Crude Oil

Forecast, Markets & Pipelines

June 2010

CANADIAN ASSOCIATION
OF PETROLEUM PRODUCERS

EXECUTIVE SUMMARY

The CAPP 2009 forecast exhibited a tempered rate of growth relative to prior year forecasts and was a reflection of the deferrals of many oil sands projects announced last year. This was the direct response by producer companies to the 2008-09 economic downturn and lower oil prices at the time. In contrast, the economic climate has recovered somewhat at the time of this year's forecast. In the first quarter of 2010, WTI oil prices have increased to the US $70-85 per barrel range, a range in which oil sands projects currently become economic. In response, several companies are now actively developing phases of their projects that had previously been placed on hold.

Ultimately, the goal of this report is to provide industry with a timely and objective view of the changes in crude oil supply availability over the next 15 years. It is also meant to help develop an understanding of the major trends affecting industry.

Canadian Crude Oil Production and Supply

At the beginning of each year, CAPP conducts a survey of all oil sands producers in order to form the basis of its annual long-term outlook for Canadian crude oil. This year's expected forecast is referred to as the "Growth" Case. An additional case, known as the "Operating & In Construction" Case, is shown to provide a foundation to the expected case. This latter case represents the minimum potential growth from the oil sands as these projects are already built or are in construction. The forecast under both cases is summarized in the following table.

For the first few years of the outlook period, the latest Growth Case is similar to CAPP's 2009 view. By the end of the period in 2025 the forecast shows a slightly higher supply outlook than previously forecasted due to the emergence of several new projects that were not part of last year's survey.

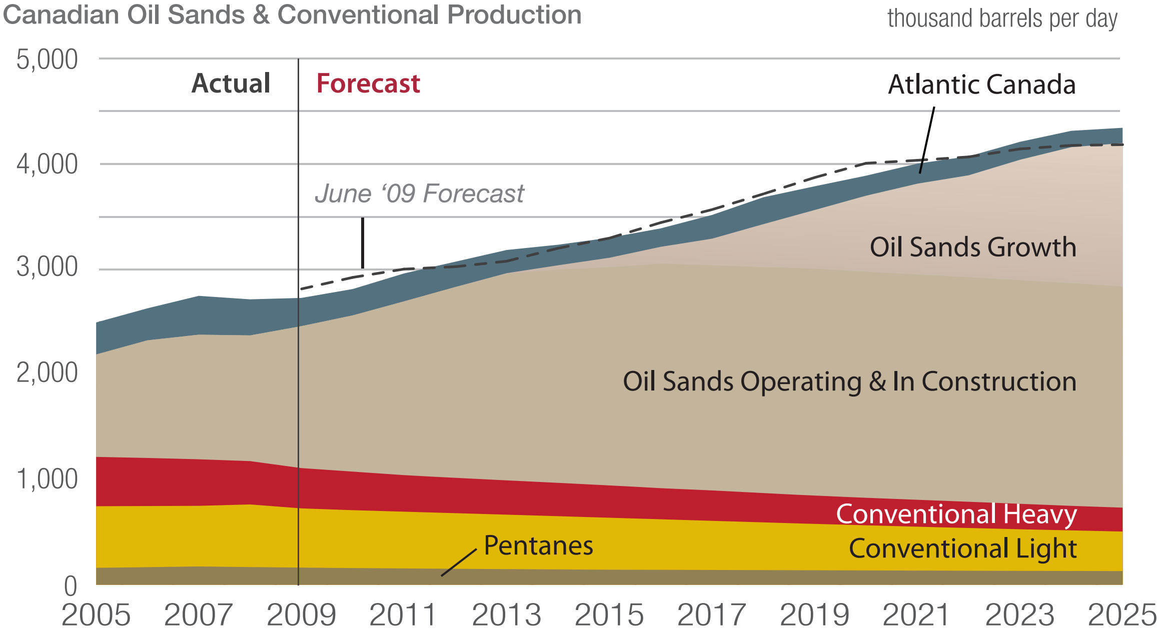
Compared to the 2009 forecast, the Upgraded Light crude oil supply portion is lower since many companies have reconsidered building upgrading faciliites and producers anticipate using more upgraded crude oil as diluent.

Canadian Crude Oil Production

million b/d	2009	2015	2020	2025
Growth	2.72	3.29	3.88	4.34
Operating & In Construction	2.72	3.20	3.16	2.98

In the Operating & In Construction Case, production is forecast at only 3.0 million b/d by 2025 due to the decline in conventional production. The rate of decline in overall conventional production that has been exhibited in recent years is expected to slow somewhat. The use of newer technology in mature fields in Saskatchewan, Alberta and Manitoba is expected to increase light crude oil production from these provinces during the next few years. Of particular note, the industry optimism over the potential increased production from the Cardium oil plays in Alberta is similar to that generated by the Bakken formation in Saskatchewan over the last couple of years.

Canadian Oil Sands & Conventional Production



Crude Oil Markets

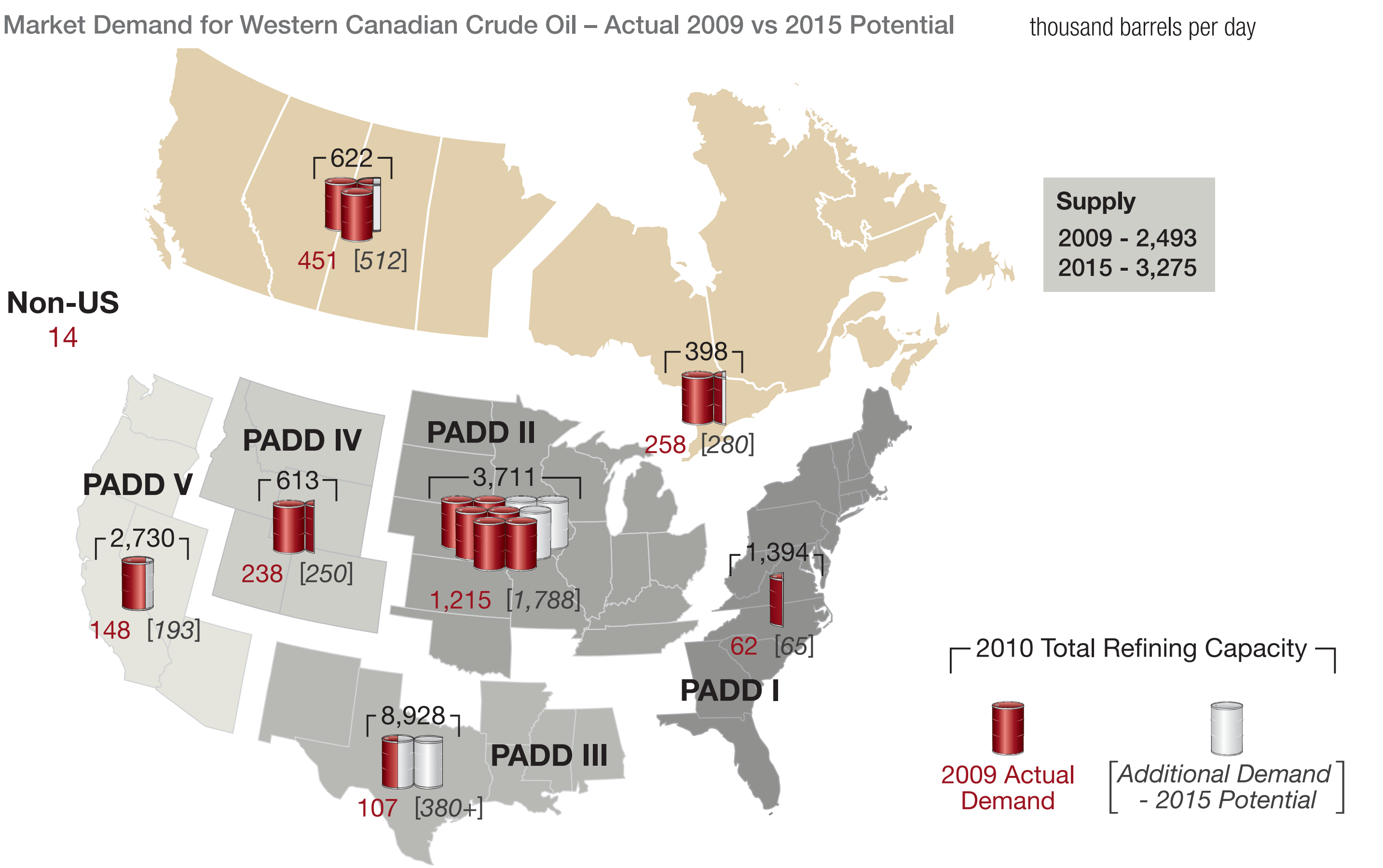
CAPP also surveyed refiners in Canada and the U.S. to determine both the current volumes of western Canadian crude oil received and any future plans to process additional supplies.

Based on the survey results, the traditional markets in the U.S. Midwest will continue to be well served by Canadian crude oil supplies. Demand in this market will continue to grow as additional heavy oil refining capacity in the region is added to take advantage of growing volumes of heavy western Canadian crude oil. However, growing volumes of Canadian heavy supply also means that new markets for these volumes must be found. The U.S. Gulf Coast is one such market. Western Canadian producers will be able to tap into more of this large market around 2013, once the Keystone XL Pipeline is in service. Growing Asian oil demand also represents a potential future market for Canadian crude oil production.

