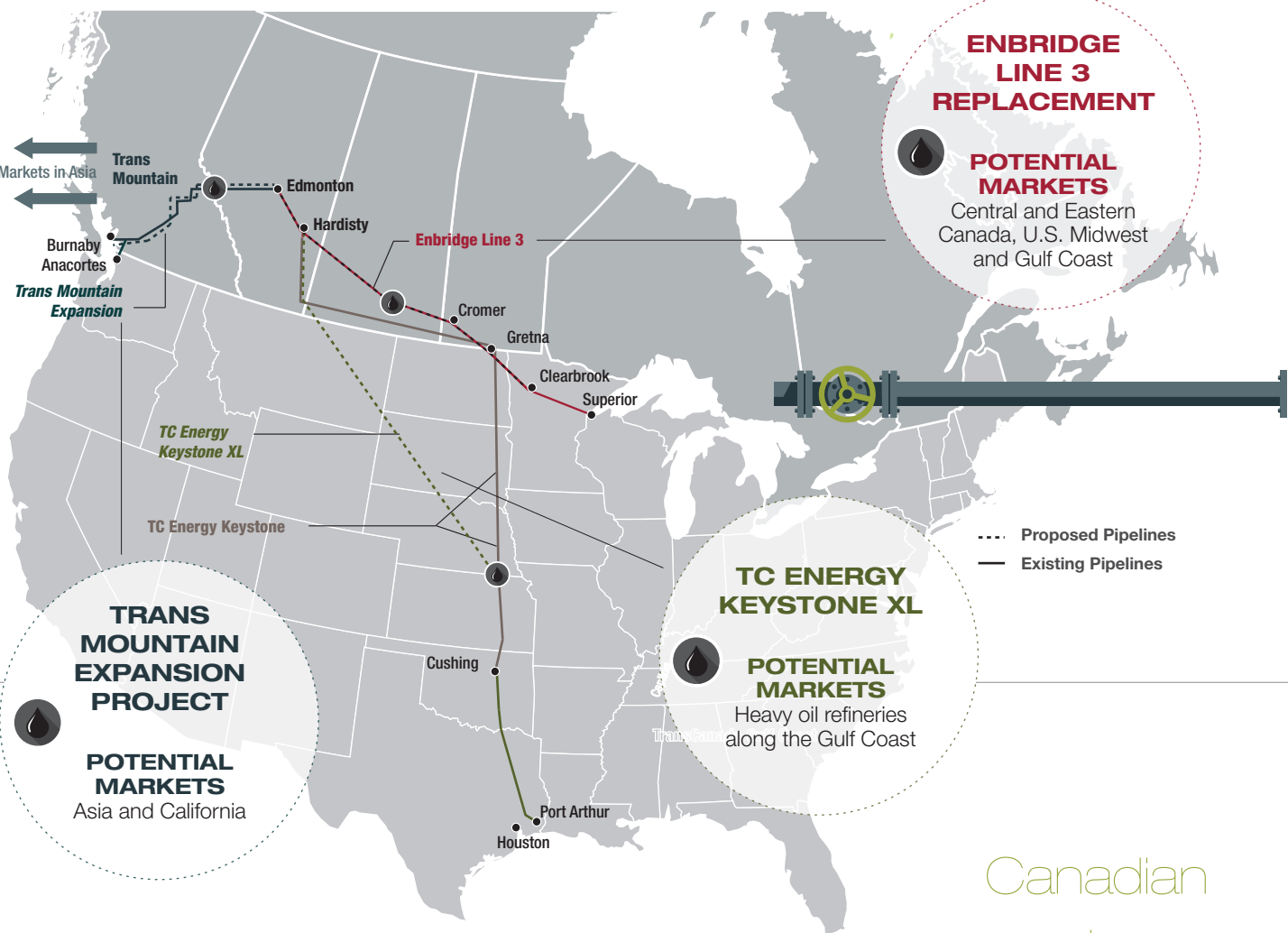
Additionally, while the U.S. has aggressively streamlined regulations and tax rates to promote its own oil industry, the competitiveness gap is being exacerbated by proposed Canadian federal legislation that CAPP believes will establish barriers to improved market access and will negatively affect investor confidence.

Canadian producers are faced with insufficient takeaway capacity for crude oil.



### Proposed Pipeline Projects Facing Regulatory and Legal Scrutiny

Source: CAPP



### Fair Market Value

Pipeline constraints and lack of market diversity also mean Canada is losing value for crude oil exports. Canadian producers are not benefiting from the global commodity price. **The key to obtaining better value for our resources in global markets is to build new, as well as improve existing infrastructure,** allowing Canadian energy to compete for emerging global markets.

Resolving current regulatory and policy barriers is essential to unlocking the future of Canada's energy industry – and indeed to Canada's future prosperity. Canada is in the unique position of having abundant natural resources but insufficient pipeline and other infrastructure to grow exports of Canadian oil to U.S. and global markets.

Canadian producers are not benefiting from the global commodity price.

Growth rate less than half



of 2014 outlook



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# INTRODUCTION

In this, the 2019 edition of the *Crude Oil Forecast, Markets and Transportation* report, the Canadian Association of Petroleum Producers (CAPP) provides a constrained outlook for Canadian oil production from 2019 to 2035, as producers face a broad and increasing array of challenges. If these challenges are not successfully addressed then any meaningful increase in oil production will not be achievable, ultimately reducing potential growth in Canadian GDP, business investment, exports, and jobs. Oil supply in Western Canada already exceeds the transport capacity of pipelines to serve external markets, with the result that Canadians are not receiving the full value for our resources. While rail will play an increasingly important role in transporting western Canadian crude oil to regional refinery centres, significant additional pipeline capacity is needed for the Canadian industry to capture growing oil demand.

In addition to meeting regional market opportunities in the United States, with improved takeaway capacity Canadian producers would have the ability to serve global markets and fully realize Canada's enormous resource potential. Improved pipeline capacity would allow Canadian producers to deliver increased volumes of heavy crude oil to the U.S. Gulf Coast at a time when other suppliers, such as Mexico and Venezuela, are reducing production of these crude varieties. Pipeline access from Western Canada to tidewater would provide Canadian producers with access to global markets, such as the Asia Pacific region, where growth in refinery feedstock demand is expected to be significantly higher than in North America. The ability for western Canadian crude oil to gain market share and to meet future increasing oil demand depends on the successful completion of new pipeline projects. The current lack of certainty of timing and confidence in completion of current pipeline projects, layered with additional regulatory issues, has led to a constrained production outlook.

Due to transportation costs and crude quality differences, heavier crude oils in Western Canada, such as Western Canadian Select (WCS), should typically expect to trade at a discount of about US\$12 per barrel against West Texas Intermediate (WTI), the North American crude oil benchmark which is traded at Cushing, OK. Approximately half of this discount is the result of quality differences between heavy and light oil; the remainder reflects the need for Canadian crude to be transported long distances to serve U.S. refineries. At times in 2018, however, this crude oil price differential exceeded US\$50 per barrel. This significantly larger differential was symptomatic of the lack of pipeline access out of the Western Canadian Sedimentary Basin (WCSB). Unable to find sufficient transportation for their production, producers consequently sold crude volumes at distressed prices, reducing producer revenues, government taxes and royalties collected, and hindering future investment. Surging levels of storage in Western Canada were also the result of a lack of transportation alternatives out of the region.

Other heavy oil producing countries are facing production declines due to aging infrastructure and geopolitical turmoil. This reduction in supply is leading to a better pricing environment for heavy crudes in markets such as the U.S. Gulf Coast where refineries are capable of processing heavy crudes. Canada is missing an opportunity not only to gain market share but also to receive premium pricing for our resources. In response to the significant price differentials in the fall of 2018, the Alberta government enacted its Crude Oil Curtailment Program that established limits on the volumes operators can produce in the province during 2019. The program's intent is to reduce aggregate production from the WCSB to a level that should allow producers to draw down storage while fully utilizing current egress capacity from Western Canada. Draining high inventories of crude that have built up while egress capacity from the basin has lagged production was seen by the government to be a critical component of correcting the large price differentials that emerged in the second half of 2018. Following the implementation

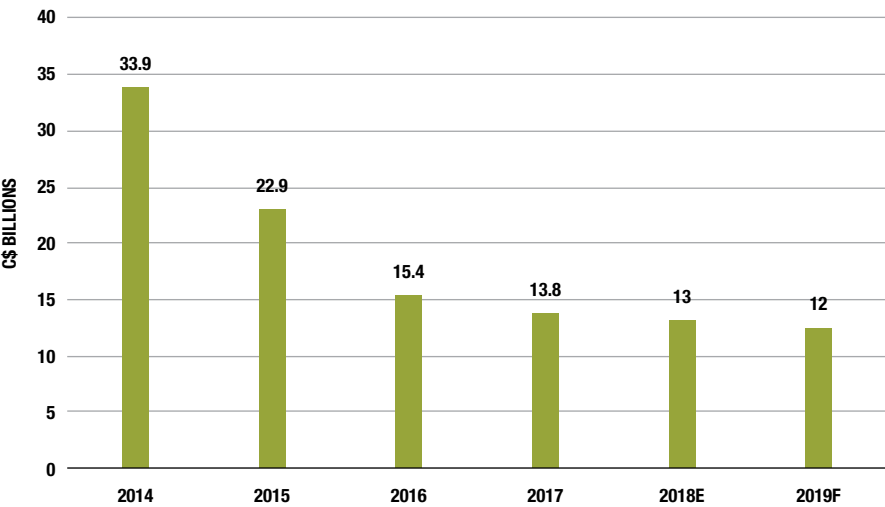


of the program, crude oil price differentials have narrowed significantly; however, curtailment is not a long-term solution.

Government initiatives such as the Crude Oil Curtailment Program create challenges when constructing a forecast for production, and can further constrain the outlook. While crude oil differentials might be reduced in the short run, production limits may directly affect firms’ drilling programs as they reduce capital spending on new wells to ensure they remain within curtailment limits. Similarly, oil sands operators may have to adjust the timing of additional projects or new phases in order to avoid exceeding curtailment limits.

The investment outlook in Western Canada is unfavourable due to the uncertainty from continual delays in obtaining increased market access. Delays and inefficient and duplicative regulations are affecting producers’ confidence and their willingness to invest in the region. The Bank of Canada continues to identify a lack of market access in the sector as a drag on the Canadian economy.<sup>1</sup> Conventional oil producers are expected to drill fewer wells in 2019 compared to either 2017 or 2018. Activity levels are not likely to show significant improvement without better market access. Capital spending in the oil sands is forecast to decline for a fifth consecutive year to \$12 billion, which is approximately one-third of the investment levels seen in 2014 (Figure 1.1). Canadian GDP has been reduced due to lack of business investment and falling exports directly tied to the oil and natural gas industry.

**Figure 1.1 Capital Investment in the Oil Sands**  
E = Estimate F = Forecast



Production from oil sands projects, which involve substantial long-term financial commitments, are key drivers in the future growth prospects for Canadian crude oil production. Companies have adjusted to the lower price oil environment by substantially reducing their cost structure by anywhere from 35 to 55 per cent.<sup>2</sup> Yet, investment continues to be reduced due to pipeline delays, regulatory issues and reduced competitiveness. Producers need certainty and defined timelines. Without these assurances, the global competitiveness of Canada’s oil industry will be diminished, creating a significant barrier to future investment and putting Canadian jobs at risk. Potential federal legislation that would shift project approvals into the federal realm would slow new developments, leading to even less investment and fewer jobs.

Without new pipeline capacity, producers are forced to move their product to markets using higher cost options such as rail, thereby driving up the discount in western Canadian oil prices.

# ENVIRONMENT, SOCIAL, GOVERNANCE (ESG): CONTINUOUS IMPROVEMENT

There is an increased interest regarding environmental, social and governance (ESG) practices in Canada. Oil producers are committed to (ESG) with an understanding that for the energy sector the (E) Environment is focal priority. Companies are committed to lowering GHG emissions while minimizing other environmental impacts, in line with corporate goals of cost control, operating efficiently and being sustainable community partners.

Good governance drives strong environmental and social practice – both corporately and from a jurisdictional perspective. Canada and Canadian companies consistently rank among the highest in international ESG scores.<sup>3</sup> Company focus and disclosure on ESG performance demonstrates awareness and management of material business risks and priorities for organizations.

A variety of research indicates that the oil sector is, in fact, a global leader in ESG practices, especially in the technology and innovation space:

- The average emissions intensity of oil extraction has fallen 21 per cent since 2009. Oil sands life-cycle emissions are nearing North American average values.
  - + By 2030, new technologies and efficiencies deployed in the oil sands could result in up to a 27 per cent reduction in the GHG intensity of steam-assisted gravity drainage operations and up to a 20 per cent reduction in the GHG intensity of mined oil sands.
  - + On a full life-cycle basis (emissions from production to combustion), such intensities would place these sources within two to four per cent, and five to seven per cent respectively, of the average emission intensity for crude oil refined in the U.S.<sup>4</sup>
- The Canadian industry will reduce methane emissions by 45 per cent from oil and natural gas operations by 2025.

Innovation and collaboration are hallmarks of the oil sands industry, which has established a number of organizations to fund research and share results. CAPP’s report *Competitive Climate Policy: Supporting Investment and Innovation* (May 2018) states:

- Canada’s Oil Sands Innovation Alliance (COSIA) launched in 2012, and as of March 2018 member companies shared more than 980 distinct technologies that cost more than \$1.4 billion to develop.
- Petroleum Technology Alliance Canada (PTAC) has launched more than 600 projects and has a roster of about 100 active research projects aimed at technology development.
- Clean Resources Innovation Network (CRIN) unites Canada’s resource industry, innovators, technology vendors, academia, research institutes, financing and government to accelerate the commercialization of innovative technologies.

CAPP’s report *Toward a Shared Future: Canada’s Indigenous Peoples and the Oil and Natural Gas Industry* (October 2018) found that:

- Between 2011 and 2016, the Fort McKay Group of Companies (Indigenous-owned businesses located in the oil sands region) generated more than \$2.3 billion in revenue, which has supported the community in becoming self-determining and a strong, active participant in the oil sands industry.
- In 2015 and 2016, oil sands companies spent \$3.3 billion in procurement from Indigenous-owned companies, provided \$48.6 million in Indigenous community investment and \$40.79 million to fund Indigenous consultation capacity.

A Joint Working Group (JWG) was convened in late 2017 as a forum for industry, federal and provincial governments to examine issues affecting competitiveness of Canada’s upstream oil and natural gas industry.<sup>5</sup> According to the JWG report the Canadian upstream petroleum industry’s workforce is becoming increasingly diverse. For example: a doubling of visible minorities; an increase of immigrants, to about 16 per cent of the sector’s workforce; six per cent of the workforce are Indigenous peoples, compared to four per cent for Canada’s overall workforce.



# CRUDE OIL PRODUCTION AND SUPPLY FORECAST

Over the next two decades, the world's population is expected to grow by nearly two billion while the global middle class is expected to nearly double.<sup>6,7</sup> Countries will be more urbanized and industrialized, and will consume more energy than today. Canada thus has the potential to become an even more significant supplier in meeting global crude oil demand. Canada is the world's sixth-largest oil producer and is home to a vast 170 billion barrels of crude oil reserves. However, the path to realizing this potential is paved with challenges regarding uncertainty as to when or whether additional pipeline capacity will become available.