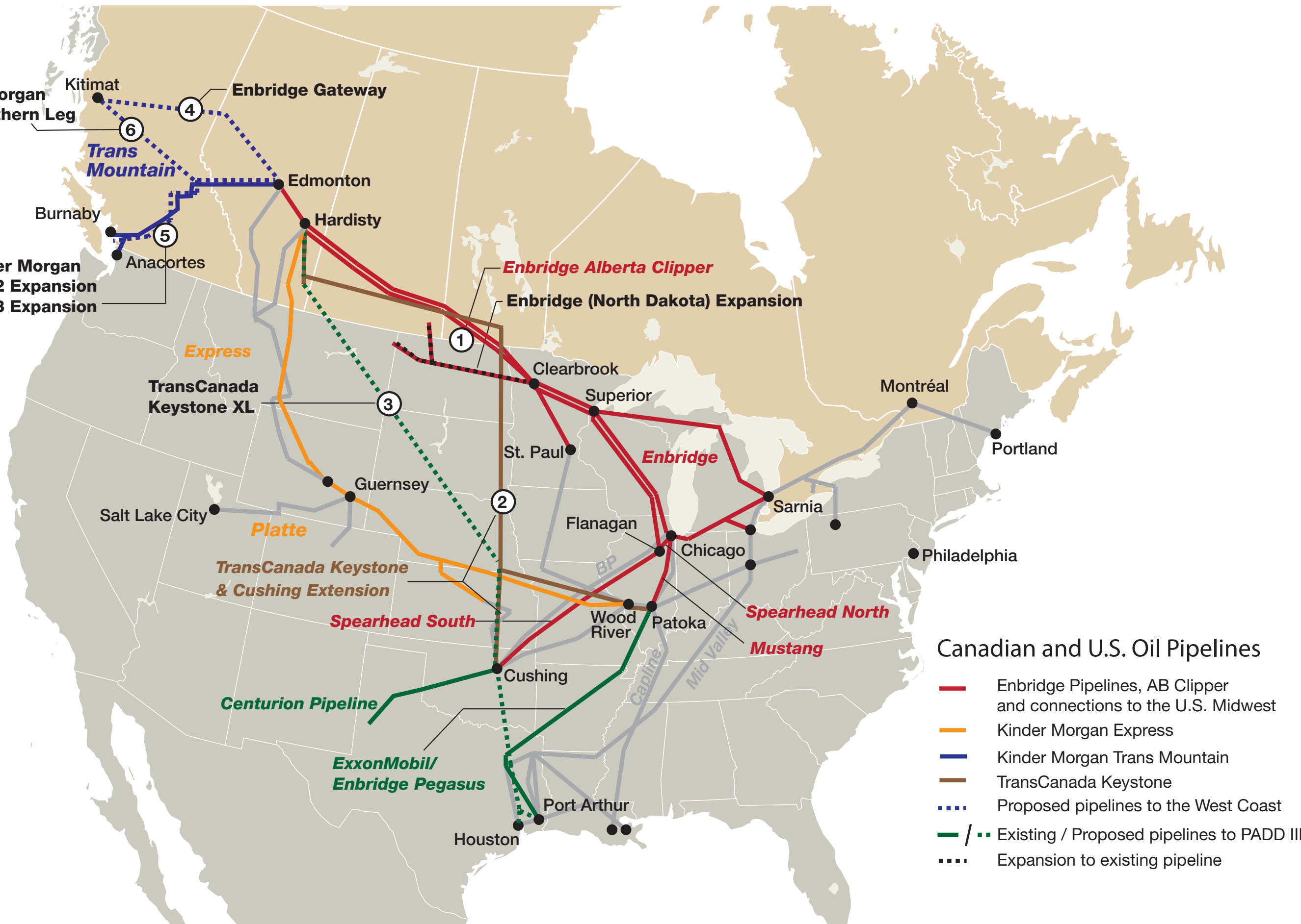
Crude Oil Pipelines and Expansions

In 2010, 885,000 b/d of new pipeline capacity exiting the Western Canada Sedimentary Basin was added and another 855,000 b/d has been approved that could go into service over the next few years. In addition, there are other projects being proposed that could add capacity. These pipeline projects will provide producers with increased access to traditional markets as well as access to the Gulf Coast and offshore West Coast markets. Such market diversity is important for producers who are investing large amounts of capital in order to grow crude oil production. The timing of the approved projects going into service, however, will mean that excess pipeline capacity out of the basin will exist until around 2022, when growth in crude oil supply is expected to reach over 4.0 million b/d.

Market Demand for Western Canadian Crude Oil – Actual 2009 vs 2015 Potential



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



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1 INTRODUCTION

Each year, CAPP develops a long-term outlook for Canadian crude oil production. Since 2007, this report has been expanded to include a market outlook and a comprehensive summary of the pipeline proposals that would allow growing volumes of Canadian crude oil to access new markets and expand deliveries to traditional markets. Ultimately, the goal of this report is to provide industry with a timely and objective view of the changes in crude oil supply availability over the next 15 years. The report is also meant to help develop an understanding of the major trends affecting industry.

The forecast incorporates the latest available information on economic and industry trends affecting crude oil production in Canada. The 2009 forecast exhibited a tempered rate of growth relative to prior year forecasts and was a reflection of the deferrals of many oil sands projects announced last year. This was the direct response by producers to the 2008-09 economic downturn and lower oil prices at the time. In contrast, the economic climate has recovered somewhat during the preparation of this latest forecast. In the first quarter of 2010, WTI oil prices increased to the US$70-85 per barrel range, a range which meets the required threshold for certain oil sands projects to be economic. In response, several companies are now actively developing phases of their projects that had previously been placed on hold.

For the initial part of the outlook period, this latest forecast is similar to CAPP's 2009 forecast. By the end of the forecast period in 2025, the forecast shows a slightly higher supply outlook than previously forecasted due to the emergence of several new projects that were not part of last year's survey. This improved outlook for the industry coincides with the new investments in oil sands projects by major Chinese companies. These investments will be a source of future production growth and are part of the reason for the slightly improved Canadian crude oil supply outlook from last year's forecast. CAPP's estimate of industry capital spending for oil sands development is $13 billion for 2010 compared to $11 billion spent in 2009.

The forecast for U.S. market demand is relatively unchanged from the 2009 report. The greatest demand for western Canadian crude oil in the U.S. is expected to come from refineries in PADD II, the traditional market for western Canadian crude oil. The completion of new pipeline capacity, however, will provide access to U.S. Gulf Coast refiners and is reflected in higher PADD III demand in the future.

The outline of the report is as follows:

- Chapter 1 provides an introduction to the report
- Chapter 2 discusses the latest crude oil production and supply forecast
- Chapter 3 summarizes the major potential crude oil markets
- Chapter 4 describes the existing major crude oil pipeline network and proposed expansions

2 | CRUDE OIL PRODUCTION AND SUPPLY FORECAST

In Canada, crude oil is primarily produced from the western provinces, the Northwest Territories and Atlantic Canada. Oil sands production first surpassed conventional production in 2006. Since then, the oil sands deposits in Alberta continue to be the main focus of future oil production growth from western Canada. Conventional production from mature oil fields continues to decline. However; in recent years, the Bakken oil formation in Saskatchewan and now the Cardium oil formation in Alberta have generated significant interest. Production from Atlantic Canada contributed approximately 10 per cent of Canadian production in 2009. The Oil and Gas Journal has estimated Canada's oil reserves at over 175 billion barrels - the second largest in the world.

The latest forecast is based on a survey of all oil sands producers that CAPP conducted in early 2010. A 100 per cent response rate was obtained from CAPP member companies. Estimates based on publicly available information were used to include any of the projects by non-members for which the survey did not cover. From this data, CAPP adjusted the startup date and production profile for each project or expansion phase, as was necessary, to reflect its assessment of the outlook for the project and the historical performance trends of the industry. The forecasted year over year growth took into account the availability of capital and labour and the experience of the project operators. Producers were requested to use their own expectations for future crude oil prices in determining the production profile from their projects.

CAPP's forecast of conventional production was established based on internal analysis and a series of informal discussions with various provincial government departments and agencies.

Table 2.1 Canadian Crude Oil Production

million b/d	2009	2015	2020	2025
Growth	2.72	3.29	3.88	4.34
Operating & In Construction	2.72	3.20	3.16	2.98

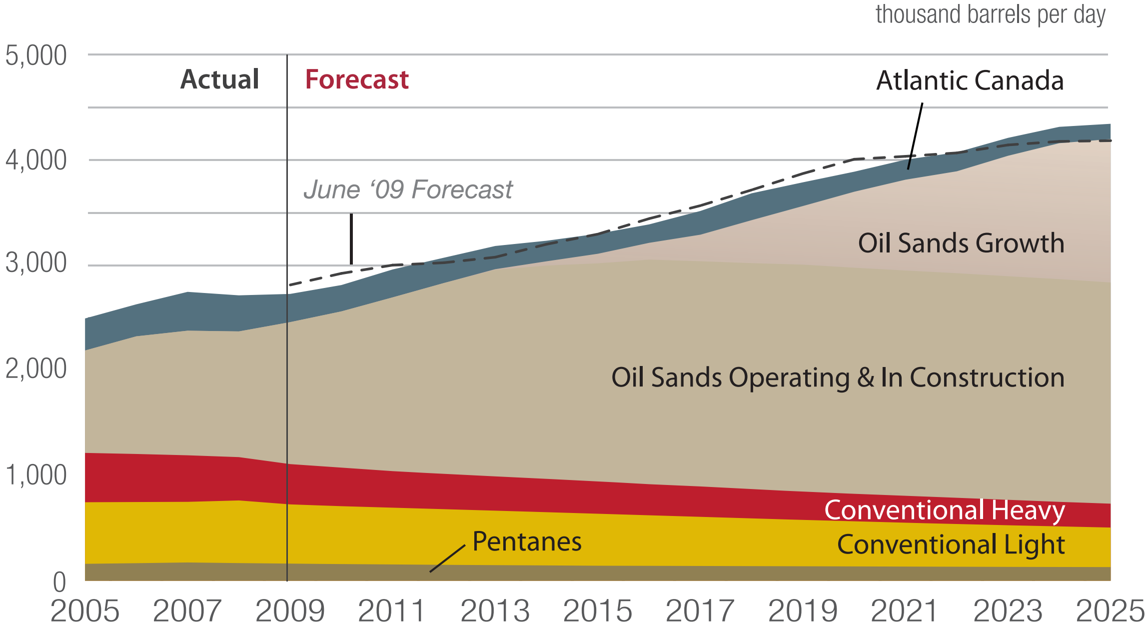
2.1 Canadian Crude Oil Production

The Western Canada Sedimentary Basin (WCSB) which underlies most of Alberta, and parts of Saskatchewan, British Columbia, Manitoba and the Northwest Territories is the primary source of Canadian crude oil production. In 2009, Canadian oil production was 2.7 million b/d with 2.5 million b/d sourced from western Canada.

In 2009, production in Atlantic Canada was 268,000 b/d, a decrease of almost 75,000 b/d from 2008 production that was primarily due to reduced production from the Terra Nova field and planned maintenance work at the White Rose field. Future declines in production from existing fields is expected to be tempered with increased production from satellite fields coming online in the near-term and then offset with the growth in production from Hibernia South and then the Hebron heavy oil project.

This year's expected forecast is referred to as the "Growth" Case. An additional case which includes only projects currently "Operating" or "In Construction", is shown to provide a foundation to the expected case (Figure 2.1). Table 2.1 shows that in the Growth Case, production is expected to reach 4.3 million b/d in 2025. Under the Operating & In Construction Case, production increases but then declines in the latter part of the forecast to 3.0 million b/d by 2025 primarily due to the fall in conventional production.

Figure 2.1 Canadian Oil Sands & Conventional Production



2.2 Western Canadian Crude Oil Production

In 2009, 2.4 million b/d of crude oil were produced from Western Canada with the majority of these volumes coming from the oil sands and the remaining portion recovered from conventional oil fields.

Table 2.2 shows the forecast for total western Canadian crude oil production in both cases. This latest forecast is similar to CAPP's 2009 forecast for most of the outlook period. However, where growth was previously essentially flat during 2020 to 2025, this latest forecast shows a steady and continued growth (Figure 2.2). This growth reflects a change in the activity status of certain projects and a higher likelihood that they will be developed. The production forecast in the Operating & In Construction Case is higher than in the previous forecast with the inclusion of additional projects that are currently under active development (Figure 2.4).

Table 2.2 Western Canadian Crude Oil Production

million b/d	2009	2015	2020	2025
Growth	2.45	3.10	3.69	4.19
Operating & In Construction	2.45	3.01	2.97	2.83

2.2.1 Oil Sands

Oil sands production currently makes up 55 per cent of western Canada's total crude oil production. In the Growth Case, production is expected to grow from over 1.3 million b/d in 2009 to approximately 2.2 million b/d in 2015 and to about 3.5 million b/d in 2025. Given signs of the beginning of economic recovery, oil sands producers are proceeding with a more balanced pace of development. Producers have returned many projects back to active development but remain mindful to establish a more controlled cost environment as they remain cautious with their estimates for future oil prices.

The exploration costs associated with oil sands production are relatively insignificant because the location of the resource is well known. However, the development costs are high. Costs associated with either open-pit mining techniques or steam injection to recover bitumen located further below the surface are higher than for conventional production. In addition, costs are being incurred to manage the effect of oil sands development on the environment as industry continues to look for ways to minimize its environmental footprint.

Figure 2.2 Growth Case - Western Canada Oil Sands & Conventional Production

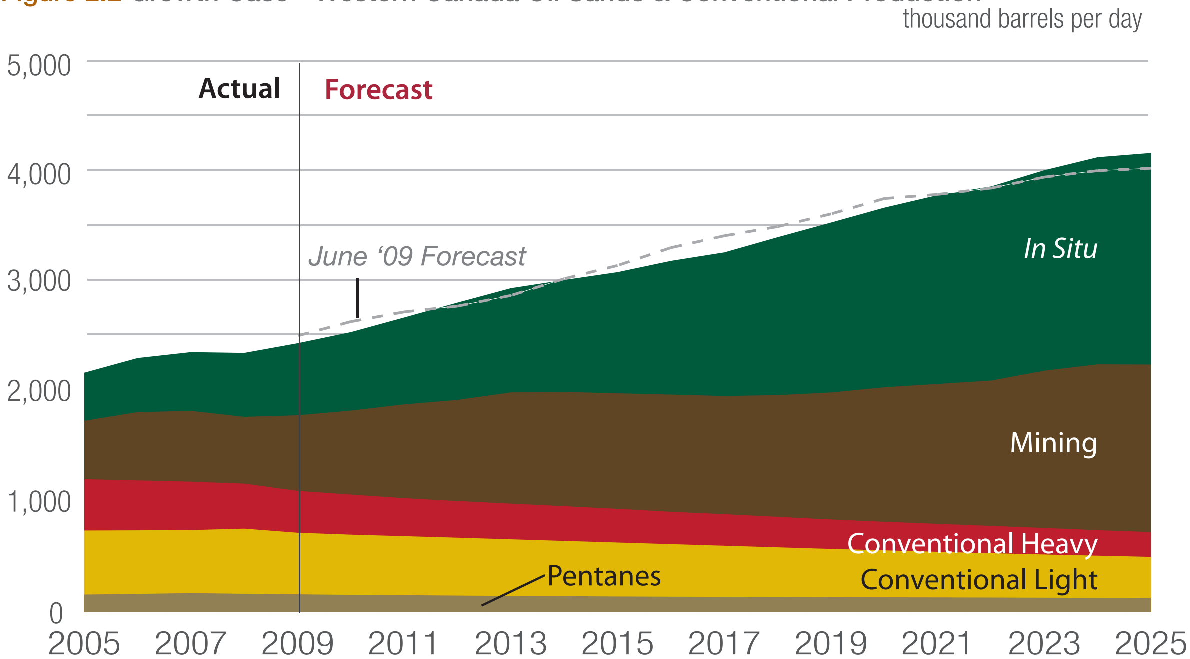


Figure 2.3 Oil Sands Regions

Canada's oil sands deposits are divided into three major regions in northern Alberta referred to as the Athabasca, Cold Lake and Peace River deposits (Figure 2.3). The Alberta Energy Resources and Conservation Board (ERCB) estimated at year-end 2008, that these areas contain remaining established reserves of 170 billion barrels.

Of the remaining established reserves in Alberta, 135 billion barrels, or 80 per cent, is considered recoverable by *in situ* methods and 35 billion barrels from surface mining. *In situ* recovery includes both primary methods, which are similar to conventional production, and methods whereby steam, water, or other solvents are injected into the reservoir to reduce the viscosity of the bitumen, allowing it to flow to a vertical or horizontal wellbore.

There are also smaller deposits in northwest Saskatchewan, next to the Athabasca oil sands deposit. The Saskatchewan Ministry of Energy and Resources has estimated 2.7 million hectares of potential land but the resource base has not been officially determined.

In 2009, over half of the total oil sands production was mined. Currently, all mined bitumen is upgraded as part of an overall integrated operation. However, bitumen production from the Imperial Kearl Lake mining project, which is slated to come online in 2012, will not be affiliated with its own upgrader. In addition, a recent update on the future expansion at Syncrude notes that bitumen production will exceed the upgrader's processing capacity. Under current conditions where a narrow price differential exists between light and heavy crude oil, the economics of building new upgrading facilities are not favorable.

Recovery of raw bitumen using *in situ* methods is set to surpass production from mining methods by 2016. Currently, of the *in situ* projects in operation, only the Long Lake Project operated by Nexen Inc. is coupled with upgrading facilities. Also, production from the Suncor Firebag and MacKay River projects are upgraded at Suncor's facilities. Otherwise, the majority of *in situ* bitumen production is not upgraded prior to reaching markets.

The integrated mining and upgrading projects in operation are listed below:

- The Suncor Steepbank and Millennium Mine;
- The Syncrude Mildred Lake and Aurora Mine;
- The Athabasca Oil Sands Project (AOSP); and
- The CNRL Horizon Project, which produced its first oil in February 2009.

In 2010, production from the CNRL Horizon Project is expected to continue to ramp up as the project reaches design capacity. The expansion by Syncrude, the Shell Jackpine and the Imperial Kearl Lake Project, are the three major mining projects currently under construction.

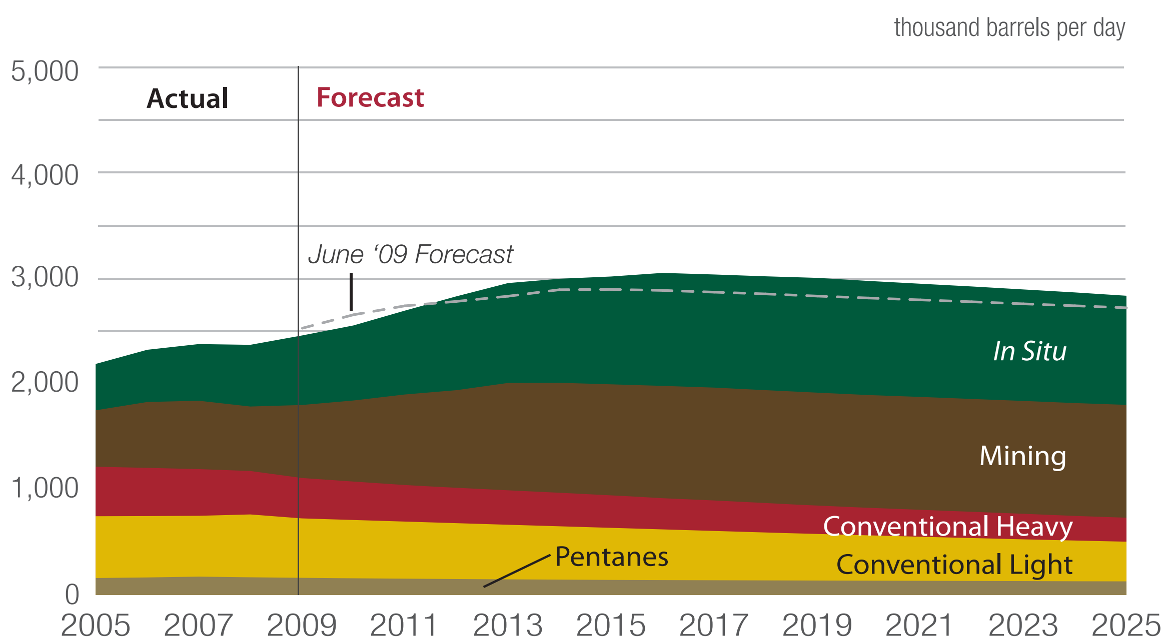
In the Operating & In Construction Case, oil sands production is expected to grow from over 1.3 million b/d in 2009 to approximately 2.1 million b/d in 2015 and beyond (Figure 2.4). Please refer to Appendices B.1 and B.2 for detailed production data tables.

2.2.2 Conventional Crude Oil Production

The WCSB is a mature basin and conventional crude oil production has been declining for years. In 2009, overall conventional production was 946,000 b/d, which was almost 6 per cent lower than production in 2008. However, this decline rate is expected to slow with renewed interest in the Cardium oil formation in Alberta, which is causing optimism in the industry similar to that generated by the Bakken formation in Saskatchewan over the last several years.

As of 2008, the Alberta Geological Survey estimated that over 70 percent of the 1.9 billion barrels of initial established recoverable reserves in the Cardium oil formation was already produced. While the Cardium oil play is not a new discovery, the use of horizontal drilling combined with fracturing stimulation techniques, has dramatically increased the potential recovery factor in these fields.

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



In March 2010, the Alberta Government announced that effective January 2011, it would make permanent an incentive feature of its royalty system program that limits the royalty rate on new conventional oil wells for the first 50,000 barrels of production to five per cent. In addition, the government announced that the maximum royalty rate for conventional oil would be reduced at higher price levels from 50 per cent to 40 per cent. These fiscal initiatives should improve the attractiveness of developing conventional oil resources in Alberta and help to stimulate production from these resources.

Saskatchewan light crude oil production increased by a modest one per cent in 2009. This growth is attributed to the light oil production from the Bakken oil formation in south east Saskatchewan. The Bakken play is considered one of the most attractive conventional oil plays in Canada. The decline in heavy crude oil production in Saskatchewan has been offset somewhat by the production from the Lower Shaunavon field.

In Manitoba, the use of newer technology has also played a major role. In 2009, production rose nine per cent due mostly to the increased use of horizontal drilling wells that recover significantly more crude oil than traditional vertical wells. As a result, a higher production rate than previously forecast is expected to be maintained over the next few years.