Total Canadian oil production, including pentanes and condensate, is expected to rise to 5.86 million barrels per day (b/d) by 2035 from 4.59 million b/d in 2018. Due to the need to supplement domestic diluent supplies with imported volumes, the total supply from Western Canada is forecast to grow to 6.3 million b/d by 2035 from 4.7 million b/d in 2018. For comparison, in 2014 CAPP projected total supply from Western Canada would grow to 7.5 million b/d by 2030. This year's constrained production outlook is due to inefficient and duplicative regulations, reduced investor and producer confidence, and uncertainty around additional transportation capacity.

### 2.1 Production and Supply Forecast Methodology

CAPP's forecasts for western Canadian conventional production and eastern Canadian production were both developed through an internal analysis of historical trends, expected drilling activity, and discussions with industry stakeholders and government agencies.

To forecast oil sands production, CAPP surveyed oil sands producers in the first quarter of 2019 requesting the following information:

- Expected production for each project;
- Upgraded crude oil production volumes;
- Type and volume of diluent required to move heavy oil production to market.

Producers were asked to respond to the survey based on their company's view of the price outlook, as well as recent policy developments including federal and provincial climate policies and the impacts of Alberta's Crude Oil Curtailment Program. The survey results were risk adjusted by taking into consideration each project's stage of development, (i.e. announced, approved, under construction, operating) while giving consideration to each company's past performance for previous phases of projects relative to public announcements. The reasonableness of the overall forecast was then assessed against historical trends. No constraints were imposed to reflect any restrictions on the availability of condensate for blending purposes or the lack of transportation infrastructure, although company assessments on these issues may have impacted individual producer survey responses.

The volume of total crude oil supply delivered to pipelines and markets is greater than total production because imported diluent, in addition to domestic supplies, is needed to meet the blending requirements that enable heavy oil to be transportable by pipeline.

### 2.2 Canadian Production

Conventional crude oil is produced across the western Canadian provinces while the oil sands are located only in Alberta. Eastern Canada produces limited amounts of crude oil primarily from projects located offshore of Newfoundland and Labrador.

Of the 4.6 million b/d of Canadian production in 2018, Eastern Canada contributed 233,000 b/d, meaning western Canadian production contributed over 95 per cent of the total. Nearly two-thirds was comprised of oil sands production and the remainder, including pentanes and condensate, was from conventional production. By the end of the outlook period, oil sands production is expected to account for nearly 75 per cent of total production (Figure 2.1).

Figure 2.1 Canadian Oil Sands and Conventional Production

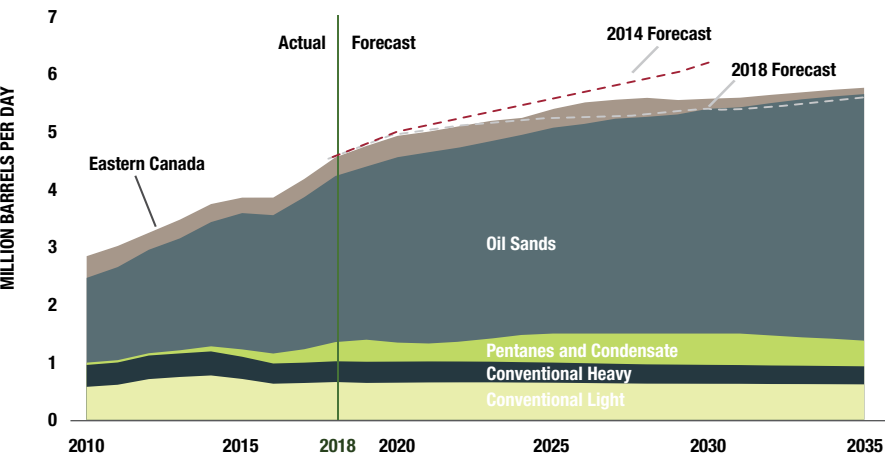


Table 2.1 Canadian Crude Oil Production

Million b/d	2018	2020	2025	2030	2035	Change
Eastern Canada	0.23	0.30	0.32	0.18	0.09	-0.14
Western Canada	4.36	4.64	5.17	5.48	5.76	1.41
Total Canada*	4.59	4.94	5.49	5.66	5.86	1.27

\*Totals may not add up due to rounding

Production in Eastern Canada is forecast to peak at 354,000 b/d in 2026 before falling to roughly 91,000 b/d in 2035. Production growth in Western Canada is expected to more than offset this decline, as it is forecast to increase by more than 1.4 million b/d, reaching 5.76 million b/d in 2035 from 4.36 million b/d in 2018 (Table 2.1).

### 2.3 Eastern Canada Production

Ontario and New Brunswick produce small volumes of crude oil; however, most of the crude oil from Eastern Canada is produced from offshore Newfoundland and Labrador. Hibernia, Terra Nova, White Rose and Hebron are the four major offshore projects currently producing oil. The growth forecast for production in Eastern Canada through 2024 can largely be attributed to production ramping up from Hebron, the newest major offshore project, and satellite field additions to other existing projects. At its peak, Hebron is designed to produce 150,000 b/d.

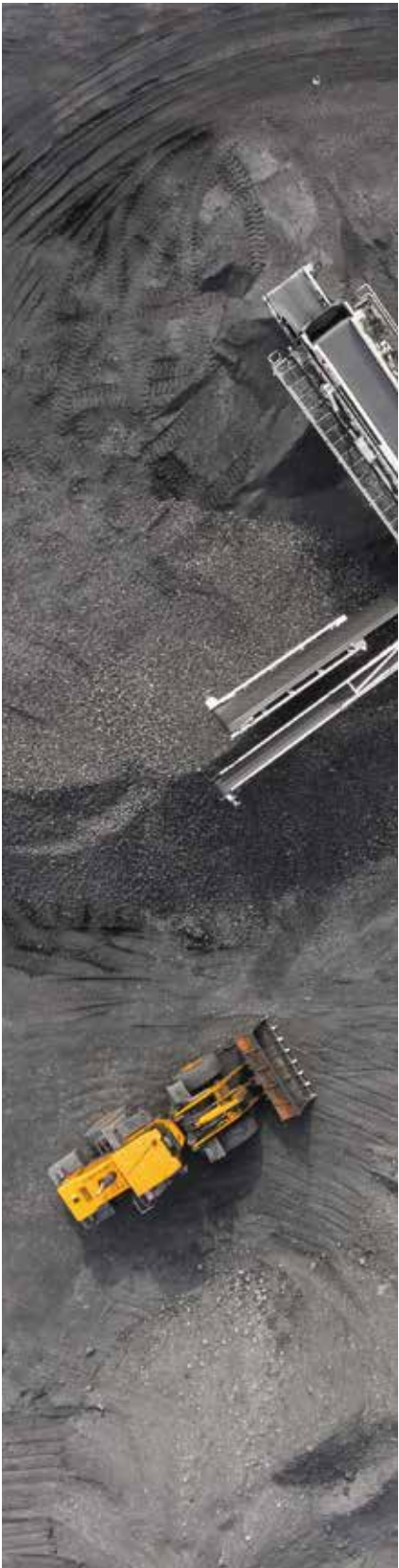


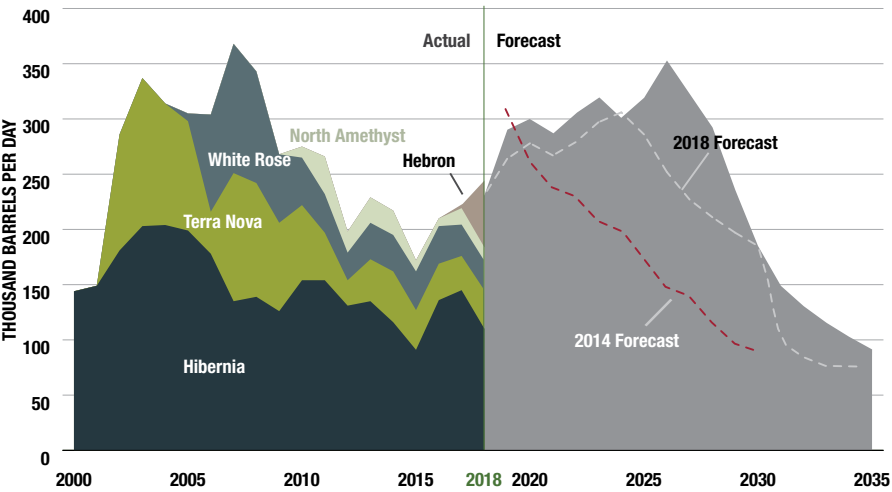


Table 2.2 Atlantic Canada Projects and Recent Discoveries

Source: Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB)

Producing field	Cumulative Production to December 2018 (millions of barrels)	Estimated Recoverable Reserves (millions of barrels)
Hibernia	1055 (67% of reserves)	1,644
Terra Nova	402 (82% of reserves)	506
White Rose and North Amethyst	285 (62% of reserves)	479
Hebron	23 (3% of reserves)	707
Recent Discoveries	Year Discovered	Estimated Recoverable Reserves (millions of barrels)
Mizzen	2009	102 (heavy oil)
Harpoon	2013	Under Evaluation
Bay du Nord	2013	300 - 600 (light oil)

Figure 2.2 Newfoundland and Labrador Production



High decline rates are associated with offshore drilling as the large upfront capital costs and fixed operating costs incent maximizing production. However, while production from mature fields is expected to decline quickly, production from associated satellite pools can extend the lives of the projects and slow the overall rate of decline. Relative to last year’s forecast, CAPP anticipates existing projects will be slightly more productive through 2024 than previously projected. It is probable that an additional new project could achieve first oil in 2025, boosting the production profile through the latter half of the forecast period (Figure 2.2).

2.4 Western Canada Production

Western Canada provides 95 per cent of Canada’s total production. The oil sands contributed nearly two-thirds of the 4.36 million b/d produced in Western Canada in 2018, and will be responsible for the 1.41 million b/d of growth anticipated by 2035 (Table 2.3). Conventional production, including pentanes and condensate, will be stable and is forecast to contribute an average of more than one million b/d annually through the forecast period.

Table 2.3 Western Canada Crude Oil Production

Million b/d	2018	2020	2025	2030	2035	Change
Conventional	1.44	1.45	1.59	1.60	1.51	0.07
Crude oil	1.04	0.99	1.00	0.98	0.95	(0.09)
Pentanes and Condensate	0.41	0.45	0.59	0.61	0.56	0.16
Oil sands						
Bitumen + Upgraded	2.91	3.20	3.57	3.88	4.25	1.34
Total Western Canada*	4.36	4.64	5.17	5.48	5.76	1.41

\*Totals may not add up due to rounding

2.4.1 Conventional

In 2018, Western Canada saw 1.44 million b/d of conventional production, including 405,000 b/d of pentanes and condensate. Excluding pentanes and condensate, conventional crude oil production is expected to decline slightly over the forecast period. The level of drilling in Western Canada is at depressed levels resulting from market access constraints. However, improvements in market access as a result of additional pipeline and rail capacity would enable producers to more fully develop the tremendous resource opportunities available in the WCSB. As natural gas producers increasingly focus their efforts in the liquids-rich Montney and Duvernay plays, pentanes and condensate production from Western Canada is forecast to grow significantly, exceeding more than 600,000 b/d prior to the end of the forecast period before declining slightly in later years, as a result of current technological limitations combined with ongoing field maturity.

Crude Oil

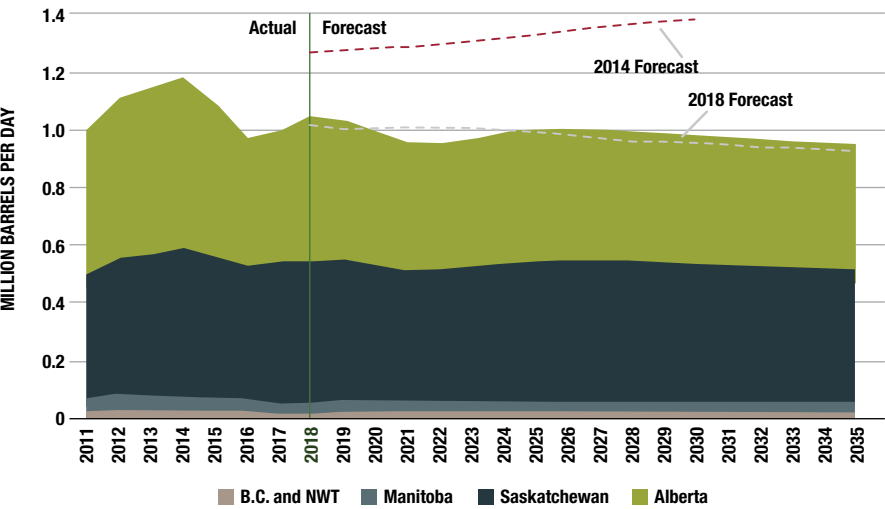
In 2018, the combined production from Alberta and Saskatchewan accounted for 95 per cent of the total 1.44 million b/d of conventional crude oil produced in Western Canada. British Columbia and Manitoba produce relatively small volumes. The National Energy Board (NEB) estimates that the region could hold as much as 8.5 billion barrels of remaining conventional crude oil resources; however, a lack of infrastructure and pipelines means these resources have insufficient market access. Crude oil resources are also located in the Northwest Territories, however, the relatively small amounts of conventional production from this region ceased altogether in 2017, due to the temporary shutdown of Enbridge’s Line 21. Production restarted in late 2018 when Line 21 was put back into service.

Conventional crude oil production tends to respond more quickly to changes in crude oil prices than oil sands production, given the smaller scale of these developments. Excessive price differentials arising from market access constraints have negatively affected producers’ desire to invest in new wells in the WCSB. Government initiatives such as the Crude Oil Curtailment Program may also discourage additional wells if producers are concerned about remaining within their production limits. This forecast assumes the pace of drilling oil wells in Western Canada recovers somewhat from today’s depressed levels. However, this anticipated increase in drilling activity remains constrained due to regulatory challenges, markets access constraints, and reduced competitiveness relative to other oil-producing countries. By 2035, conventional crude oil production excluding pentanes and condensate is anticipated to be eight per cent lower than it was in 2018.