2.3 Western Canadian Crude Oil Supply

The bitumen produced from the oil sands is a form of heavy crude oil that is so viscous that it must be either converted into light crude oil, or diluted with lighter hydrocarbons in order to be transported by pipeline to market. The distinction between the various types of crude oil supplies is important since refineries are configured to process particular crude oil types. On a volumetric basis, supply is greater than production due to the inclusion of imported condensate needed to supplement the locally produced volumes of condensate used to dilute non-upgraded bitumen production for transport to market.

The CAPP forecast categorizes the various crude oil types that comprise western Canadian crude oil supply into four major categories: Conventional Light, Conventional Heavy, Upgraded Light and Bitumen Blend. The “Bitumen Blend” category 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”). The most common form of Bitumen Blend is bitumen blended with a standard condensate such as pentanes plus, which is mainly recovered from processing natural gas, to create a type of crude oil that meets pipeline specifications for density and viscosity. An example of such a Dilbit would be Cold Lake crude, which has a density of about 930 kg/m^3 (21° API) and a sulphur content of 3.6 per cent. Blending for dilbit requires a 70:30 bitumen to condensate ratio while blending for synbit changes the ratio to approximately 50:50.

Although the main source of diluent is natural gas condensate that is produced in western Canada, the needs of growing bitumen production exceeds this diluent supply. An average of over 60,000 b/d of diluent were imported into Alberta by rail in 2009. This latest forecast is not constrained by the availability of condensate imports. Imports are expected to increase once the Enbridge Southern Lights pipeline is in service in July 2010. The forecast assumes that demand for condensate imports will exceed the pipeline’s initial capacity of 180,000 b/d by 2015, so an expansion of this pipeline may be required.

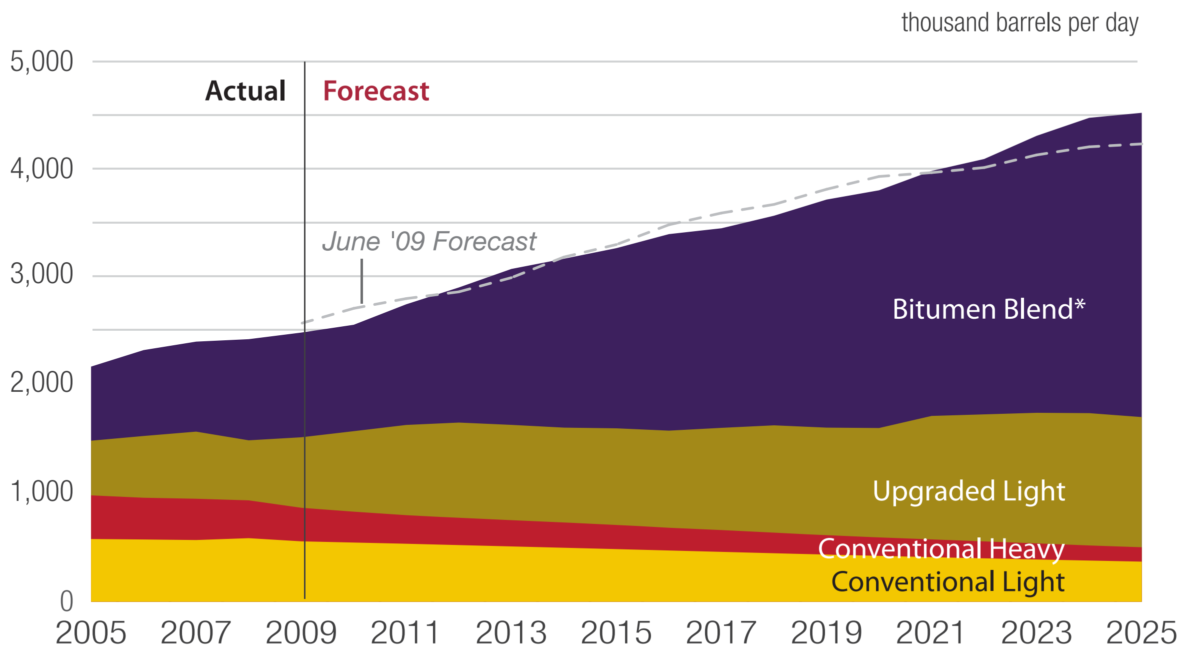
Some producers have indicated their intention to use upgraded light crude oil as diluent instead of condensate. Conseqently, this latest forecast reflects a greater use of upgraded synthetic crude oil as a source of diluent than the 2009 forecast did. Thus for a given level of bitumen production, crude oil supply levels will be correspondingly lower than would be the case in the previous forecast where more imported condensate was anticipated to be used as diluent.

Table 2.3 Western Canadian Crude Oil Supply

million b/d	2009	2015	2020	2025
Growth	2.49	3.28	3.81	4.53
Operating & In Construction	2.49	3.17	3.13	3.00

Table 2.3 shows the projections for total western Canadian crude oil supply. Please refer to Appendices B.3 and B.4 for detailed data. In the Growth Case, Upgraded Light crude oil supply is projected to grow from about 653,000 b/d in 2009 to 896,000 b/d in 2015 and 1.2 million b/d by 2025.

Figure 2.5 Growth Case - Western Canada Oil Sands & Conventional Supply



* Bitumen Blend includes some volumes of upgraded heavy sour crude oil and bitumen blended with diluent or ugpraded crude oil.

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

- Upgraders that process conventional heavy oil, e.g., the Husky Upgrader at Lloydminister and the CCRL Upgrader in Regina;
- Integrated mining and upgrading projects, e.g., Suncor, Syncrude and CNRL operations;
- Integrated *in situ* projects, e.g., the Nexen Long Lake project;
- Offsite upgraders, e.g., the Athabasca Oil Sands Project; and
- One Merchant Upgrader

Compared to the 2009 forecast, the Upgraded Light crude oil supply is lower since many companies have reconsidered building upgrading facilities and more projects anticipate using more upgraded crude oil as diluent. Correspondingly, Bitumen Blend, which makes up the heavy crude oil supply from the oil sands, is forecast to increase from 970,000 b/d in 2009 to 1.7 million b/d in 2015 and up to 2.8 million b/d in 2025 (Figure 2.5).

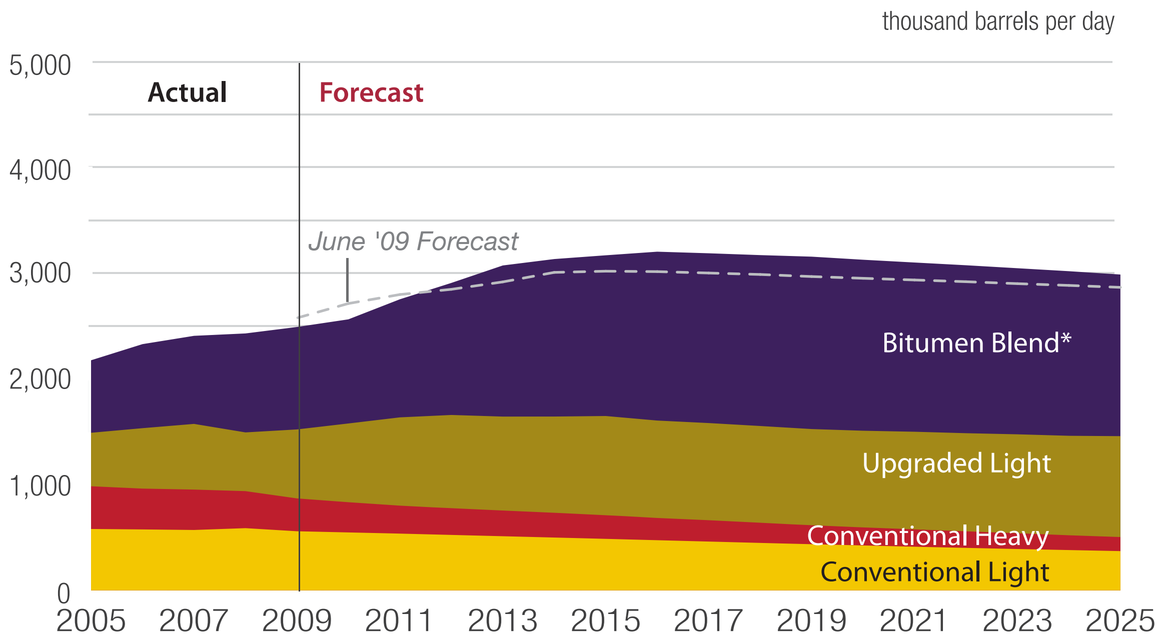
In the Operating & In Construction Case, the limited growth projected from the oil sands projects can no longer offset the declines in conventional production by 2015 (Figure 2.6). The supply of Upgraded Light crude oil is forecast to grow from 653,000 b/d in 2009 to 940,000 b/d in 2015. Bitumen Blend is forecast to grow from 970,000 b/d in 2009 to 1.5 million b/d in 2015. From 2015 to the end of the forecast period, supply of both upgraded light crude oil and Bitumen Blend is essentially flat. In this case, there would be sufficient condensate imports available throughout the forecast period once the Enbridge Southern Lights Diluent Pipeline is in service.

2.4 Methodology

CAPP did not survey conventional crude oil producers but instead relied upon historical trends, recent announcements and discussions with provincial government representatives to derive its forecast.

From the results of the survey of oil sands producers, CAPP determined the amount of upgraded crude oil and bitumen that could potentially be available to the market.

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



* Bitumen Blend includes some volumes of upgraded heavy sour crude oil and bitumen blended with diluent or ugpraded crude oil.

The following key assumptions have been used to determine available oil sands supply:

a) All bitumen must be blended with either condensate or upgraded light crude oil to meet pipeline specifications;

b) Condensate is the preferred diluent over upgraded light crude oil;

c) In July 2010, the Southern Lights Pipeline will provide additional diluent to western Canadian producers;

d) Prior to the in service of the Southern Lights Pipeline, railed imports will compensate for the shortfall of western Canadian condensate required by producers.

2.5 Crude Oil Production and Supply Summary

The overall production forecast is similar to the 2009 outlook. The average annual growth rate in oil sands production is six per cent over the forecast period. The 2009 volumes of oil sands production of 1.3 million b/d is forecast to increase to 2.2 million b/d in 2015 then to 3.5 million b/d by 2025. Many oil sands producers that previously put projects on hold have now confirmed that they will proceed with these projects given the more favorable economic outlook. Other projects are also considered more likely to proceed given the support of new investment capital.

Some companies have redefined the scope of their projects and have excluded the building of upgrading facilities as light and heavy oil price differentials have narrowed. As a result of this and the anticipated greater use of Upgraded Light crude oil as a diluent, the supply from western Canada will be comprised of more heavy crude oil and less light crude oil volumes than previously forecast.