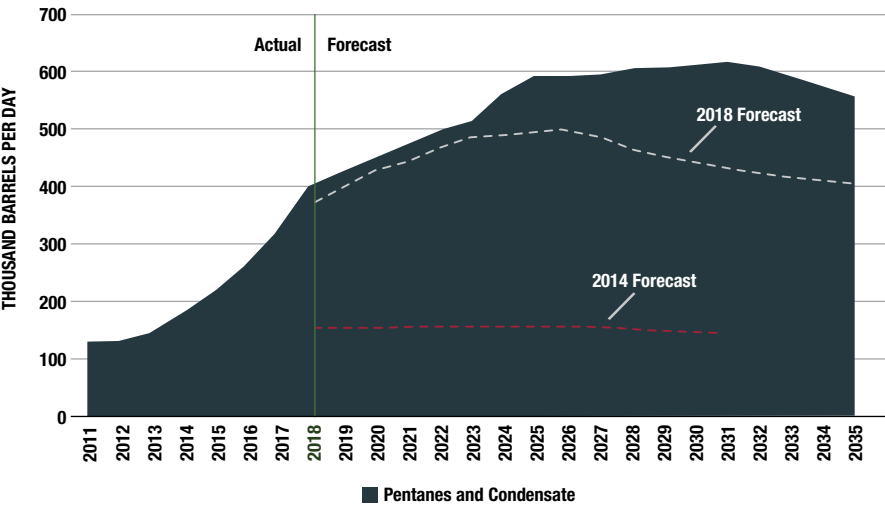
Figure 2.3 Western Canada Conventional Crude Oil Production



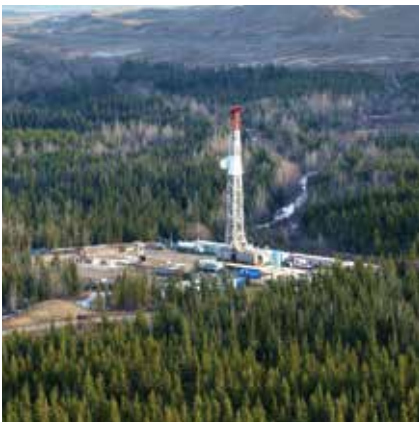
Pentanes and Condensate

Pentanes and condensate are the preferred diluent for blending with heavy oil and bitumen to enable transportation via pipeline. In 2018, 405,000 b/d of pentanes and condensate were produced in Western Canada, with about 80 per cent contributed by Alberta and 20 per cent contributed by B.C. Demand for pentanes and condensate from oil sands for blending with bitumen exceeds domestic production and demand will continue be driven by projected growth in heavy crude oil production. From 2014 to 2018, pentanes and condensate production more than doubled. This was due to the strong demand for diluent from oil sands producers and the presence of prolific liquids-rich natural gas plays in the Montney and Duvernay formations. Production of pentanes and condensate is forecast to grow significantly and achieve more than 600,000 b/d before the end of the forecast period. In the longer term, however, declines are anticipated as these fields mature.

Figure 2.4 Western Canadian Pentanes and Condensate Production



Production of pentanes and condensate is forecast to grow significantly.



2.4.2 Oil Sands

The oil sands resources are situated almost entirely in Alberta and can be delineated by the Athabasca, Cold Lake and Peace River deposits (Figure 2.5). In this constrained environment, oil sands production, which can be recovered either by mining or in situ projects, is forecast to grow by 1.34 million b/d, reaching 4.25 million b/d by 2035 from 2.91 million in 2018. From 2019 to 2021, annual oil sands production growth is expected to average four per cent. This growth rate, however, is less than half that of 2017 and 2018. Given the current regulatory environment and producers’ lack of confidence in market access alleviation, from 2022 onward the average production growth in the oil sands is expected to be only two per cent annually.

Mining projects are large-scale in nature and require more upfront capital than smaller scale in situ projects, where production can be brought on in phases. The Fort Hills mining project started continuous production in January 2018 and ramped up to just over 200,000 b/d in December. By 2035, production from mining operations will grow by 470,000 b/d (Table 2.4). In situ production is forecast to yield 880,000 b/d of additional production (Figure 2.6) by 2035. Part of this includes CNOOC International’s expansion at Long Lake, proposed to add 26,000 b/d, and Imperial Oil Limited’s Aspen project, which Imperial expects will begin production in 2023 and add 75,000 b/d.

Table 2.4 Oil Sands Production

Million b/d	2018	2020	2025	2030	2035	Change
Mining	1.35	1.51	1.63	1.72	1.82	0.47
In Situ	1.56	1.68	1.95	2.16	2.44	0.88
Total Oil Sands*	2.91	3.20	3.57	3.88	4.25	1.34

\*Totals may not add up due to rounding

Figure 2.6 Western Canada Oil Sands Production

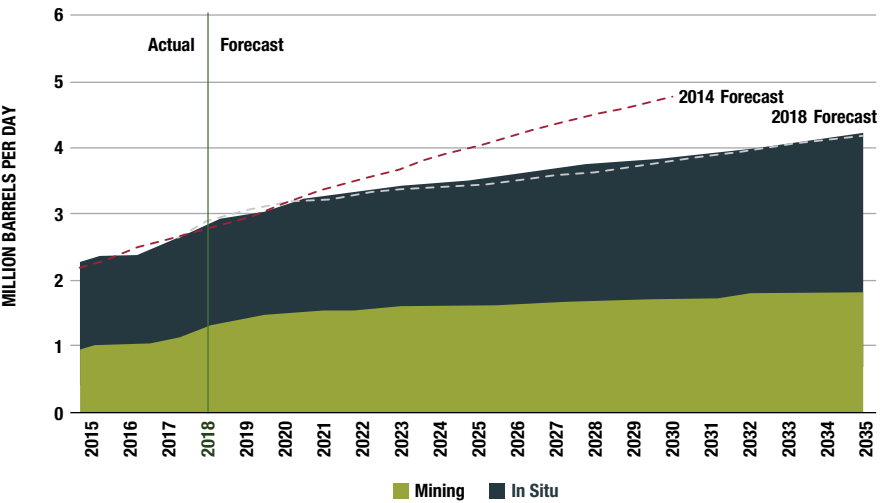


Figure 2.5 Oil Sands Regions



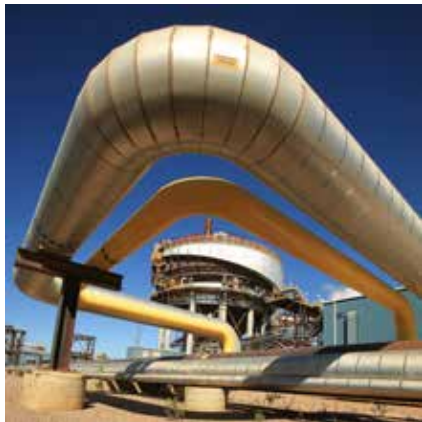


Curtailment

In December 2018, the Government of Alberta announced its Crude Oil Curtailment Program that was applied to production commencing in January 2019 and will terminate on December 31, 2019. Initially the program limited production in Alberta to 3.56 million b/d with the intention to create enough shipping space to clear the large buildup of storage volumes that had occurred in the province. Once storage volumes have been substantially reduced, the program intends to allow higher production limits for the balance of 2019.

Curtailment is only applied to operator volumes in excess of 10,000 b/d and as such will have limited impacts on small producers. While these cuts may affect some of the larger conventional producers, the majority of the impact is expected to affect oil sands producers, which typically have larger scale developments. Responding to market conditions and producer concerns regarding the safety issues surrounding cutting production, the government raised the production ceiling for the month of June to more than 3.7 million b/d.

This policy is a direct result of continued regulatory delay resulting in a lack of market access. The dramatically lower pace of growth in production at the latter end of the forecast period, relative to recent history and the near-term outlook, is the product of the industry's concerns around slow progress on new pipeline capacity and heightened levels of regulatory uncertainty. In addition, Canada's fiscal and tax policies have been diverging from those in the U.S., resulting in challenges for Canadian producers competing with their American counterparts to attract investment capital.



Upgrading

The production volumes from oil sands projects are derived by combining raw bitumen production and upgraded crude oil production from integrated projects. By volume, there is generally a yield loss associated with the upgrading process, which converts mined bitumen into an upgraded (lighter) crude oil. The yield losses associated with upgrading volumes from oil sands projects without associated upgraders is accounted for in the calculation of supply volumes discussed in Part 2.5 below. Refer to Appendix A.1 for detailed production data. Since CNOOC International idled the upgrader at its Long Lake in situ project in July 2016, there are no in situ projects with integrated upgrader facilities. Some in situ volumes from Suncor's Firebag and Mackay River projects can be upgraded at its Millennium mine upgrader but, in general, upgraders at smaller in situ operations are not considered economical.

The following is a list of the existing integrated mining and upgrading projects:

- Canadian Natural Resources' (CNRL) Albian Sands, which includes the Muskeg River and Jackpine mines;
- CNRL's Horizon mine;
- Suncor's Steepbank and Millennium mines;
- Syncrude Canada's Mildred Lake and Aurora mines.

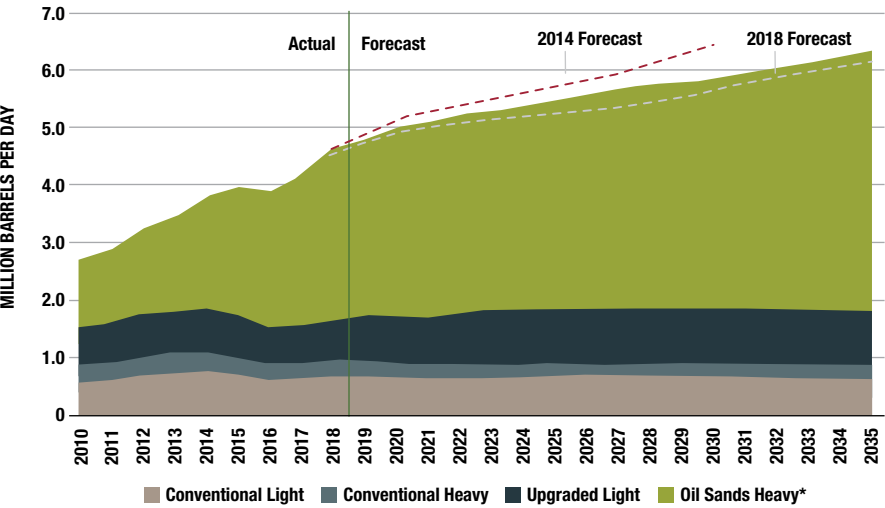
Imperial's Kearl mine and Suncor's newly operating Fort Hills mine are both stand-alone mines with no associated upgrading facilities.

Partial upgrading technology produces a medium or heavy crude oil that reduces the requirement for diluent volumes for blending. However, since partial upgrading technologies are still being assessed and haven't been commercially implemented in Canada, this technology is not anticipated to have an impact on production in the near- and medium-terms.

2.5 Western Canada Supply

Crude oil supply refers to the crude oil that is delivered to the end-use market. Conventional supply is projected to decline to 867,000 b/d in 2035 from 960,000 b/d in 2018. Upgraded light crude oil supply is expected to be stable and is forecast to average 948,000 b/d over the outlook period. Oil Sands heavy supply will grow by 1.52 million b/d to reach 4.5 million b/d in 2035 from 2.98 million b/d in 2018 (Figure 2.7).

Figure 2.7 Western Canada Oil Sands and Conventional Supply



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

On a volumetric basis, supply volumes reported in Appendix A.2 are greater than the corresponding production shown in Appendix A.1 because the addition of imported diluent volumes supplement domestic supplies used for blending both conventional heavy crude oil and oil sands bitumen that is not upgraded.

Pentanes and condensate are the main sources of diluent, and when combined with bitumen result in a heavy crude oil mixture known as "dilbit." Imports of condensate supplement domestic supplies and compensate for the shortfall between this blending demand and available domestic supplies. Synthetic bitumen, or "synbit" results when other bitumen volumes are diluted with upgraded light crude oil. Blending for dilbit requires about a 70:30 bitumen to condensate blending ratio, while synbit requires approximately a 50:50 ratio. Relatively small volumes of bitumen with a reduced diluent requirement is referred to as "railbit."

CAPP's forecast is not constrained by the availability of condensate imports, as CAPP assumes new sources of condensate will be available to meet market requirements. Western Canadian pentanes and condensate production is growing, but in 2018 458,000 b/d of imported condensate, upgraded crude oil, and butane were still needed for blending.





Table 2.5 shows the projections for total western Canadian crude oil supply. Total supply grows by almost 1.7 million b/d and reaches 6.34 million b/d from 4.66 million b/d in 2018. The growth is primarily driven by an increase in heavy crude oil supplies.

Table 2.5 Western Canada Crude Oil Supply

Million b/d	2018	2020	2025	2030	2035	Change
Light	1.40	1.49	1.62	1.64	1.61	0.21
Heavy	3.26	3.52	3.85	4.23	4.73	1.47
Total supply*	4.66	5.00	5.47	5.87	6.34	1.68

\*Totals may not add up due to rounding

2.6 Crude Oil Production and Supply Summary

In addition to the oil sands, the vast majority of Canada’s major conventional resources are concentrated in Western Canada. Eastern Canada has some crude oil production generated primarily from offshore projects.

- Production from Eastern Canada is forecast to grow and contribute over 350,000 b/d by 2026, but will subsequently fall to 91,000 b/d by 2035.
- Due to the constrained regulatory environment, growth from western Canadian oil sands production will increase by four per cent on average from 2019 to 2021 and after 2022 will slow to two per cent annually.
- Western Canada’s conventional crude oil production, including pentanes and condensate, increases from 1.4 million b/d in 2018 to 1.5 million b/d in 2035. Pentanes and condensate production in Western Canada peaks at more than 600,000 b/d reflecting the higher potential for production from liquids-rich natural gas plays.
- Almost 1.7 million b/d of additional western Canadian crude oil supply is forecast by 2035. This additional supply of conventional and oil sands production, combined with diluent volumes to meet blending requirements will need substantial amounts of additional pipeline capacity.

The long-term pace of growth in the oil sands continues to be hampered by uncertainty and delays related to new pipeline capacity out of Western Canada. Such constraints on production will have negative implications if the Canadian economy is prevented from receiving the full potential business investment, exports, and job growth associated with an unconstrained production outlook that this tremendous resource base offers.

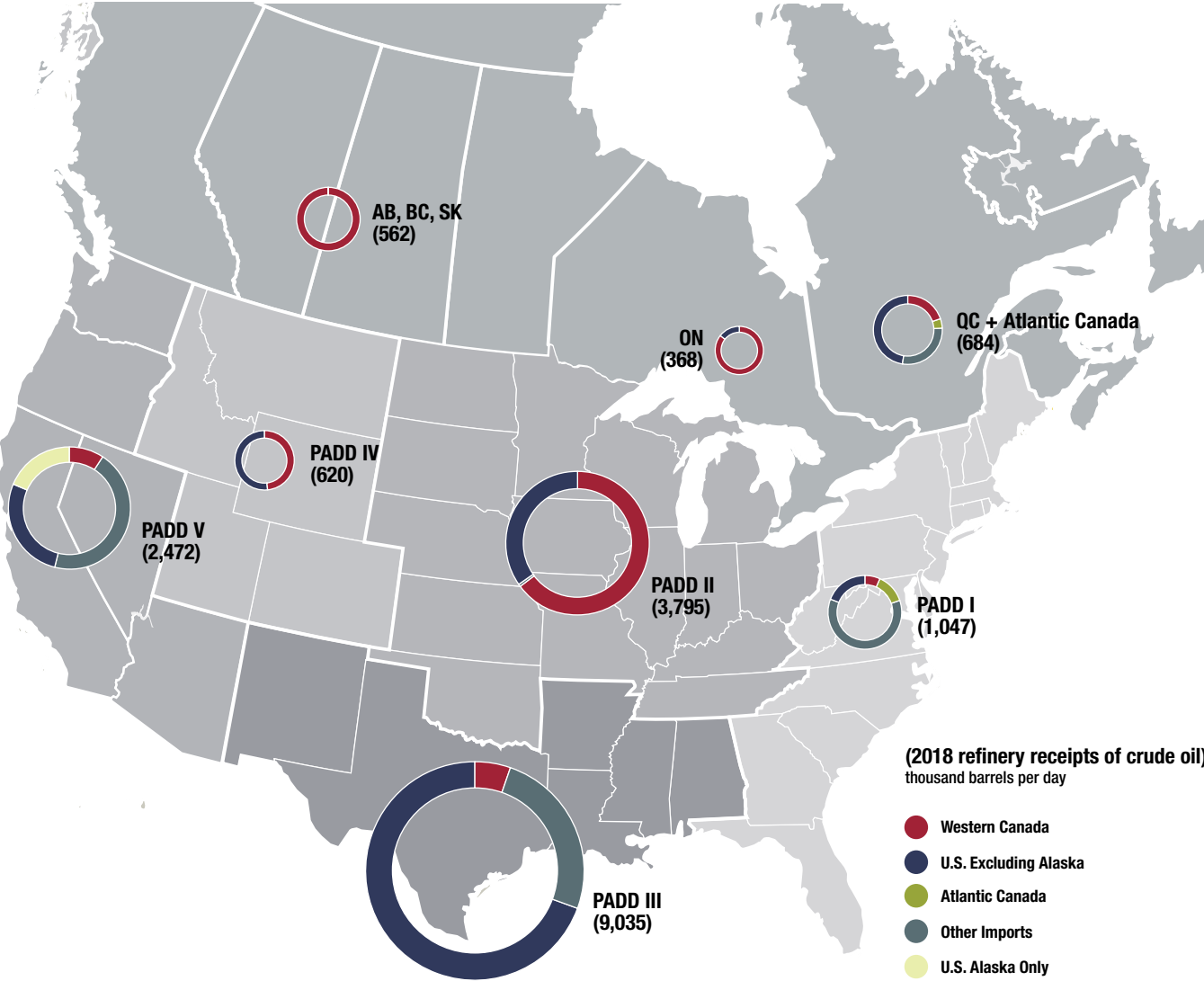
The long-term pace of growth in the oil sands continues to be hampered by uncertainty and delays to new pipeline capacity out of Western Canada.

CRUDE OIL MARKETS

Today nearly all of Canada’s oil exports are delivered to U.S. refineries. In 2018, Canada exported more than 3.6 million b/d to the U.S. – less than one per cent of exports were delivered to other markets. Domestic Canadian refinery markets account for about one million b/d, or 24 per cent of total demand for Canadian production.

Figure 3.1 shows the relative sizes of the regional refinery markets in the U.S. and their respective sources for crude oil supplies. Refineries receive crude oil feedstock and process it into a variety of petroleum products such as transportation fuels such as gasoline, diesel, jet fuel, and even some heating fuels. The volume of total crude oil supply delivered to pipelines and markets is greater than total production because imported diluent, in addition to domestic supplies, is needed to meet the blending requirements that enable heavy oil to be transportable by pipeline.

Figure 3.1 Canada and U.S. 2018 Crude Oil Receipts by Source  
Source: CAPP, CA Energy Commission, EIA, NEB, Statistics Canada





3.1 Canada

There are 17 refineries in Canada that have a collective crude oil refining capacity of 2.0 million b/d. In 2018, crude oil feedstock actually processed by Canadian refineries totaled more than 1.7 million b/d, including 593,000 b/d of imported oil.

3.1.1 Western Canada

The nine refineries located in Western Canada (Table 3.1) comprise approximately 40 per cent of Canada’s total crude oil refining capacity. Alberta and Saskatchewan refineries receive crude oil supplies exclusively from Western Canada, primarily by pipeline although some volumes are transported short distances by truck. Refineries in B.C. obtain some crude oil from within the province but most of B.C.’s supply comes from Alberta through the existing Trans Mountain pipeline, as well as some smaller volumes by rail. According to the NEB, less than 10 per cent of B.C.’s refined petroleum products are imported from the U.S.

Table 3.1 Refineries in Western Canada by Province

Owner	Location	Crude oil processing capacity (b/d)
<b>Alberta</b>		
Imperial	Strathcona	191,000
Husky (asphalt plant)	Lloydminster	290,00
Suncor	Edmonton	142,000
Shell	Scotford	92,000
North West Redwater Partnership	Sturgeon County	79,000 (dilbit)
Alberta subtotal (5 refineries)		533,000
<b>British Columbia</b>		
Parkland Fuel	Burnaby	55,000
Husky	Prince George	12,000
British Columbia subtotal (2 refineries)		67,000
<b>Saskatchewan</b>		
Federated Co-operatives	Regina	130,000
Gibson (asphalt plant)	Moose Jaw	18,000
Saskatchewan subtotal (2 refineries)		148,000
Total (9 refineries)		748,000

Western Canada refinery demand increased to 562,000 b/d in 2018 from 545,000 b/d in 2017 due to the start-up of Phase One of the North West Redwater Partnership’s Sturgeon Refinery, which commenced operations in late 2018. Since start-up, the refinery has processed synthetic crude oil to produce diesel. The refinery is working toward eventually processing heavier feedstocks; once construction of its gasifier is complete, the refinery will be able to use up to 50,000 b/d of bitumen or 79,000 b/d of dilbit as feedstock. This is the first refinery built in Canada since 1984 and has three potential expansion phases. Future expansions have received regulatory approvals but timing of the remaining phases is uncertain.



3.1.2 Eastern Canada

There are eight refineries in Eastern Canada with a combined crude oil refining capacity of 1.2 million b/d (Table 3.2). The capacity of these refineries exceeds the combined capacity of Canada’s western refineries by 464,000 b/d. Because eastern refineries are not as well connected to domestic crude oil production supplies, these refineries are currently more reliant on imported crude to meet their needs. Refineries in Eastern Canada process primarily light crude oil and in 2018 received approximately half of their 1.1 million b/d of feedstock from foreign sources.

Eastern refineries’ access to western Canadian supplies and U.S. Bakken production significantly improved after Enbridge reversed its Line 9 pipeline to flow west to east from Sarnia, Ontario to Montréal, Québec. This reversal occurred in December 2015.

Refineries in Québec and Atlantic Canada have tidewater access and consequently have access to crude oil supplies from a number of global alternatives. Irving Oil’s refinery in Saint John, N.B. can receive some western Canadian crude oil by rail, but Atlantic Canada refineries primarily rely on foreign imports by tanker, supplemented by some Atlantic Canada production. The U.S. has been a large supplier of crude oil to Canada since 2013, and supplied about 65 per cent of the total import demand in 2018. Saudi Arabia is also a major exporter of crude oil to eastern Canadian refineries, supplying 21 per cent of total import demand in 2018. Other countries supplying crude oil to these refineries include Nigeria, Azerbaijan and Norway.

Table 3.2 Refineries in Eastern Canada by Province

Owner	Location	Crude oil processing capacity (b/d)
<b>Ontario</b>		
Imperial	Nanticoke	113,000
Imperial	Sarnia	119,000
Shell	Sarnia	73,000
Suncor	Sarnia	85,000
Ontario subtotal (4 refineries)		390,000
<b>Quebec</b>		
Suncor	Montreal	137,000
Ultramar	Quebec City	23,5000
Quebec subtotal (2 refineries)		372,000
<b>Atlantic Canada</b>		
Irving	Saint John, NB	320,000
Silverpeak (North Atlantic Refining LP)	Come by Chance, NL	130,000
Atlantic subtotal (2 refineries)		450,000
Total (8 refineries)		1,212,000





3.2 United States Key Refining Hubs

Canada is the largest foreign supplier of crude oil to the U.S., delivering 3.7 million b/d in 2018, which accounted for almost all of Canada’s exports. Given its tremendous resource base, Canada has the potential to supply even larger volumes to the U.S. However, the ability to increase exports to this market is currently hampered by a lack of transportation capacity.

The U.S. Department of Energy divides the 50 states into five market regions called Petroleum Administration of Defense Districts (PADDs). These PADDs were originally created in the Second World War to help allocate fuels derived from petroleum products. Today, this delineation continues to be used when reporting data to describe U.S. crude oil markets, which have different characteristics attributable to their distinct regional locations.

3.2.1 PADD II – Midwest

Currently the largest regional market in the U.S. for Canadian crude oil exports is the Midwest. In 2018, this 3.8 million b/d refining market imported 2.5 million b/d, or 65 per cent of its crude oil feedstock needs (Figure 3.2) with almost all these imports originating in Western Canada.

This heavy reliance on crude supplies from Western Canada is not surprising, as a number of refineries in PADD II have made significant investments in recent years to increase their ability to process heavy crude oil. Consequently, these refineries are expected to continue to rely almost exclusively on Western Canada for their heavy feedstock requirements, as they are well connected via pipeline to access crude oil from Western Canada.

PADD II also encompasses the largest commercial storage hub in the U.S. at Cushing, Oklahoma. Cushing is the main trading hub for U.S. crude oil and is also the delivery point for New York Mercantile Exchange (NYMEX) traded futures contracts. The Energy Information Agency reports there are approximately 77 million barrels of working storage capacity at this hub. Crude oil that is initially delivered to this hub can ultimately be delivered to markets outside PADD II when taken out of storage. In recent years, additional pipeline capacity has been developed that connects this hub to refineries on the U.S. Gulf Coast, which are located in PADD III. Other primary market hubs within PADD II are located at Clearbrook, Minnesota and Wood River-Patoka, Illinois.

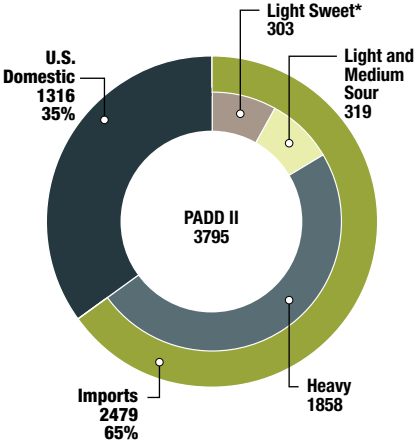
See Appendix C refinery map for locations.

3.2.2 PADD III - U.S. Gulf Coast

The U.S. Gulf Coast is home to a vast refinery complex that comprises 49 refineries with a combined capacity of 9.8 million b/d. The majority of this capacity is located in two coastal states, Louisiana and Texas.

Since 2010, U.S. consumption of domestic crude oil feedstock in the U.S. Gulf Coast has grown dramatically, as the U.S. has seen a significant increase in production from its own tight shale oil resources. For example, since 2007 the Permian basin has seen a fourfold increase in production, from less than one million b/d in to more than four million b/d in early 2019. In 2018, domestic crude oil supplied 6.3 million b/d, or

Figure 3.2 PADD II  
CRUDE OIL REFINING CAPACITY = 4089  
(THOUSANDS OF BARRELS PER DAY)  
Source: EIA  
\*Includes small volumes of medium sweet



69 per cent, of PADD III’s nine million b/d feedstock demand (Figure 3.3). In contrast, U.S. domestic supplies accounted for only 28 per cent of regional demand in 2010.

Even though light sweet crude oil imports have now been largely displaced by domestic production as result of the U.S. shale boom, significant demand for heavy oil supplies still remains. The U.S. Gulf Coast refinery complex has around two million b/d of heavy crude oil refining capacity.

While Venezuela and Mexico have traditionally been the dominant sources of heavy crude oil to the region, supplying 489,000 b/d (Venezuela) and 592,000 b/d (Mexico) in 2018, Canada has an opportunity to expand its share of this market. Today Canada is in third place, having supplied 483,000 b/d of heavy crude in 2018, but sharp declines in crude oil production in both Venezuela and Mexico mean refineries in PADD III are seeking other sources of feedstock supply. In November 2018, Mexican crude oil production was 1.86 million b/d, a decline of 22 per cent from production of 2.30 million b/d in January 2015. Production declines have been even more dramatic in Venezuela, with November 2018 production of 1.32 million b/d representing a decline of 47 per cent from 2.50 million b/d in January 2015.

Until the Keystone XL pipeline is available, the ability to replace supplies from Venezuela and Mexico will be challenging for Canadian producers. This is because Canadian producers must rely increasingly on rail, which incurs higher transportation costs and potentially requires crude oil to be sold at a substantial discount in order to capture market share.

3.3 International

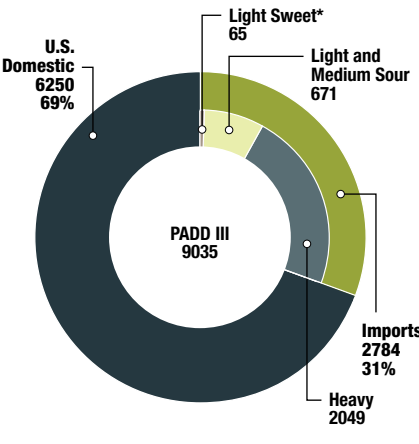
World demand for crude oil is expected to grow in the coming decades and Canada’s ability to provide additional supplies to meet this higher demand will depend on its ability to build the required market access infrastructure. According to the International Energy Agency’s World Energy Outlook 2018 (New Policies Scenario), global oil demand is projected to increase 12 per cent from 94.8 million b/d to 106.3 million b/d by 2040. Overall, energy demand will decrease in mature economies, but this will be more than offset by increases that reflect developing economies catching up with mature economies. Per capita energy consumption in developing economies is expected to increase rapidly toward OECD levels as prosperity rises. The combined demand growth from China and India of 8.2 million b/d is equal to 70 per cent of the projected world demand increase from 2017 to 2040 (Table 3.3).

Table 3.3 Total Oil Demand in Major Asian Countries  
Source: IEA World Energy Outlook 2018, New Policies Scenario

Million b/d	2017	2025	2030	2035	2040	2017 - 2040 Growth
China	12.3	14.9	15.7	15.7	15.8	3.5
India	4.4	6.2	7.4	8.4	9.1	4.7
Japan	3.6	3.1	2.7	2.4	2.1	-1.5
Southeast Asia	4.7	6	6.4	6.7	6.8	2.1
World	94.8	102.4	104.3	104.9	106.3	11.5

\*Totals may not add up due to rounding

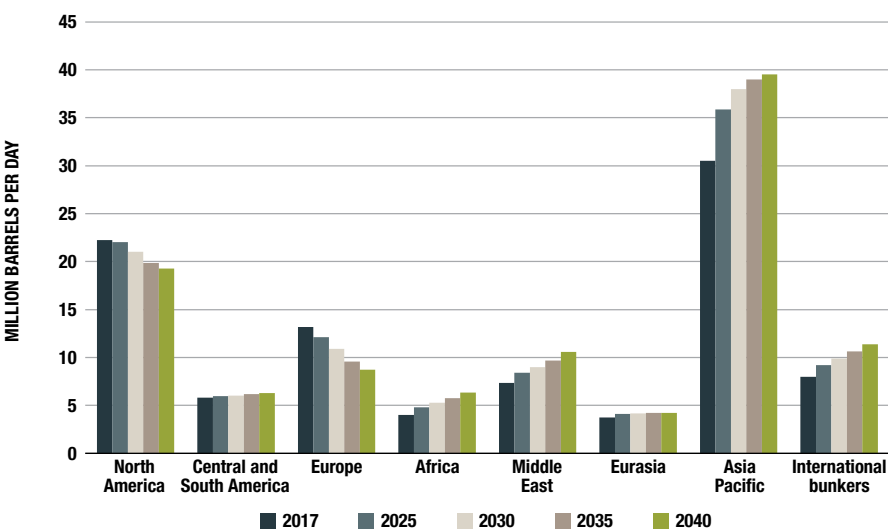
Figure 3.3 PADD III  
CRUDE OIL REFINING CAPACITY = 9754  
(THOUSANDS OF BARRELS PER DAY)  
Source: EIA  
\*Includes small volumes of medium sweet



Global oil demand is projected to increase 12 per cent by 2040.