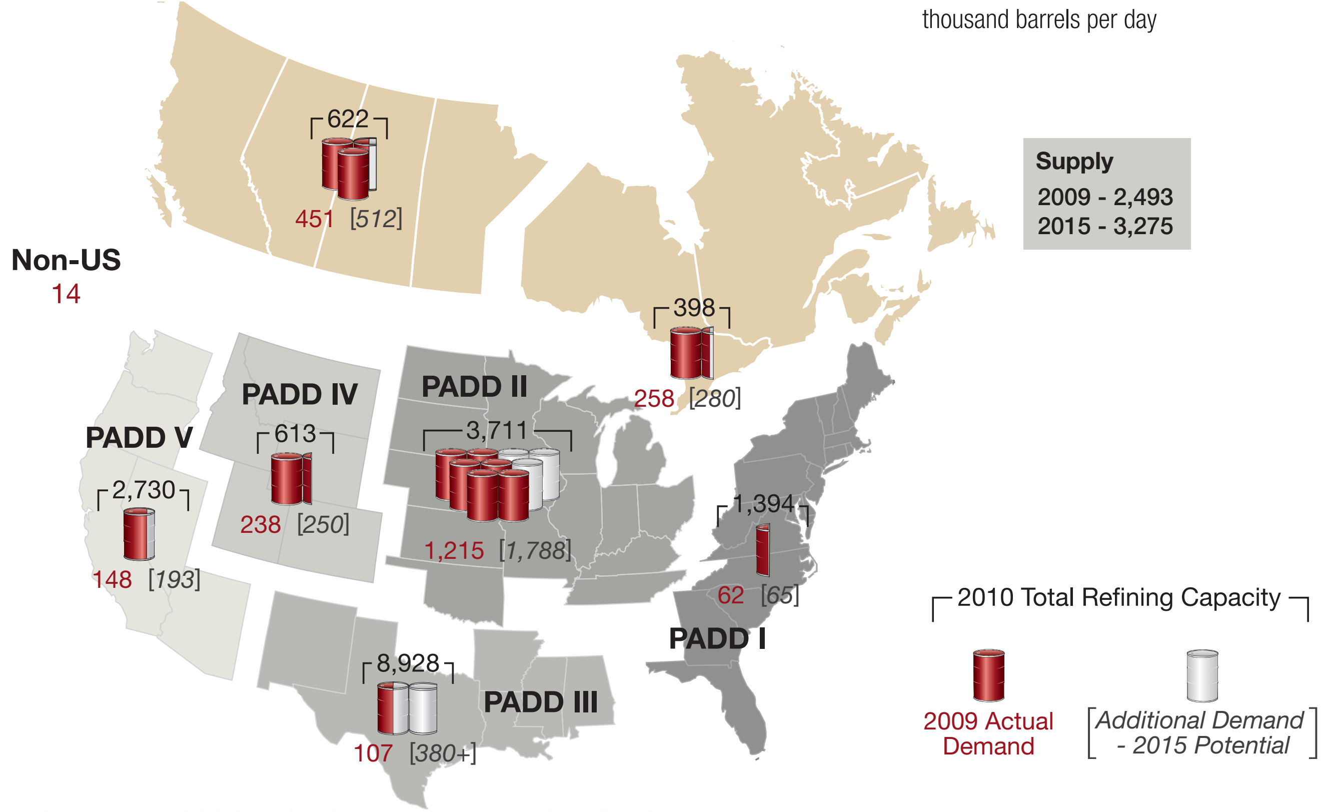
The use of newer technology is expected to increase light oil production in mature fields in Saskatchewan, Alberta and Manitoba during the next few years. Production from Atlantic Canada is expected to increase in 2017 once the Hebron Project is online.

3 CRUDE OIL MARKETS

The markets that hold the greatest potential to be supplied by western Canadian crude oil producers depends on a number of fundamental characteristics including: the availability of alternative sources of supply; the size of the market; and feedstock requirements. Thus, the location, size and the number of refineries in an area configured to process the types of crude oil produced in Canada are particularly relevant considerations. In early 2010, CAPP surveyed refineries in Canada and the U.S. to determine their current capability and future plans to process additional supplies from Canada (Figure 3.1).

In 2009, available crude oil supply from western Canada was 2.5 million b/d. Domestic demand for western Canadian crude oil was 709,600 b/d and the remaining supply of over 1.8 million b/d or 72 per cent was exported (Figure 3.1). Eastern PADD II (particularly, Illinois, Indiana, Michigan, Ohio and Minnesota) is the largest market for western Canadian crude oil. The other primary markets are currently: British Columbia; Alberta; Saskatchewan; Ontario; PADD IV; California and Washington in PADD V. Once all approved pipeline projects are in service, western Canadian crude oil supplies will have an opportunity to capture a greater share of the large U.S. Gulf Coast refinery market.

Figure 3.1 Market Demand for Western Canadian Crude Oil – Actual 2009 vs 2015 Potential



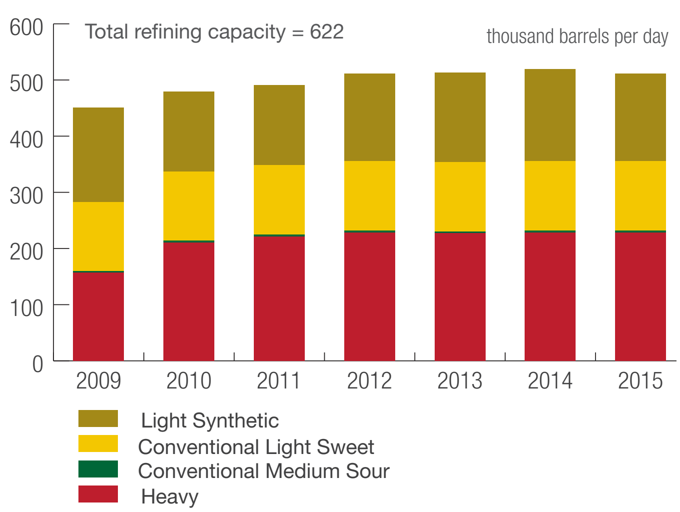
3.1 Canada

Canadian refineries that have access to western Canadian crude oil have a total refining capacity of over one million b/d. In 2009, these refineries processed about 709,600 b/d of western Canadian crude oil. This is expected to increase to approximately 791,600 b/d by 2015 with planned refinery expansions.

3.1.1 Western Canada

There are eight refineries located in western Canada with a total refining capacity of about 622,000 b/d. These refineries process western Canadian crude oil exclusively. In 2009, they received 451,100 b/d of crude oil and this is expected to increase to 511,700 b/d in 2015 (Figure 3.2). The Moose Jaw asphalt plant in Moose Jaw, Saskatchewan produces mostly asphalt while other refineries manufacture a wide range of petroleum products.

Figure 3.2 Western Canada: Forecast Western Canadian Crude Oil Receipts



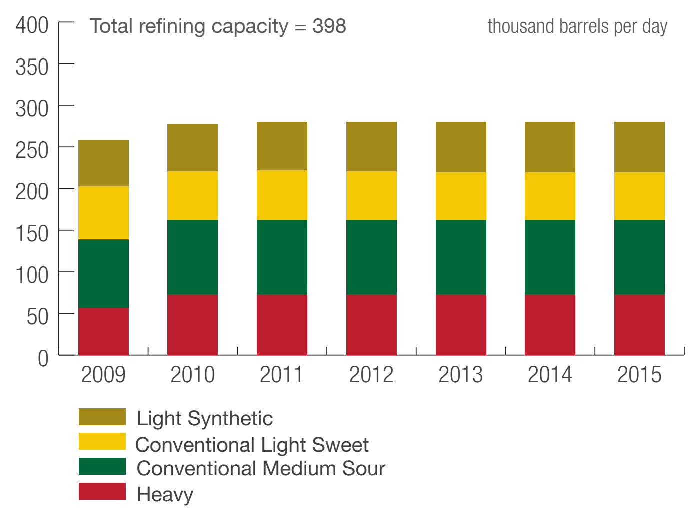
Receipts of conventional light sweet crude oil are expected to be flat. Suncor's (previously Petro-Canada's) Edmonton refinery is expected to operate more efficiently over time as its conversion project was just completed in January 2009. The refinery is configured to process 100 per cent oil sands feedstock, which consists of mostly heavy crude oil. The increase in the use of light synthetic crude oil as feedstock in 2012 is related to plans for the Consumers' Co-operatives refinery located in Regina to expand by 30,000 b/d.

3.1.2 Ontario

There are four refineries (excluding the Nova Chemical refinery and petrochemical complex in Sarnia) located in Ontario with a total refining capacity of 398,000 b/d. These refineries process western Canadian crude oil as well as crude oil (foreign imports and Atlantic Canada production) that is received by tankers via the Portland-to-Montréal Pipeline and, subsequently transported on the Enbridge Montréal-to-Sarnia Pipeline (Line 9). Ontario refineries have, for a number of years, selected their feedstock sources based on both availability and pricing.

According to Statistics Canada, Ontario refineries received 339,500 b/d of crude oil in 2009 from the following sources: Western Canada (258,500 b/d or 76 per cent); Eastern Canada (12,100 b/d or 4 per cent); United States (13,600 b/d or 4 per cent); Saudi Arabia (12,800 b/d or 4 per cent); the United Kingdom (10,500 b/d or 3 per cent); and other foreign sources (32,000 b/d or 9 per cent). Receipts of western Canadian crude oil are projected to remain flat for the forecast period (Figure 3.3).

Figure 3.3 Ontario: Forecast Western Canadian Crude Oil Receipts



3.1.3 Québec

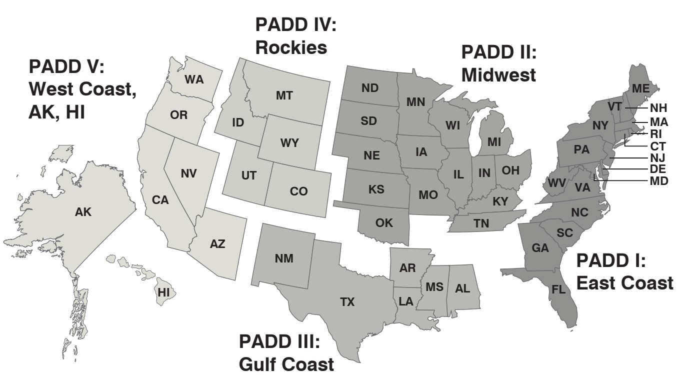
Québec had three refineries. In November 2009, Shell announced plans to close its refinery in Montréal and transform the facility into a terminal. The remaining Montréal refinery is owned by Suncor (previously Petro-Canada) and has a capacity of 130,000 b/d. The refinery in Québec City has a capacity of 265,000 b/d.

The Montréal refinery can process crude from both eastern Canada and foreign sources received from the Portland-to-Montréal pipeline. In September 2009, Suncor announced that the previously proposed project for the addition of a 25,000 b/d coker at its refinery in Montréal has been cancelled. The reasons cited include a change of market conditions and the need to select the optimal investment opportunities from the many available following the Suncor and Petro-Canada merger.

3.2 United States

The United States, with a total refining capacity of almost 18 million b/d, is the world's largest oil market. In 2009, Canada was by far the largest exporter of crude oil to the U.S., significantly ahead of other exporting countries including, Venezuela, Mexico and Saudi Arabia. Canada exported over 1.9 million b/d, which was equivalent to 22 per cent of total U.S. imports from foreign sources. Of this volume, 1.8 million b/d was sourced from Western Canada (Figure 3.1) The U.S. demand for western Canadian oil supply is expected to reach 2.7 million b/d in 2015. The bulk of this growth is expected to be heavy crude oil. Although overall U.S. crude oil demand is not expected to increase significantly, western Canadian crude oil should supply a growing share of this market. Declines in imports from other major suppliers to this market is expected due to either falling production or a focus on expanding into new export markets such as Asia, where significant oil demand is expected in the future.

Figure 3.4 Petroleum Administration for Defense Districts

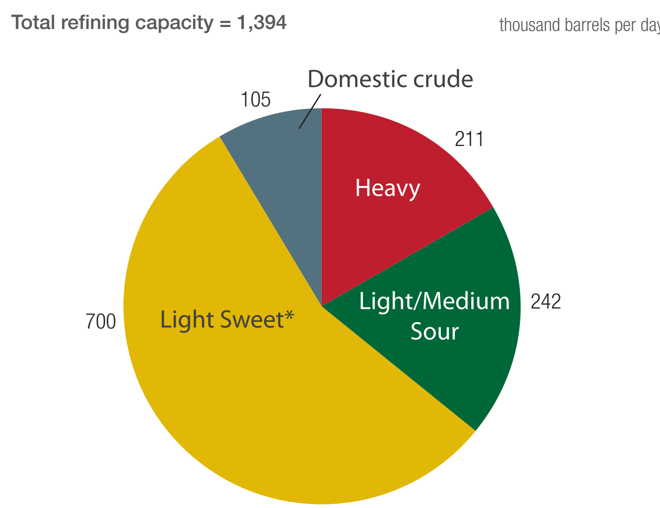


The U.S. Department of Energy divides the 50 states in the U.S. into five Petroleum Administration for Defense Districts or PADDs (Figure 3.4). The PADDs were originally delineated during World War II for oil allocation purposes and remain the convention for describing U.S. oil markets.

3.2.1 PADD I (East Coast)

PADD I is located along the east coast of the United States. There are 11 refineries in Georgia, New Jersey, Pennsylvania, Virginia and West Virginia with a total capacity of almost 1.4 million b/d. Refineries on the East coast are more vulnerable to closures due to age, location and easy access to petroleum products from European refineries. Notably, Sunoco and Valero both shut down their refineries during 2009, resulting in a loss of refining capacity of about 360,000 b/d. A combination of operational issues, maintenance shutdowns and refinery closures resulted in lower overall volumes of crude oil processed in PADD I in 2009 compared to 2008.

Figure 3.5 2009 PADD I: Foreign Sourced Supply by Type and Domestic Crude Oil



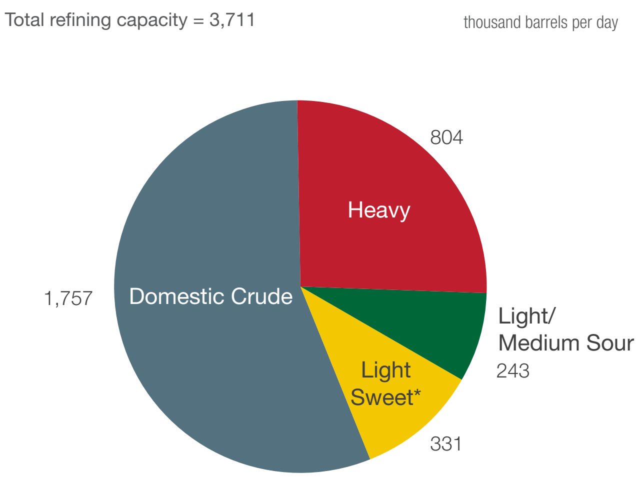
* Includes small volumes of Medium Sweet
Source: EIA

In 2009, imports of foreign crude oil by refineries in PADD I totaled 1.1 million b/d and over 60 per cent of these volumes were light crude (Figure 3.5). PADD I imported 211,800 b/d of crude oil from Canada. About 61,700 b/d came from western Canada and was primarily delivered by pipeline to the United refinery in Warren, Pennsylvania. Deliveries of western Canadian crude oil into this market is expected to remain flat through to 2015.

3.2.2 PADD II (Midwest)

PADD II is located in the U.S. Midwest and has historically been the single largest market for western Canadian crude oil, with a refining capacity of 3.7 million b/d. In 2009, PADD II refineries received almost 1.4 million b/d of foreign sourced crude oil and over half these volumes were heavy crude oil (Figure 3.6). Crude oil from western Canada totaled over 1.2 million b/d, making Canada the primary supplier.

Figure 3.6 2009 PADD II: Foreign Sourced Supply by Type and Domestic Crude Oil



* Includes small volumes of Medium Sweet
Source: EIA

The technological advancements used on the Bakken shale deposit in North Dakota can be largely credited for the state's production growth in light oil in recent years. This increase in domestic production has reduced the need for crude oil imports. Current imports of heavy oil supplies from western Canada have already saturated this market. Although there are plans for some refineries to upgrade and increase their capacity for refining heavy crude oil, the increased growth in supplies of heavy western Canadian crude oil is expected to exceed the additional volumes that could be processed at refineries in this traditional market.

The U.S. Energy Information Administration further divides PADD II into three refining districts, which is used in the following discussion.

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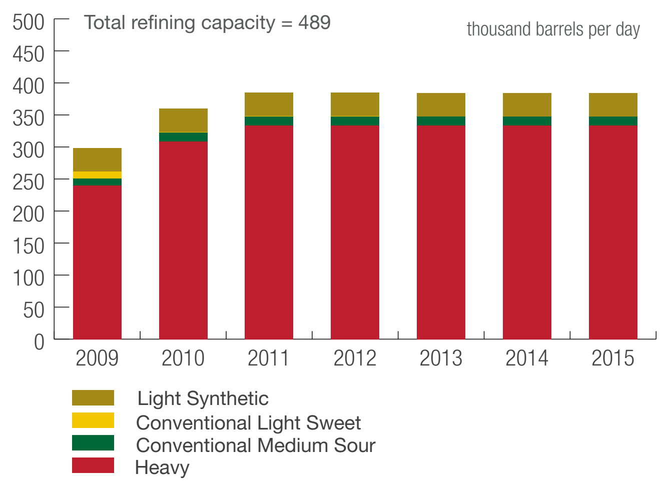
Northern PADD II

Northern PADD II consists of North Dakota, South Dakota, Minnesota and Wisconsin. There is one refinery in both North Dakota and Wisconsin and two refineries in Minnesota. These four refineries have a total refining capacity of 489,000 b/d. In 2009, imports into northern PADD II were 298,400 b/d and western Canadian crude oil accounted for almost all of it. Imports of western Canadian crude oil are expected to grow to 384,900 b/d by 2011 and remain flat afterwards (Figure 3.7). The Minnesota refineries owned by Flint Hills and Marathon Oil, have access to western Canadian crude oil supplies via the Minnesota Pipeline, which has a capacity of 465,000 b/d.

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



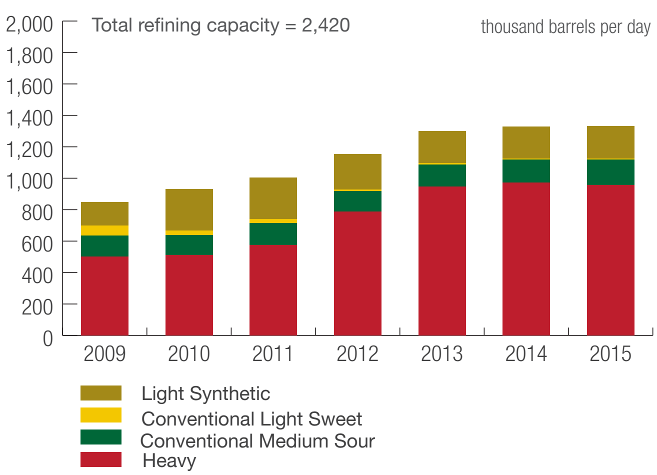
Eastern PADD II

Eastern PADD II consists of Michigan, Illinois, Indiana, Kentucky, Tennessee and Ohio and has 14 refineries with a total refining capacity of 2.4 million b/d. In 2009, western Canadian crude oil accounted for 848,600 b/d or 86 per cent of the total foreign imports into the region. Some previously proposed expansions have been cancelled but there are a number of active refiner upgrades that will result in higher runs of western Canadian heavy crude oil in the next several years. The majority of growth in western Canadian supplies will be heavy crude oil types, so these upgrades provide the opportunity for western Canadian crude oil to meet this new growth in demand (Figure 3.8). Table 3.1 summarizes the projects designed to process additional volumes of Canadian crude oil.

Table 3.1 Summary of Announced Refinery Upgrades in Eastern PADD II

Operator	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Description
WRB Refining	Roxana, IL	306	2011	Add a 65,000 b/d coker; increase total crude oil refining capacity by 50,000 b/d; increase heavy oil refining capacity to 240,000 b/d
BP	Whiting, IN	400	2012	Construction of new coker and a new crude distillation unit
Marathon	Detroit, MI	102	Mid 2012	Increase heavy oil processing capacity by 80,000 b/d and increase total crude oil refining capacity to 115,000 b/d
Valero	Memphis, TN	195	2012	Cat-cracking unit upgrade

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



Southern PADD II

Southern PADD II has seven refineries located in Kansas and Oklahoma with a total refining capacity of 802,000 b/d. The two refineries in Tulsa, Oklahoma are counted as one since Holly acquired the Sinclair refinery in December 2009 with the intention to operate the two facilities on an integrated basis. The Enbridge Spearhead pipeline was expanded in April 2009 to 190,000 b/d. The capacity of this pipeline currently limits the volumes of crude oil that western Canadian producers are able to deliver into Cushing, Oklahoma. This constraint will be removed once TransCanada's Keystone Extension is in service.

Cushing is a hub that receives crude oil predominantly from pipelines transporting offshore crude oil delivered by tanker to the U.S. Gulf Coast. This crude oil is then distributed by a number of pipelines exiting the hub which serve refineries throughout the PADD II and PADD III regions. Thus access to the Cushing hub offer western Canadian crude oil producers some opportunities to penetrate new markets through the connected pipeline network in the region.

In 2009, refineries in this market received about 67,800 b/d of western Canadian crude oil (Figure 3.9).