**Figure 3.4 International Oil Demand**  
Source: International Energy Agency's World Energy Outlook, 2018



### 3.3.1 IMO Impact

Upcoming changes to United Nations International Maritime Organization (IMO) regulations may have implications for the future demand of heavy, high-sulphur crude oils produced in Alberta's oil sands. The IMO has established new requirements for bunker fuel specifications that require sulphur emissions to fall from 3.5 per cent to 0.5 per cent by 2020. Global average bunker fuel sulphur content is currently about 2.45 per cent. In total, more than three million b/d of high sulphur fuel oil (HSFO) bunkers will need to switch to 0.5 per cent sulphur fuel through blending.

The IMO standards create an uncertain outlook for the broader global refining sector, especially regarding how refiners will respond to a more sulphur-constrained global bunker fuels market. Sweet/sour differentials and light/heavy differentials will likely widen during the initial years following the change in regulation, as there will be a higher premium on sweet crudes over those heavy sour crudes that yield relatively more volumes of heavy residual fuel oil (which is used as a bunker fuel) during the refining process. The magnitude and duration of this impact is highly uncertain and depends on some key variables such as compliance and scrubber (exhaust gas cleaning systems) uptake in the maritime industry, and blending opportunities available to refiners.

### 3.4 Market Summary

While there is significant incremental market potential for Canadian producers in both the U.S. and the Asia-Pacific region, uncertainty around the timing of any additional pipeline capacity continues to frustrate producers in pursuit of these new opportunities.

Looking to the future, the bulk of Western Canada's growing heavy crude oil supplies are ideally suited for the U.S. Gulf Coast market due to the size of that region's heavy oil processing capacity and uncertainty around existing suppliers to the region. As well, pipeline projects out of Western Canada would provide producers with much-needed market optionality and reduce reliance on a single export market. This is especially important given the fact that the global markets exhibiting the greatest potential for growth in crude oil consumption lie beyond the U.S. and are found in Asia.



Uncertainty around the timing of any additional pipeline capacity continues to frustrate producers in pursuit of new opportunities.



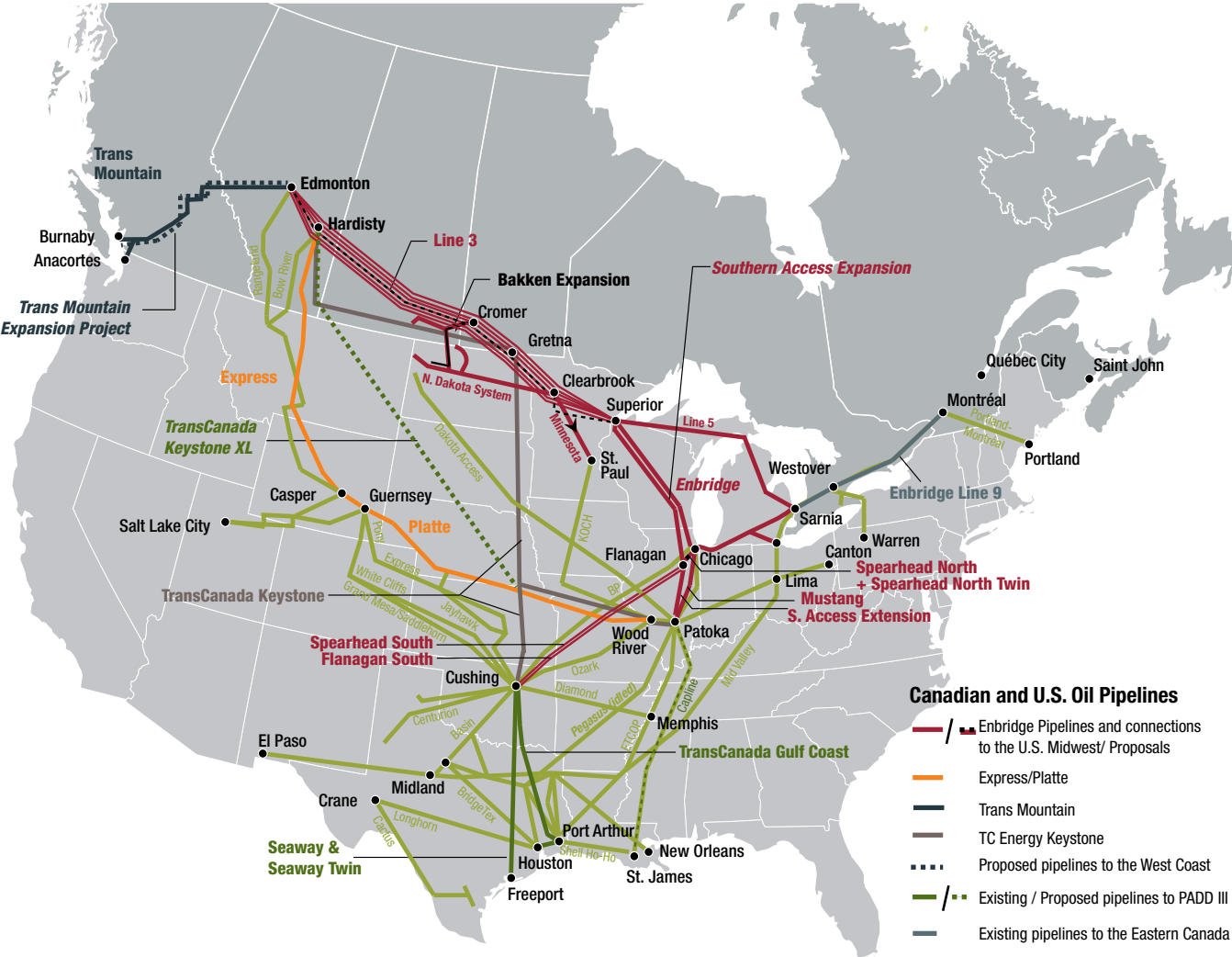


TRANSPORTATION

A well-established network of pipelines connects western Canadian crude oil producers to the North American refinery market. As early as 1950 the Interprovincial Pipeline Company (now Enbridge) began shipping western Canadian crude oil to the U.S. This pipeline network was expanded as production of crude oil from Western Canada has grown and the demand from both Canadian and U.S. refineries has increased. Yet in recent years, regulatory timelines for pipeline development have become prolonged and the pipeline network no longer keeps pace with the demands of the market, resulting in producers facing substantial pipeline capacity constraints.

The existing pipeline infrastructure network shown in Figure 4.1 is able to transport crude oil produced in Western Canada to Canadian markets as far east as Montréal, and to the West Coast. There is also the ability to transport these crude oil supplies to the U.S. Gulf Coast through interconnections with pipelines in the U.S. Midwest. As this existing network is now operating at full capacity and the timing of new pipeline capacity remains uncertain, producers are increasingly relying on rail transportation to deliver incremental production to market.

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



The price producers obtain for crude oil in any region is a function of the type of crude oil being produced and the transportation costs incurred for delivery from the production area. Pipelines are the preferred mode of shipping large volumes of crude oil long distances over land given the economics of scale. The associated costs of using rail is higher than pipelines or tankers over the same distance.

4.1 Crude Oil Pipelines Exiting Western Canada

At present, there is not enough crude oil capacity originating in Western Canada to meet the needs of producers. Both the Enbridge Mainline and Trans Mountain pipelines continue to operate under apportionment. This occurs when shipper nominations exceed the pipeline’s capacity, so pipeline operators are forced to decrease shippers’ nominated volumes on a pro-rata basis.

The combined nameplate capacity of major takeaway pipelines is more than four million b/d of crude oil from Western Canada. However, in 2018 about 635,000 b/d of capacity was unavailable as a result of equipment being offline, constraints on downstream pipelines, capacity being allocated for transporting refined petroleum products, and U.S. Bakken crude oil production taking up space otherwise available for western Canadian production (Table 4.1).

In 2018, most of the 4.66 million b/d of western Canadian crude oil supplies were transported to markets by pipeline but excess volumes depended on rail.

Refineries in Alberta and Saskatchewan that require delivery from a short distance may receive volumes from regional pipelines or trucks.



**\*Notes for estimating available capacity for Canadian crude oil to exit Western Canada on the major pipelines:**  
Enbridge Mainline = design capacity x 95% for operational downtime and downstream constraints minus estimated RPP capacity as well as estimates for U.S. Bakken moved on this system. 2018 throughput source: NEB  
Trans Mountain = design capacity minus estimate of RPP moved = 300-30 = 270  
Express = design capacity x 89% (adjusted for crude type moved, historical operational downtime, and downstream constraints) 2018 throughput source: Express Pipeline LLC FERC Form 6  
Keystone = design capacity x 95% (adjusted for crude type moved and historical operational constraints).

Table 4.1 Major Existing Crude Oil Pipelines Exiting Western Canada

Source: NEB

Pipeline	In Service	Outside Diameter Size (inches)	Distance (km)	Average Annual Capacity (000 b/d)	2018 Annual Throughput (000 b/d)	Est. Capacity Available for Crude Oil Exiting WCSB (000 b/d)
Enbridge Mainline	Operating since 1950	Various	Various	2,851	2,629	2,307
Trans Mountain	Operating since 1953	24 36 30	1,147 827 150	300	290	270
Enbridge Express	Operating since 1997	24	1,265	280	249	250
TC Energy Keystone			4,700	591	589	561
Phase 1	Operating since 2010	36	864			
Phase 2	Operating since 2011	30	2,592			
		36	468			
Gulf Coast Extension	Operating since 2014	36	700			
Houston Lateral	Operating since 2016	36	76			
TOTAL				4,022	3,757	3,388



Only three major pipeline projects remain under active development following the cancellation of the Energy East pipeline in October 2017 and Northern Gateway in November 2016. The combined capacity of Enbridge's Line 3 Replacement project, the Trans Mountain Expansion Project, and TC Energy's Keystone XL (Table 4.2) equals 1.79 million b/d. All of this capacity will be needed to meet the 1.68 million b/d of anticipated supply growth from Western Canada.

Table 4.2 Proposed Crude Oil Pipelines Exiting Western Canada

Pipeline	Outside diameter (inches)	Distance (km)	Target In service	Capacity (000 b/d)
Enbridge Line 3 Replacement	36	1,659	2020	370
Trans Mountain Expansion	36 30 24	987 (new) 3.6 x 2 (new) 193 (reactivated)	2020+	590
TC Energy Keystone XL	36	1,897	2020+	830
Total Proposed Additional Capacity				1,790

4.2 Proposed Pipeline Systems

The next sections summarize the three proposed pipelines.

4.2.1 Line 3 Replacement Program

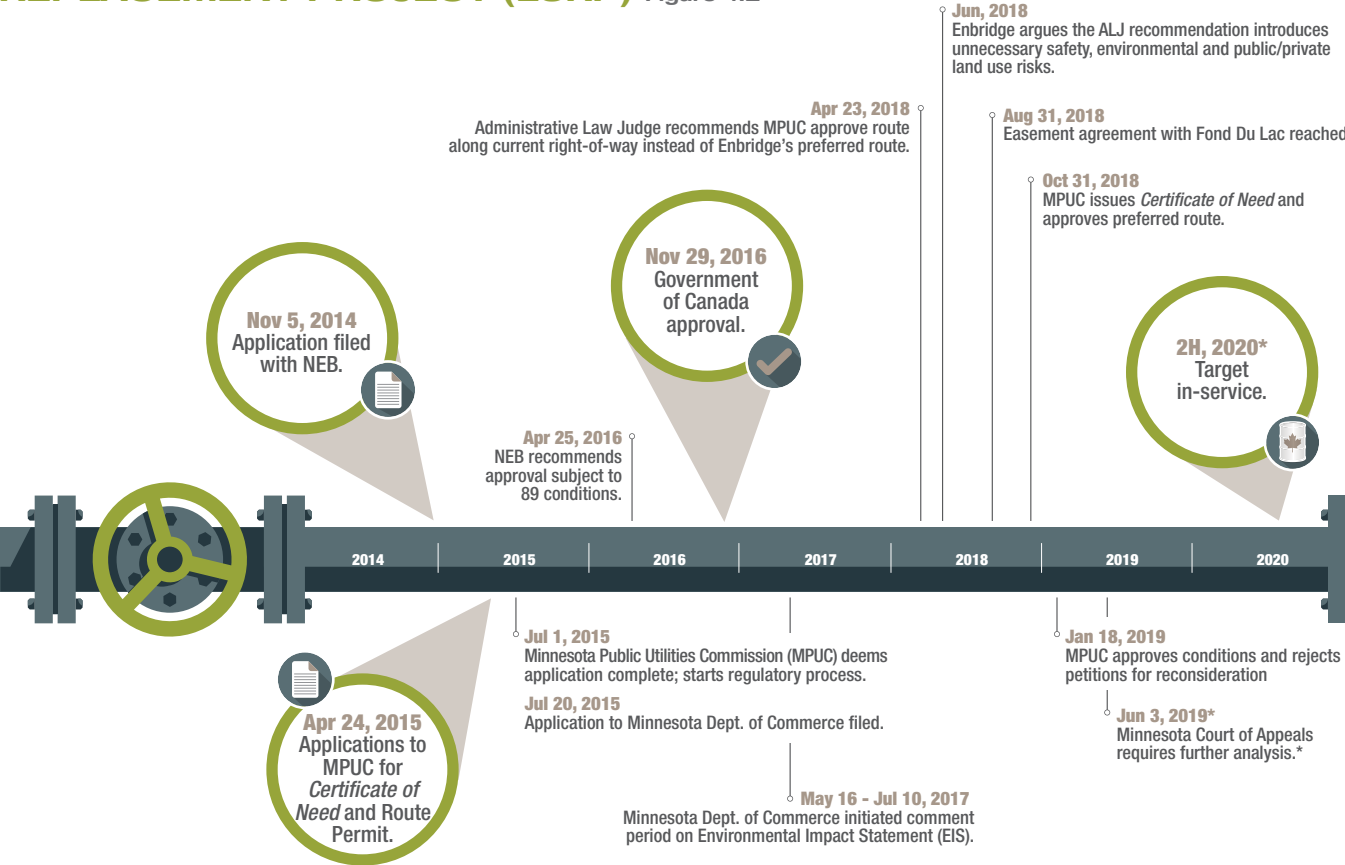
Line 3 is one of the Enbridge Mainline's primary pipelines. The original capacity of the line was 760,000 b/d but due to age and safety issues, since 2008 it has operated under voluntary pressure restrictions that have reduced its capacity to 390,000 b/d, and now requires extensive maintenance to operate even at this reduced level. The proposed Line 3 Replacement Program would replace the pipeline and restore it to its original capacity. This pipeline will be essential to ensure continued service required by refiners in Minnesota and neighbouring states, as well as Eastern Canada and the U.S. Gulf Coast.

The line was expected to be in service by the end of 2019 but with a delay in permits from the State of Minnesota the line will not be ready until the second half of 2020.

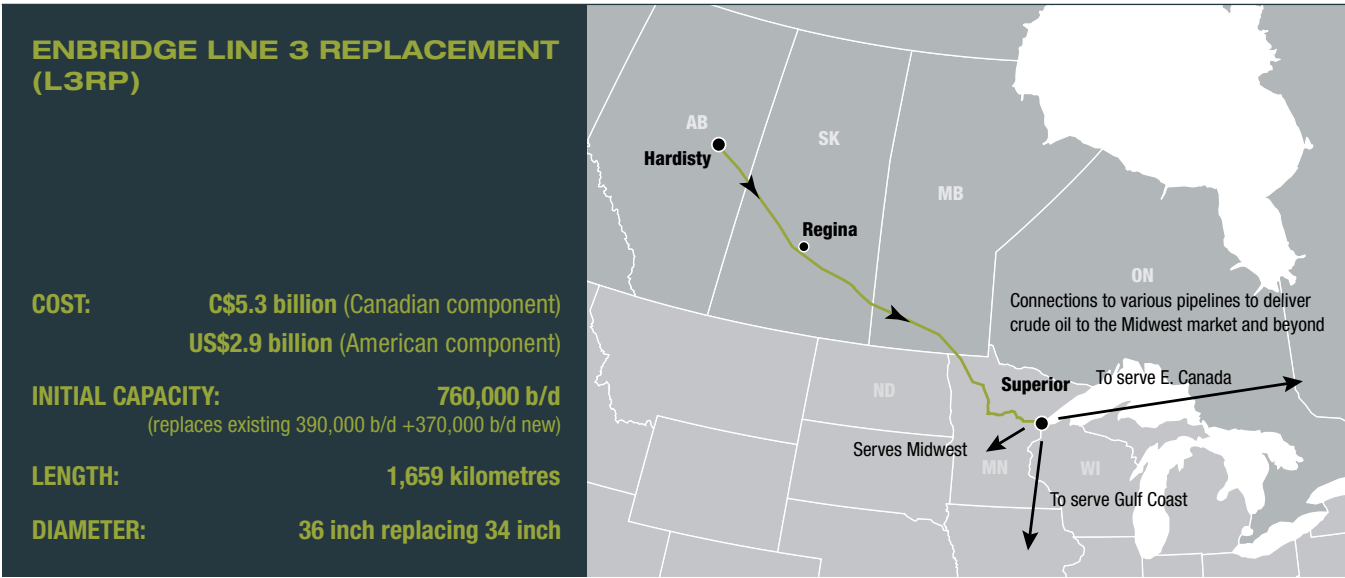
On June 3 2019 the Minnesota Court of Appeals ordered further proceedings to consider the potential impact of an oil spill into the Lake Superior watershed.



ENBRIDGE LINE 3 REPLACEMENT PROJECT (L3RP) Figure 4.2



Successful completion of L3RP will put an additional **370,000** b/d of Canadian oil on the global market.





4.2.2 Trans Mountain Expansion Project

The Government of Canada issued an Order-in-Council to approve the Trans Mountain Expansion Project (TMEP) in November 2016. Prior to that, in May 2016, the NEB determined the project was in the Canadian public interest and recommended approval of the expansion. In January 2017 the B.C. Environmental Assessment Office issued an environmental assessment certificate for the project.

The expansion essentially involves twinning the existing pipeline between Edmonton, Alberta and Burnaby, B.C. and will increase capacity from 300,000 b/d to 890,000 b/d.

In August 2018 the Federal Court of Appeal issued a decision to cancel the Order-in-Council, which had approved the Certificate of Public Convenience and Necessity for the expansion project. The NEB held public hearings to reconsider project-related environmental effects of marine shipping and further engagement with Indigenous groups. In February 2019 the NEB delivered its reconsideration report to the Government of Canada; the NEB again recommended approval of the project finding it to be in the Canadian public interest. The project is subject to 156 conditions enforceable by the NEB.

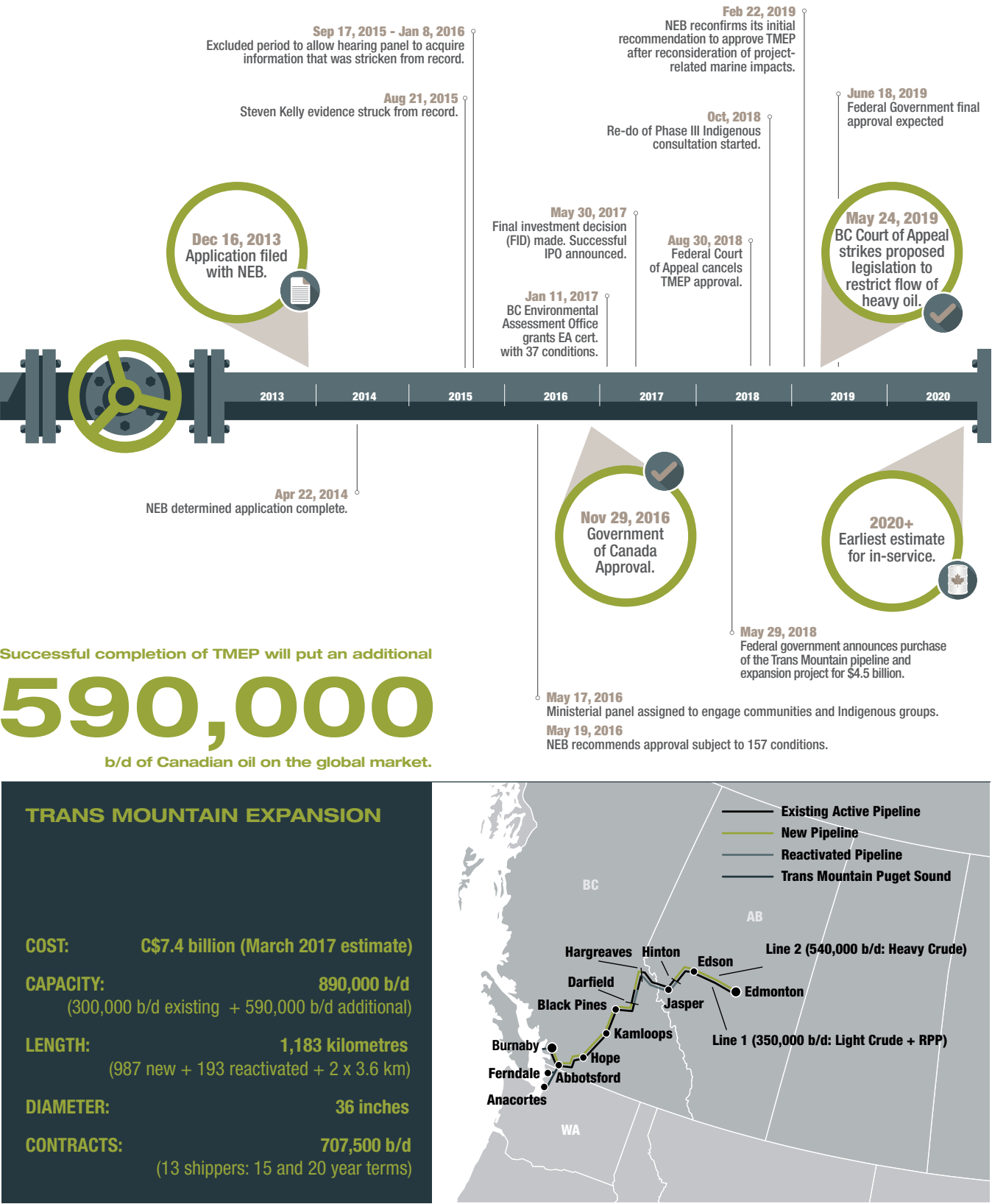
In April 2019, the Government of Canada announced that a decision on TMEP will be made June 18, 2019. CAPP expects a positive decision that will have enormous positive impacts on the Canadian economy by helping to alleviate market access constraints, resulting in increased producer and investor confidence, increased business investment and Canadian jobs, and an increase in exports. Construction beginning in the summer of 2019 should have the expansion in service by late 2022. Delays in the construction of TMEP cost Canadians \$693 million every year.<sup>8</sup>

With improved market access, the Alberta government expects an incremental \$10 billion in oil sands investment is possible in the short term, leading to incremental production of 190,000 barrels per day of bitumen. This would increase the size of Alberta’s economy alone by 1.5 to two per cent by 2023.<sup>9</sup> That investment in oil sand facilities would also create and sustain an average of 12,300 direct, indirect, and induced jobs across Canada through 2023 in addition to jobs associated with pipeline construction.<sup>10</sup>



Delays in the construction of TMEP cost Canadians \$693 million every year.<sup>8</sup>

TRANS MOUNTAIN (TMEP) EXPANSION PROJECT Figure 4.3





4.2.3 Keystone XL

The proposed 830,000 b/d TC Energy Keystone XL (KXL) pipeline will run from Hardisty, Alberta to Steele City, Nebraska. It can then connect to the existing Keystone system to transport Canadian crude to refineries on the U.S. Gulf Coast. The pipeline route passes through three U.S. states: Montana, South Dakota and Nebraska.

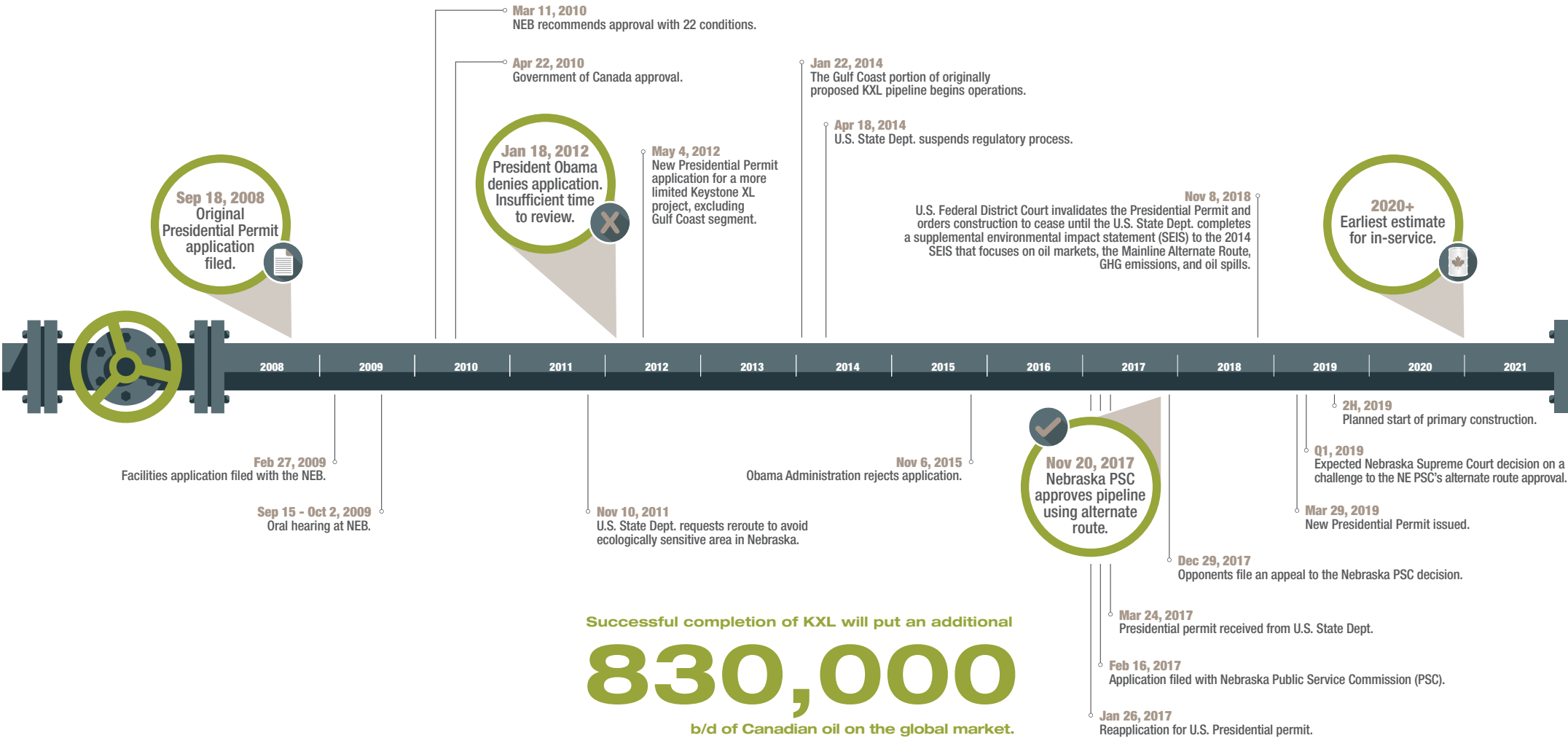
In November 2018, a federal district court in Montana ordered that TC Energy cease construction on the KXL project until the U.S. State Department completed a further environmental review. However, in March 2019 a new Presidential Permit was issued, which could render the Montana proceedings moot as this new permit does not reference or directly tie to any environmental review.

TC Energy has the primary state permits needed from South Dakota but is still awaiting some water use permits from the South Dakota Department of Environment and Natural Resources.

The Nebraska Supreme Court is expected to rule later in 2019 on KXL's proposed alternative route through the state.



TC ENERGY  
KEYSTONE XL (KXL) Figure 4.4



TC ENERGY KEYSTONE XL

COST:	C\$10.85 billion (2014 estimate)
CAPACITY:	890,000 b/d (700,000 b/d initial + 830,000 b/d additional)
LENGTH:	526 kilometres (987 new + 193 reactivated + 2 x 3.6 km)
DIAMETER:	36 inches
CONTRACTS:	500,000 b/d*

\* TC Energy announced in January 2018 that 500,000 b/d of firm 20-year commitments have been secured, including 50,000 b/d from the Govt. of Alberta. TC will continue to secure long-term contracts.

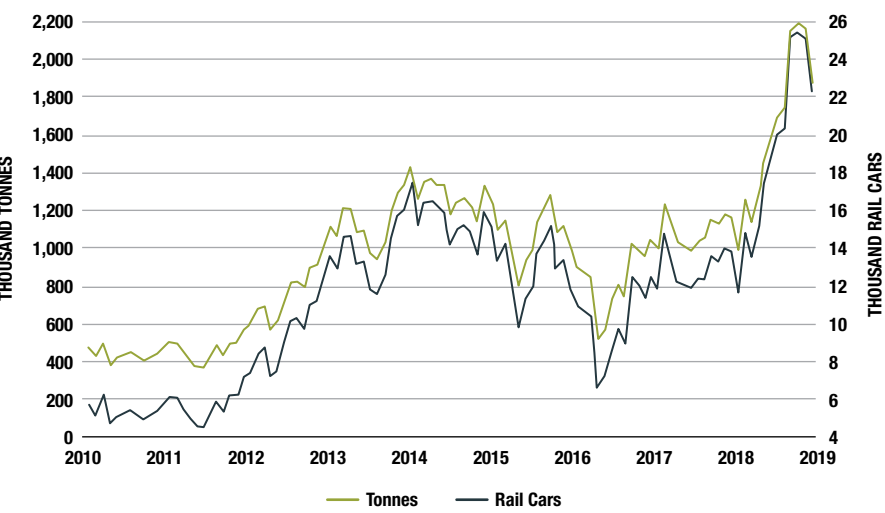




4.3 Crude by Rail

Rail transport of crude oil is expected to increase as railways add capacity, but ramping up rail capacity is not a comprehensive solution. Rail offers an alternative mode of transportation that industry will increasingly rely upon to transport crude oil as new pipeline projects continue to face challenges and delays. Industry data shows that approximately 233,000 b/d was transported to market by rail in 2018. The highest reported average volume moved in a month in 2018 was 354,000 b/d, compared to 156,000 b/d in 2017. The greatest number of rail cars moving crude in 2018 was 25,404 in November, compared to a previous historical peak of 17,371 in January 2014 (Figure 4.5).