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

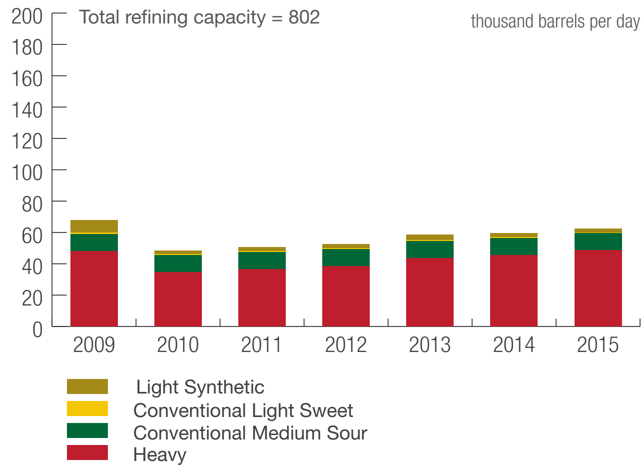
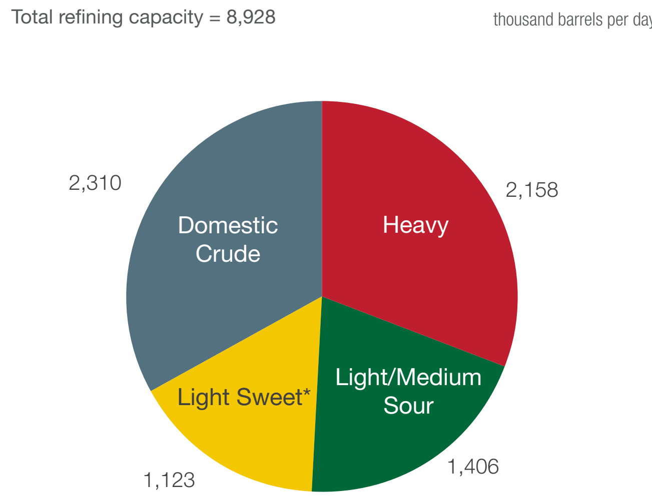


Figure 3.10 2009 PADD III: Foreign Sourced Supply by Type and Domestic Crude Oil



* Includes small volumes of Medium Sweet
Source: EIA

3.2.3 PADD III (Gulf Coast)

PADD III is comprised of Alabama, Arkansas, Louisiana, Mississippi, New Mexico and Texas. There are 50 refineries in this market with a total refining capacity of over 8.9 million b/d, of which a significant portion has heavy crude oil processing capabilities. It is the largest and most complex refining district in the United States and is considered to be potentially well suited and capable of processing Canadian heavy crude oil.

In 2009, PADD III imported 4.7 million b/d of crude oil from foreign sources, of which 2.2 million b/d was heavy crude oil (Figure 3.10). The majority of these imports were sourced from Mexico (21 per cent), Venezuela (17 per cent), Saudi Arabia (12 per cent), and Nigeria (11 per cent). Deliveries of western Canadian heavy crude oil to this market totaled about 121,500 b/d. Currently, the only pipeline access for delivery of western Canadian crude oil to the Gulf Coast is through the ExxonMobil Pegasus Pipeline. This pipeline, which originates at Patoka, Illinois, has a capacity of 96,000 b/d and ends at Nederland, Texas. In addition, approximately 11,700 b/d was shipped off the Westridge dock in Burnaby, British Columbia and arrived via tanker in 2009. About 13,500 b/d of light sweet crude was also imported from Atlantic Canada by tanker.

The steep decline in production from Mexico's Cantarell field could make securing supply from Canada more attractive in the future. In addition, Canada's other major competitor, Venezuela, has recently signed agreements to ship oil to other markets such as China. In recent years, PADD III refineries have added several new cokers which will enable them to run heavier and more sour grades of crude oil, which are becoming increasingly predominant in the world's crude oil production slate. Of note, Marathon Oil completed a major expansion at its refinery at Garyville, Louisiana that almost doubled its previous capacity in 2009. An additional 15,000 b/d of capacity was also added by Holly Corp's expansion of its refinery at Artesia, New Mexico.

Table 3.2 summarizes the major refinery upgrades announced for the region. Although these upgrades may not be all specifically designed to process Canadian crude oil, many of these companies have confirmed that their refineries are expecting to take more Canadian crude oil. Thus, the main constraint to the growth of supply of western Canadian heavy crude to this region is not available refining capacity but is in fact the availability of pipeline capacity to the region. The construction of the Canadian portion of the Keystone XL Pipeline was approved in early 2010. This pipeline project is scheduled to be completed in 2013 and once in operation, it will add pipeline capacity to the U.S. Gulf Coast. In 2015, CAPP has estimated that this market could receive at least 380,000 b/d of western Canadian crude oil based on current contractual commitments.

Table 3.2 Summary of Major Announced Refinery Upgrades in PADD III

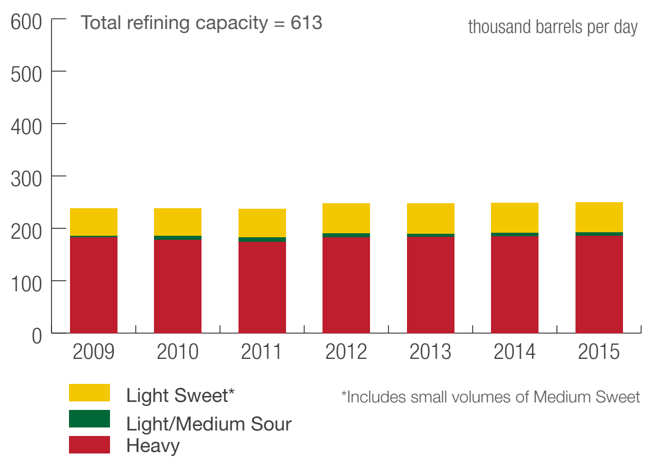
Operator	Location	Current Capacity (thousand b/d)	Scheduled In-Service	Description
Hunt Refining	Tuscaloosa, AL	52	2010	Increase capacity to 65,000 b/d
Valero	St. Charles, LA	250	2012	New 45,000 b/d hydrocracker and 10,000 b/d expansions to the crude and coker units
Motiva Enterprises	Port Arthur, TX	285	2012	Increase capacity to over 600,000 b/d

3.2.4 PADD IV (Rockies)

PADD IV includes the states of Colorado, Montana, Utah, Wyoming and Idaho. It has 14 refineries located in four of the five states (there are no refineries in Idaho), and has a total refining capacity of 613,700 b/d. Although PADD IV is smaller than the other core markets, it has been a stable market for western Canadian crude oil supply.

In 2009, PADD IV processed 238,000 b/d of Canadian crude oil or about 44 per cent of its feedstock requirements. Canada is the only source of foreign crude oil to this market. Throughout the forecast period, western Canadian crude oil receipts are forecast to remain relatively flat (Figure 3.11).

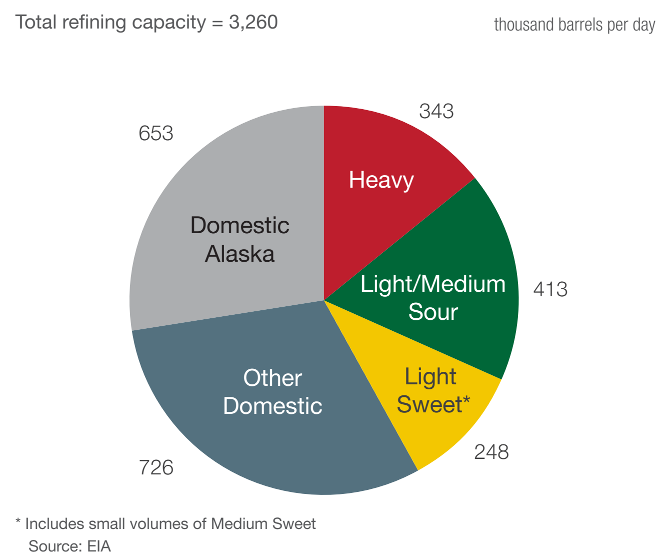
Figure 3.11 PADD IV: Forecast Western Canadian Crude Oil Receipts



3.2.5 PADD V (West Coast)

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

Figure 3.12 2009 PADD V: Foreign Sourced Supply by Type and Domestic Crude Oil



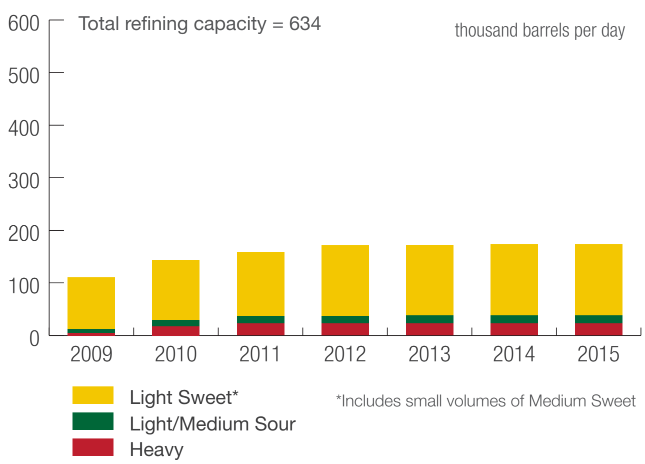
For the purposes of the remainder of this report, the PADD V market region will focus only on Washington and California, as these states represent both the current demand and future prospects for western Canadian crude oil.

Washington

There are five refineries in Washington that have a combined capacity of 634,000 b/d. Alaska is still the primary source of feedstock for these refineries, however, Alaskan production continues to decline. As a result, these refiners are becoming increasingly dependent on imports from Canada and other countries. In 2009, these refineries received 191,000 b/d of foreign crude oil, sourced primarily from Canada (58 per cent), Angola (11 per cent) and Saudi Arabia (13 per cent).

In 2009, receipts of western Canadian crude were 101,000 b/d. These receipts are expected to remain constant throughout the forecast period (Figure 3.13). Given the small size of this niche market, further development of this market is limited.

Figure 3.13 Washington: Forecast Western Canadian Crude Oil Receipts



California

California has 17 refineries with a total refining capacity of 2.1 million b/d. Most of the refineries are located near the coast in the Los Angeles area and in the San Francisco Bay area. These refineries account for almost 95 per cent of the refining capacity in the state. These refineries are among the most sophisticated in the world, partly due to California having the strictest environmental requirements in the United States for refined petroleum products. They have the capability to process a wide variety of crude oil types and are designed to yield a higher proportion of light products, such as gasoline. The three refineries in Bakersfield are smaller and process local California crude oil; they would not be expected to receive Canadian crude.

Californian refineries receive the majority of their supplies from California and Alaska. In 2009, 693,000 b/d of crude oil was imported from foreign sources. The top three countries that supplied these imports were Saudi Arabia (24 per cent); Iraq (19 per cent); and Ecuador (17 per cent). Canada only accounted for about six per cent of foreign imports.