Figure 4.5 Canadian Fuel Oil and Crude Petroleum Moved by Rail  
Source: Statistics Canada, Table 23-10-0210-01



In 2014, Transport Canada, with the U.S. Department of Transportation Pipeline and Hazardous Material Safety Administration, announced new rail tank car requirements including puncture resistance and thicker walls. Retrofits of existing tank cars must be completed by 2020, and all newly built cars must meet even more stringent standards. As a result, both retrofitted and new tank cars are in short supply. While CAPP supports stringent safety standards for tank cars, the switch to cars that meet the safety standards will take time, further enforcing the need for pipelines.

The rail-loading capacity originating in Western Canada is 1.1 million b/d. However, the current ability to move significant increased volumes of crude oil by rail is limited and cannot accommodate sudden increases in demand caused by pipeline maintenance or circumstances affecting pipeline operations. Some capacity that was available to oil producers in 2014 has since been lost to shippers of other commodities that have made long-term commitments. In order to significantly increase rail capacity, rail companies will need time to invest in additional tank cars and locomotives, and hire or train qualified staff. The Alberta Crude Oil Curtailment Program has had a dampening effect on rail export volumes.



Table 4.3 Rail Uploading Terminals in Western Canada

Operator	Location	Capacity* (b/d)	Scheduled Start up
<b>Alberta</b>			
Kinder Morgan/Imperial	Sherwood Park	712,500	Operating since April 2015
Gibson/ USD Group	Hardisty	210,000	Operating since Jul 2014
Cenovus	Bruderheim	225,000	Expansion operating since Sept 2014
Keyera/ Kinder Morgan	Edmonton	100,000	Operating since April 2015
Altex	Edmonton	40,000	Operating since Sept 2014
Savage	Lynton	27,000	Operating
Keyera/ Enbridge	Reno	25,000	Operating since Q2 2014
Gibson	Cheecham	24,000	Operating since Oct 2013
Secure/Predator	Edmonton	42,500	Operating since Q3 2015
	High Prairie	19,000	Operating since Q3 2015
<b>Saskatchewan</b>			
Plains	Kerrobert	335,500	
		70,000	Startup Nov 2015 but suspended since May 2016 as facilities were underutilized. Re-started in 2018.
Altex	Lashburn	88,000	Expanded capacity op. since 2015
Crescent Point	Stoughton	-45,000	Suspended facility account to Gov't of SK
TORQ Transloading	Unity	79,000	Operating since Mar 2012
Altex	Unity	29,000	Operating since Jul 2012
TORQ Transloading	Lloydminster	24,200	Operating since March 2012
TORQ Transloading	Bromhead	45,300	Operating since Jul 2013
<b>Manitoba</b>			
Tundra	Cromer	60,000	Expansion operating since Q4 2014
Total (b/d)		1,108,000	

Note: Facilities with less than 15,000 b/d are not shown. \*Estimated capacities based on assumptions for operating hours, available car spots, type of crude oil transported, and contracts in place (if known).

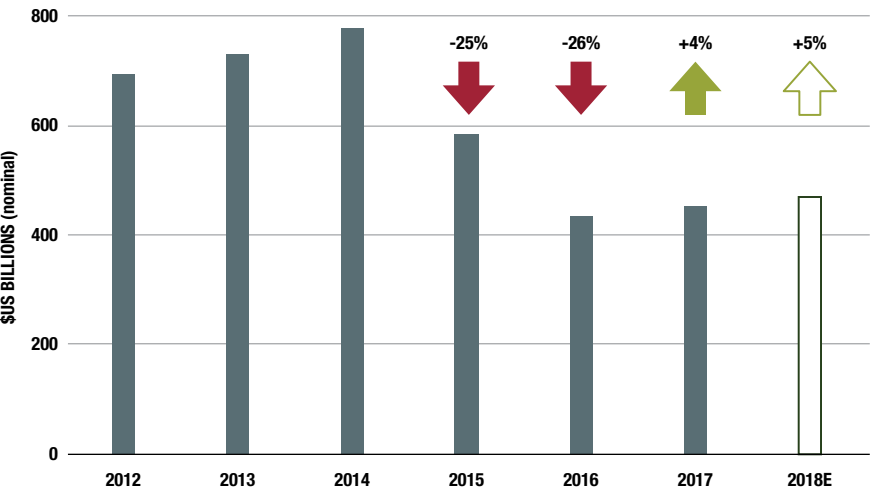
4.4 Industry Growth Outside of Canada

Global investment in 2018 increased, particularly in Egypt, the U.S. Gulf of Mexico, Guyana and Brazil. In sharp contrast, Canadian oil sands investment is down over 60 per cent from 2014 levels.

Outside of Canada, the crude oil industry has been recovering from the oil price crash of mid-2014 and numerous countries have sanctioned significant projects. Other oil producing regions have recognized that developing market access in a timely fashion is imperative if the full potential of crude oil production is to be realized. For example, Saudi Arabia producers have moved projects worth some US\$65 billion from final investment decision to fully sanctioned status. During the same time frame, the U.S. sanctioned projects worth US\$31.3 billion, Kazakhstan US\$34 billion, and Iraq US\$33.7 billion.<sup>11</sup> Unlike Canada, where producers adhere to some of the world’s highest environmental regulations, many of these countries have little to no environmental regulations. The top three countries by spending for projects awaiting final investment decision are Brazil, Kazakhstan, and Russia, totaling more than US\$214 billion;<sup>12</sup> none of these countries follow the strict environmental standards Canadian producers do.

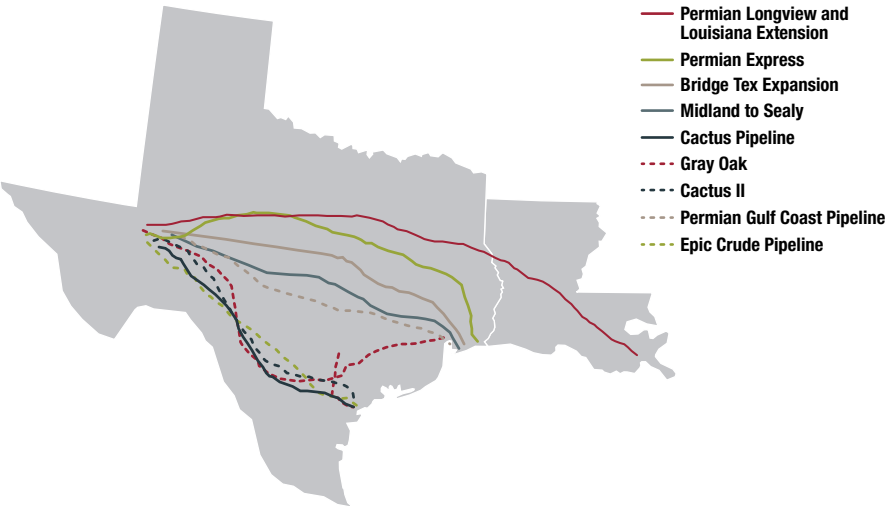


Figure 4.6 Global Investment in Upstream Crude Oil and Natural Gas  
Source: IEA



Globally, the industry is projected to increase capital spending, reaching more than US\$500 billion by the early 2020s.<sup>13</sup> Much of this increase is expected to be driven by investment in the lower 48 states of the U.S. as operators continue to exceed typical historical experience. The International Energy Agency (IEA) estimates in its World Energy Investment Report 2018 that global upstream investment in oil and gas was set to rise by five per cent to US\$472 billion (in nominal terms) in 2018, after increasing by four per cent in 2017 (see Figure 4.6). Growth was driven by U.S. capital spending in the sector increasing by about 10 per cent in 2018. The IEA highlights that oil companies have tripled their investments in shale and tight oil plays in the last two years. The Canadian experience is in marked contrast as numerous large oil companies have exited Canada after continual pipeline delays and increasingly inefficient and duplicative regulations, taking investment with them and moving jobs to the U.S.

Figure 4.7 Recently Constructed and Under Construction Permian Basin Pipelines



Numerous large oil companies have exited Canada after continual pipeline delays and increasingly inefficient and duplicative regulations.



Table 4.4 Recently Constructed and Under Construction Crude Oil Pipelines Exiting the Permian Basin

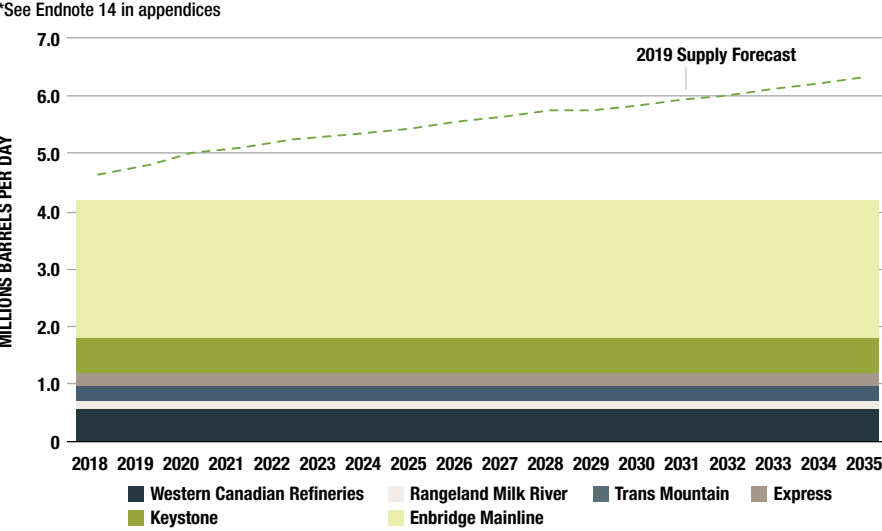
Pipeline	Owner	Capacity	Status
Permian Longview & Louisiana Extension	Sunoco	100,000 bpd	Operational since 2016
Permian Express II	Sunoco	200,000 bpd	Operational since 2015
Bridge Tex Expansion	Magellan Midstream	400,000 bpd	Operational; expansion since 2017
Midland to Sealy	Enterprise Product Partners	575,000 bpd	Operational since 2018
Cactus Pipeline	Plains All American	300,000 bpd	Operational since 2015
Gray Oak	Philipps 66	800,000 bpd	Under Construction; in-service 4Q19
Cactus II	Plains All American	670,000 bpd	Under Construction; in-service 3Q19
Epic Crude Pipeline	Epic Midstream Holdings	900,000 bpd	Under Construction; in-service 4Q19
TOTAL		3,945,000 bpd	

The U.S. administration has aggressively streamlined regulations and re-adjusted tax rates. In sharp contrast to the experience in Western Canada, the growth in production in the U.S. has been facilitated by a significant increase in pipeline capacity with a number of pipeline projects recently completed and several more projects currently under construction to move crude oil to Gulf Coast refineries. In recent years the production of crude oil in the Permian basin has increased from less than one million b/d in 2010 to more than 4.1 million b/d in 2019 (Table 4.4 and Figure 4.7). In addition to pipelines currently under construction, a number of other proposals are in early stages of development.

Canada has an opportunity to displace less sustainable oil; however, the current regulatory environment and policies are inefficient and duplicative, and are combining to create unintended consequences such as driving investment away from Canada into other countries that have less robust emissions reduction policies. A strong tradition of innovation and collaboration can position responsibly produced Canadian oil to meet global energy demand.

4.5 Transportation Summary

Figure 4.8 Existing Takeaway Capacity from Western Canada vs. Supply



Existing pipeline infrastructure to transport crude oil production is at capacity and it is uncertain when additional pipeline capacity will become available. Rail is struggling to meet the increased demand from oil producers. This in turn limits Canada’s ability to serve existing domestic and U.S. markets, and prevents Canada from accessing emerging overseas markets. Even more urgently, lack of infrastructure has caused discounted prices for Canadian crude oil exports to the U.S. The lack of market access is leading firms to curtail their investment, and limiting Canada’s potential economic growth. The anticipated Trans Mountain decision in June 2019 has the potential to alleviate some of the market access constraints the industry faces and allow Canadians to receive the best value for resources.

Global demand for oil, including heavy oil such as WCS, is growing – especially in India, China and Southeast Asia. Canadian producers have an opportunity to export oil to emerging global markets but there is not enough pipeline capacity to allow producers to capitalize on this growing demand. By 2035, the supply of crude oil is expected to increase by 1.7 million b/d and even this constrained outlook of supply growth is contingent on Canada significantly increasing its egress capacity from the WCSB.



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.
Condensate	A mixture of mainly pentanes and heavier hydrocarbons. U.S. condensate is 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 NGLs, natural gasoline, pentanes plus or C5+, that remain 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 U.S. 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 its source (oil sands).
Feedstock	In this report, feedstock refers to the raw material supplied to a refinery or oil sands upgrader.

Integrated mining project	A combined mining and upgrading operation where oil sands are mined from open pits. The bitumen is then separated from the sand and upgraded by a refining process.
In situ recovery	The process of recovering crude bitumen from oil sands by drilling.
Merchant upgrader	Processing facilities that are not linked to any specific extraction project but is designed to accept raw bitumen on a contract basis from producers.
Oil	Condensate, crude oil, or a constituent of raw gas, condensate, or crude oil that is recovered in processing and is liquid at the conditions under which its volume is measured or estimated.
Oil sands	Refers to a mixture of sand and other rock materials containing crude bitumen or the crude bitumen contained in those sands.
Oil sands deposit	A natural reservoir containing or appearing to contain an accumulation of oil sands separated or appearing to be separated from any other such accumulation. The 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).
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.



# APPENDICES

## Endnotes

1.

April MPR Report: The Bank expects that the level of investment in the oil and gas sector in 2019 will be about 20 per cent lower than its 2017 plateau. This contraction follows the steep decline of roughly 50 per cent that occurred between 2014 and 2016. the Bank's projections for production and exports of Canadian oil are anchored by transportation capacity rather than by an assumption about the price of Western Canadian Select.

2.

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3.

IHS Markit, Greenhouse Gas Intensity of Oil Sands Production, September 2018.

4.

BMO Capital Markets, ESG, Yeah You Know Me: Innovation and the Search for 'Friendly Oil,' based on third-party data sources (Yale Environmental Performance Index, Social Progress Imperative's Social Progress Index, World Bank Worldwide Governance Indicators Benchmark), February 2019.

5.

2018 Joint Working Group – Industry Submission to Ministers; Proposed Actions to Address the Competitiveness of Canada's Upstream Oil and Natural Gas Sector.  
<https://www.capp.ca/publications-and-statistics/presentations-and-third-party-reports>

6.

The World Population Prospects, 2017 Revision, UN Department of Economic and Social Affairs, 2017. According to the medium variant projection.

7.

Homi Kharas, The Unprecedented Expansion of the Global Middle Class, An Update, Global Economy and Development. Brookings. 2017.

8.

JWN Energy, (2019). Trudeau announces one-month delay on Trans Mountain decision. April 22, 2019.

9.

<https://open.alberta.ca/dataset/8beb5614-43ff-4c01-8d3b-f1057c24c50b/resource/68283b86-c086-4b36-a159-600bcac3bc57/download/2018-21-fiscal-plan.pdf>

10.

CAPP estimates based on Prism Economics analysis of the oil and natural gas industry's economic impacts according to Statistics Canada's Input/Output tables.

11.

Wood Mackenzie.

12.

Ibid

13.

<https://my.woodmac.com/reports/upstream-oil-and-gas-why-a-shortage-of-investment-opportunities-is-upstreams-biggest-challenge-28944?contentId=28944>

14.

Figure 4.8 Notes.  
Capacity shown can be reduced by any extraordinary and temporary operating and physical constraints.  
1. Enbridge capacity adjusted by operational downtime and capacity for RPP and U.S. Bakken crude oil.  
2. Keystone: adjustment to 99% of nameplate capacity for maintenance downtime.  
3. Express: contract capacity only due to downstream Platte pipeline constraints.  
4. Trans Mountain: RPP capacity requirements subtracted from nameplate capacity.  
5. Rangeland and Milk River: throughput estimated at 107,000 b/d, which is the maximum realized annual crude oil throughput since 2010.  
6. Western Canadian refineries: approximate refinery intake in AB (incl. Sturgeon refinery from 2018+) and SK but excludes BC (85% of 682,000 b/d).



APPENDIX A.1

CAPP Canadian Crude Oil Production Forecast 2019 - 2035  
June 2019

Thousand barrels per day										ACTUAL		FORECAST														
EASTERN CANADA	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Ontario	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Atlantic provinces (including Pentanes & Condensate) <sup>1</sup>	283	272	201	231	219	175	212	223	232	290	299	288	304	318	303	319	353	322	292	235	184	148	130	115	102	90
EASTERN CANADA	284	274	202	232	220	176	213	224	233	291	300	288	305	319	304	320	354	323	293	236	185	149	130	115	102	91
WESTERN CANADA																										
Conventional Light & Medium																										
Alberta	316	348	407	431	439	393	326	334	374	367	350	336	332	336	342	346	347	346	344	341	339	337	334	330	328	326
British Columbia	22	20	21	20	22	21	23	21	21	21	21	21	21	21	21	21	21	21	21	21	20	20	20	20	20	20
Saskatchewan <sup>2,3</sup>	186	188	211	229	248	238	226	244	251	246	238	232	237	247	256	260	263	263	262	260	259	258	256	254	253	252
Manitoba	32	41	53	51	49	46	40	39	40	39	38	38	37	37	36	36	35	34	34	33	32	32	31	30	30	29
North West Territories	15	10	13	11	11	10	9	0	0	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Western Canada Light and Medium	571	607	705	742	768	708	625	638	686	683	657	637	636	650	665	673	676	674	671	665	661	656	651	644	641	637
Heavy																										
Alberta Conventional Heavy	144	144	149	151	151	137	118	112	116	114	110	107	105	105	105	105	105	105	105	105	104	104	104	103	103	103
Saskatchewan Conventional Heavy <sup>2,3</sup>	235	242	260	257	267	248	233	241	237	236	226	217	212	214	219	221	222	222	221	219	218	216	215	213	213	212
Western Canada Conventional Heavy	380	386	409	409	417	385	351	353	353	349	336	324	317	319	324	327	328	327	326	324	322	321	319	316	316	314
WESTERN CONVENTIONAL (excl. Pentanes/Condensate)	951	994	1,114	1,151	1,186	1,093	976	991	1,038	1,032	993	960	954	969	989	999	1,003	1,001	997	989	984	977	969	961	957	951
TOTAL PENTANES/CONDENSATE <sup>4</sup>	133	133	132	147	181	220	265	326	405	427	452	474	498	516	564	594	593	597	607	610	613	619	611	594	576	560
WESTERN CANADA CONVENTIONAL (incl. Pentanes/Condensate) <sup>1</sup>	1,083	1,126	1,247	1,298	1,366	1,313	1,241	1,317	1,443	1,459	1,445	1,434	1,452	1,485	1,553	1,594	1,596	1,598	1,603	1,599	1,597	1,595	1,580	1,554	1,532	1,510
OIL SANDS (BITUMEN & UPGRADED CRUDE OIL)																										
Oil Sands Mining	727	772	811	849	912	1,023	1,028	1,137	1,354	1,455	1,511	1,545	1,575	1,626	1,631	1,626	1,659	1,680	1,713	1,708	1,718	1,725	1,813	1,832	1,820	1,819
Oil Sands In Situ	743	843	984	1,093	1,243	1,342	1,372	1,510	1,559	1,563	1,684	1,743	1,809	1,823	1,864	1,946	1,989	2,043	2,068	2,096	2,163	2,212	2,206	2,273	2,363	2,435
OIL SANDS	1,470	1,615	1,795	1,942	2,155	2,365	2,400	2,646	2,913	3,018	3,195	3,288	3,384	3,449	3,494	3,572	3,647	3,723	3,780	3,804	3,882	3,937	4,019	4,105	4,183	4,253
TOTAL WESTERN CANADA CRUDE OIL PRODUCTION	2,554	2,741	3,042	3,239	3,521	3,678	3,641	3,963	4,356	4,477	4,640	4,722	4,836	4,934	5,047	5,166	5,243	5,321	5,384	5,403	5,479	5,533	5,599	5,659	5,716	5,764
TOTAL EASTERN CANADA CRUDE OIL PRODUCTION	284	274	202	232	220	176	213	224	233	291	300	288	305	319	304	320	354	323	293	236	185	149	130	115	102	91
TOTAL CANADIAN CRUDE OIL PRODUCTION	2,838	3,015	3,244	3,472	3,742	3,853	3,854	4,187	4,589	4,768	4,940	5,011	5,141	5,253	5,351	5,486	5,597	5,644	5,676	5,638	5,664	5,681	5,730	5,774	5,818	5,855
Notes:																										
1. Atlantic Canada production includes Newfoundland & Labrador production and minor volumes from New Brunswick. Condensate/pentanes from Nova Scotia and New Brunswick are also included.																										
2. CAPP allocates Saskatchewan Area III Medium crude as heavy crude. Also 17% of Area IV is > 900 kg/m³.																										
3. CAPP has revised from June 2007 report historical light/heavy ratio for Saskatchewan starting in 2005.																										
4. Pentanes/Condensate production reported does not include pentanes that are part of the NGL stream that is shipped to Ontario. Only produced volumes that are available for diluent purposes are reported here.																										
OIL SANDS RAW BITUMEN																										
Oil Sands Mining	857	892	930	977	1,038	1,162	1,147	1,276	1,472	1,565	1,624	1,658	1,695	1,713	1,717	1,718	1,724	1,741	1,742	1,777	1,783	1,803	1,858	1,885	1,899	1,901
Oil Sands In-Situ	759	852	996	1,109	1,266	1,365	1,391	1,547	1,583	1,588	1,708	1,764	1,830	1,885	1,933	2,014	2,060	2,113	2,149	2,178	2,245	2,285	2,284	2,348	2,437	2,498
TOTAL OIL SANDS	1,616	1,745	1,926	2,085	2,305	2,527	2,538	2,823	3,055	3,153	3,332	3,422	3,524	3,598	3,650	3,732	3,784	3,854	3,892	3,955	4,028	4,088	4,142	4,233	4,336	4,399

\* Raw bitumen numbers are provided at the bottom of the table and do not reflect upgrading. the oil sands production numbers at the top of the table (as historically published) are a combination of upgraded crude oil and bitumen, therefore, incorporate yeild losses from integrated upgrader projects. Production from off-site upgrading projects are included in the production numbers as bitumen.



APPENDIX A.2

CAPP Western Canadian Crude Oil Supply Forecast 2019 - 2035  
Blended Supply to Trunk Pipelines and Markets

Thousand barrels per day

	ACTUAL									FORECAST																			
CONVENTIONAL	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035			
Light and Medium	567	603	701	738	764	704	621	634	682	679	653	633	632	646	661	669	672	670	667	661	657	652	647	640	637	633			
Net Heavy to Market	315	317	337	361	363	315	280	285	277	273	258	245	238	239	245	248	249	249	247	245	243	241	239	237	236	234			
CONVENTIONAL	882	920	1,038	1,099	1,128	1,018	901	919	959	952	911	877	870	886	906	917	921	919	914	906	901	893	886	877	873	867			
OIL SANDS																													
Upgraded Light (Synthetic) <sup>1</sup>	660	703	752	719	756	735	636	673	719	812	833	863	926	973	965	954	956	954	979	993	980	976	989	992	994	973			
Oil Sands Heavy <sup>2</sup>	1,126	1,277	1,432	1,633	1,916	2,229	2,373	2,603	2,979	3,038	3,259	3,352	3,430	3,438	3,512	3,601	3,705	3,793	3,860	3,884	3,986	4,080	4,148	4,270	4,387	4,496			
OIL SANDS AND UPGRADED BITUMEN	1,786	1,980	2,184	2,352	2,672	2,963	3,009	3,276	3,698	3,850	4,092	4,216	4,356	4,412	4,477	4,555	4,660	4,747	4,839	4,877	4,966	5,056	5,137	5,262	5,381	5,469			
Total Light Supply	1,227	1,306	1,454	1,457	1,521	1,438	1,258	1,307	1,401	1,490	1,486	1,496	1,559	1,620	1,627	1,622	1,627	1,624	1,645	1,654	1,637	1,628	1,636	1,633	1,631	1,606			
Total Heavy Supply	1,441	1,594	1,769	1,994	2,279	2,543	2,653	2,888	3,256	3,311	3,518	3,597	3,667	3,677	3,757	3,849	3,954	4,041	4,108	4,129	4,230	4,321	4,387	4,507	4,623	4,730			
WESTERN CANADA CRUDE OIL SUPPLY	2,668	2,900	3,222	3,451	3,800	3,982	3,910	4,194	4,657	4,802	5,004	5,093	5,226	5,297	5,384	5,472	5,581	5,666	5,753	5,783	5,867	5,949	6,023	6,139	6,254	6,336			

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

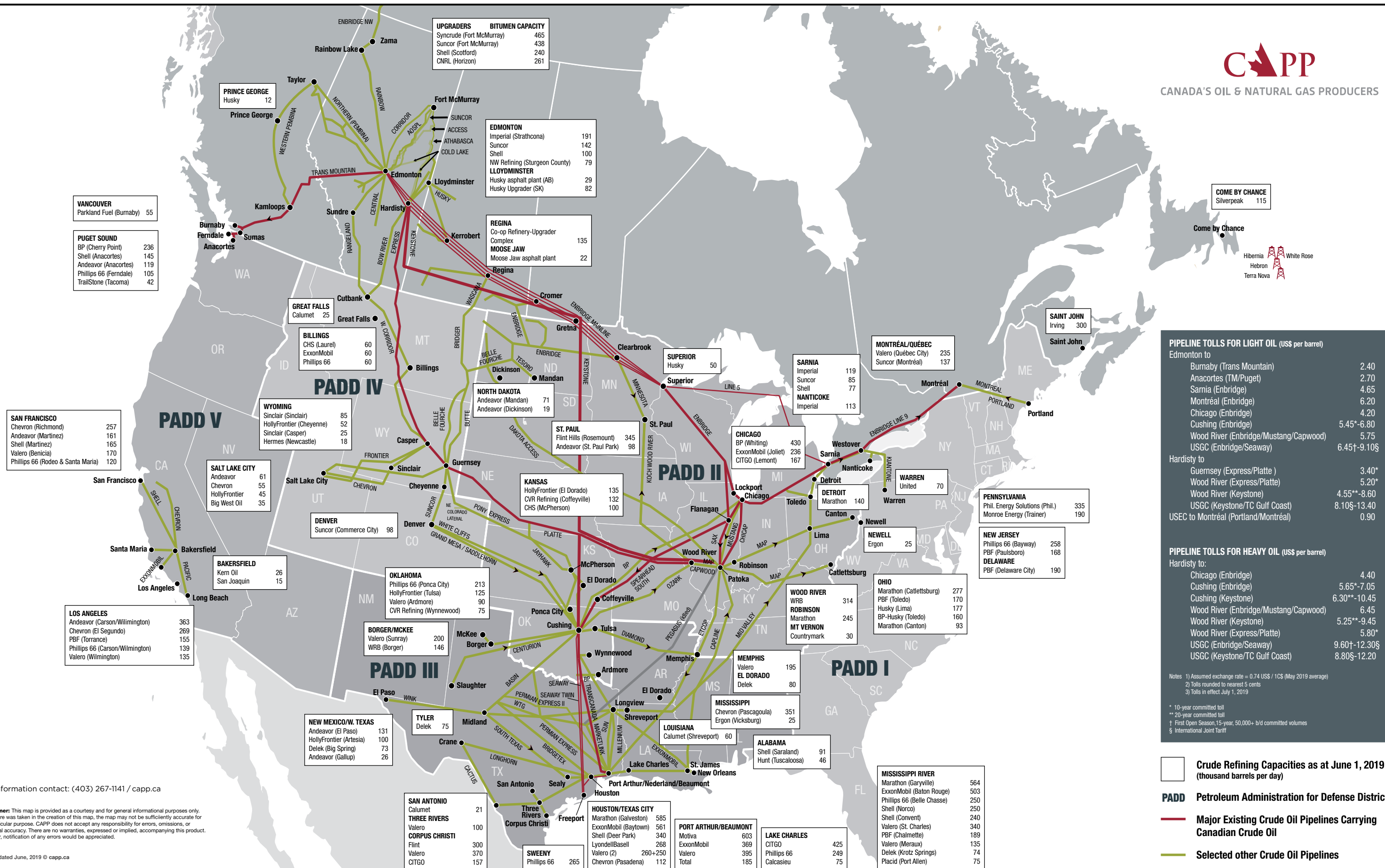
Acronyms, Abbreviations, Units and Conversion Factors

Acronyms		Canadian Provincial Abbreviations	
API	American Petroleum Institute	AB	Alberta
AER	Alberta Energy Regulator	BC	British Columbia
CAPP	Canadian Association of Petroleum Producers	MB	Manitoba
EIA	Energy Information Administration	NB	New Brunswick
FERC	Federal Energy Regulatory Commission	NL	Newfoundland and Labrador
IEA	International Energy Agency	NT	Northwest Territories
NEB	National Energy Board	ON	Ontario
PADD	Petroleum Administration for Defense District	QC	Québec
RPP	refined petroleum products	SK	Saskatchewan
U.S.	United States		
WTI	West Texas Intermediate		
Units		Conversion Factor	
b/d	barrels per day	1 cubic metre = 6.293 barrels (oil)	

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



# CANADIAN AND U.S. CRUDE OIL PIPELINES AND REFINERIES - 2019





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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 80 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 \$101 billion a year.

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CANADA'S OIL & NATURAL GAS PRODUCERS

**CAPP.CA**

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