The rate of decline of California production has eased over recent years compared to historical trends but the California Energy Commission still expects production to fall by 2 to 3 per cent per year in the future. Alaskan crude production is supplied primarily to Alaska and Washington, with the balance going to California. As production in Alaska continues to decline, the California refineries will need to replace their domestic crude oil sources with more imports.

3.3 Asia

Asia is the second largest world oil consumer market after North America and has attracted significant interest over the last few years because of its rising demand for energy. China is the largest consumer of oil after the United States and economic growth rates are expected to be relatively strong compared to other countries. Table 3.3 shows oil demand from 2007 to 2010 in the major Asian countries. The International Energy Agency (IEA) forecasts that oil demand from China will grow by eight per cent in 2010 with the anticipation of continued growth in the longer term. There are a number of pipeline project proposals which could take western Canadian crude oil to the west coast that could support growth in demand in this market.

Table 3.3 Total Oil Demand in Major Asian Countries

million b/d	2007	2008	2009	2010
China	7.57	7.89	8.51	9.16
India	2.97	3.09	3.26	3.33
Japan	5.04	4.78	4.36	4.28
Korea	2.24	2.17	2.22	2.22

Source: International Energy Agency (IEA), May 2010

3.4 Methodology

CAPP did not put any constraints on the data submitted by refiners nor were any alternate cases prepared. Some assumptions were made based on discussions with refiners and publicly available information.

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

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

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

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

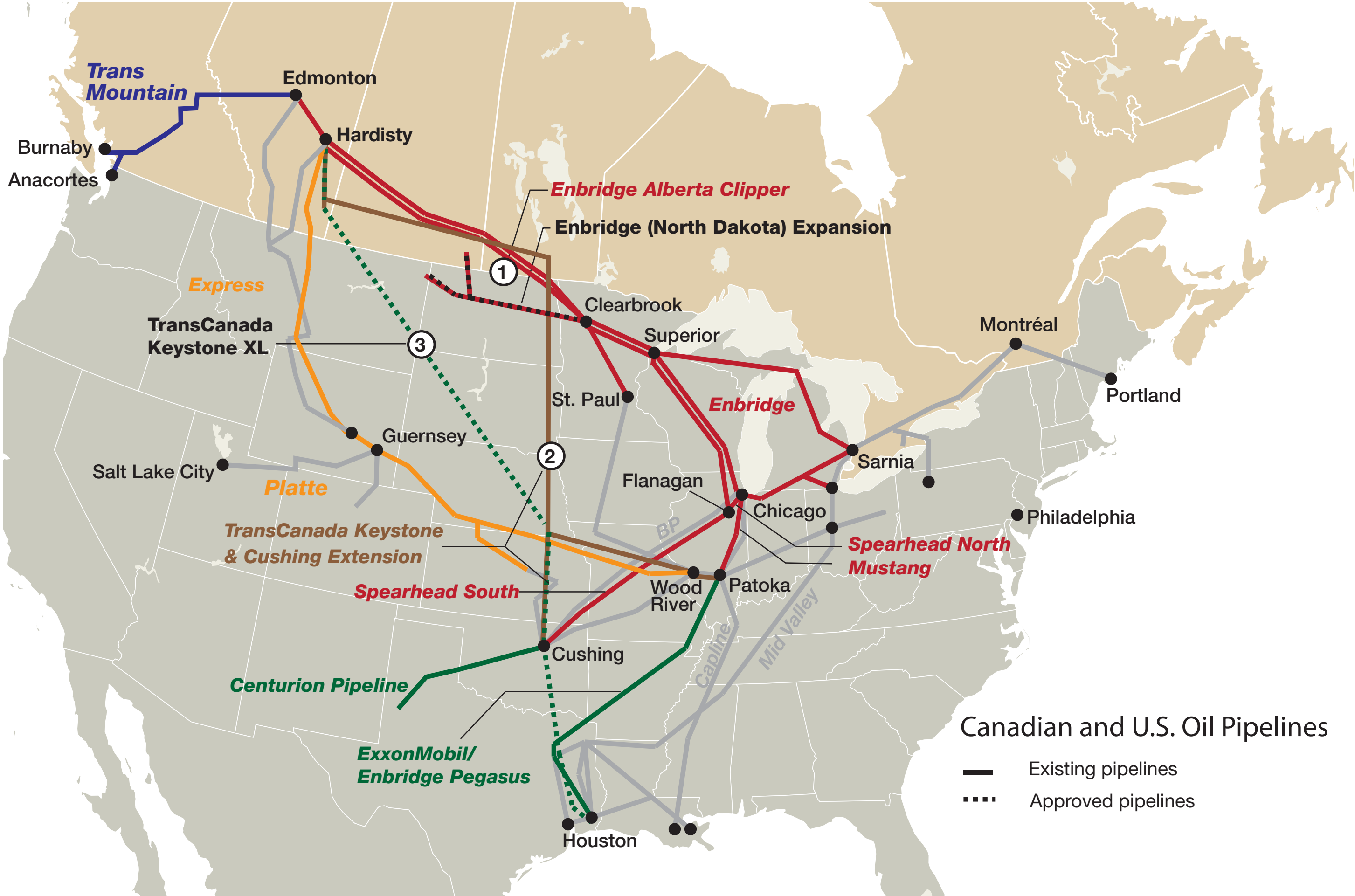
3.5 Markets Summary

Canadian crude oil supplies will continue to serve traditional markets. Demand in the U.S. Midwest market for Canadian crude will grow as heavy oil refining capacity in the region is added. However, growing volumes of Canadian heavy oil supply means that new markets for these volumes must be found. The U.S. Gulf Coast is one such market, and the Keystone XL Pipeline project, which is expected to be in service in 2013, will provide Canadian producers increased access to this market. Growing Asian oil demand also represents a potential future market for Canadian crude oil production.

4 CRUDE OIL PIPELINES

Pipelines are the most efficient method of transporting large volumes of crude oil over land. In recent years, expansion of the existing pipeline infrastructure has been required in order that growing volumes of western Canadian crude oil can serve traditional and new markets. In response, a number of pipeline expansions were completed in 2009 and two major additional pipelines will be operating by the end of 2010. Furthermore, additional capacity to major traditional markets and the U.S. Gulf Coast will be available once other scheduled pipeline projects are built and operating in the next few years. Given the forecasted growth in western Canadian crude oil supplies, there is expected to be significant excess capacity resulting from all these pipeline projects over most of the outlook period.

Figure 4.1 Existing and Approved Canadian and U.S. Crude Oil Pipelines



The existing pipeline network provides access to the primary markets for western Canadian crude oil which include: western Canadian refineries; Ontario, the U.S. Midwest; PADD IV; and the West Coast. There is also limited access to the U.S. Gulf Coast. The approved pipeline projects are primarily expansions into the U.S. Midwest and the Gulf Coast. There is also continuing interest in developing pipeline projects to the west coast to access other new offshore markets in the future. Figure 4.1 shows all existing and approved pipelines to date.

4.1 Existing Crude Oil Pipelines Exiting Western Canada

There are five major pipelines that are directly connected to the Canadian supply hubs at Edmonton and Hardisty, Alberta – Enbridge Mainline, Kinder Morgan Trans Mountain, Kinder Morgan Express, Enbridge Alberta Clipper and the TransCanada Keystone pipeline. Linefill for the Alberta Clipper and Keystone pipelines have begun and both pipelines are scheduled to be in service before the end of the year. These pipelines will add 885,000 b/d of pipeline capacity out of western Canada (Table 4.1).

Table 4.1 Capacity of Major Crude Oil Pipelines Exiting the WCSB

Pipeline	Crude Type	Annual Capacity (thousand b/d)
Enbridge	Light	1,072
	Heavy	796
Express	Light/heavy (35/65)	280
Trans Mountain	Light/heavy (80/20)	300
AB Clipper (new)	Heavy	450
Keystone (new)	Light/heavy (25/75)	435
Total Capacity		**3,333**

Enbridge Pipelines

The Enbridge system delivers crude oil and other refined products from western Canada to markets in western Canada, the U.S. Midwest and Ontario. It also receives crude oil from U.S. pipelines in the upper Midwest for deliveries to markets in the U.S. Midwest and Ontario. In addition, it connects to various pipelines in the U.S. such as the Minnesota Pipeline and Spearhead Pipeline, the latter providing access to the Cushing, Oklahoma pipeline hub.

The North Dakota Pipeline connects to the Enbridge Lakehead Pipeline at Clearbrook, Minnesota and provides producers in Montana and North Dakota with access to markets in PADD II and Ontario. Increased production in these areas has resulted in a need for additional pipeline capacity. The pipeline was expanded by 51,600 b/d to 162,000 b/d in January 2010. Further expansions in two phases are being considered. Phase 1 is targetted for 2011 and would provide 25,000 to 30,000 b/d of incremental capacity. Phase 2 is targetted for in service by the end of 2012 or early 2013 and would bring total incremental capacity from both phases to 140,000 b/d.

The Minnesota Pipeline has a capacity of 300,000 b/d and is connected to the Enbridge system at Clearbrook, Minnesota. It transports crude oil from Canada to Minnesota refineries owned by Flint Hills in Rosemount and Marathon Oil in St. Paul. In 2008, a new pipeline - the MinnCan project, was built along most of the original Minnesota Pipeline route to bring additional crude oil supply from Canada to these refineries. The MinnCan project has a capacity of 165,000 b/d but can be expanded up to 350,000 b/d.

Downstream of Superior, Wisconsin, Enbridge has a capacity of 1.8 million b/d including 400,000 b/d of capacity added in 2009 via the Southern Access pipeline, which terminates at Flanagan, Illinois. Since Spearhead South and Spearhead North provide the only connections to Southern Access, the takeaway capacity of these two pipelines currently acts as a constraint. Spearhead South delivers light and heavy crude oil to Cushing, Oklahoma. It was expanded in May 2009 by 65,000 b/d to a capacity of 190,000 b/d. Spearhead North capacity is currently idled as Enbridge seeks to optimize its pipeline operations at a time of surplus capacity.

Enbridge Alberta Clipper ①

The Alberta Clipper pipeline is an expansion of the Enbridge existing mainline system and extends from Hardisty, Alberta to Superior, Wisconsin with a connection to the Minnesota Pipeline at Clearbrook. The initial capacity of 450,000 b/d of heavy crude oil can be further expanded to 800,000 b/d. The pipeline began linefill in April 2010 which is expected to be completed by October.

Kinder Morgan Trans Mountain Pipeline

The Trans Mountain system originates in Edmonton, Alberta and transports crude oil to the Vancouver area, including the Westridge dock for vessel or barge loadings, and to a pipeline that provides deliveries to refineries in Washington State.

The pipeline can currently transport about 300,000 b/d assuming 20 percent of the volumes are heavy crude oil. The actual available capacity varies depending on the amount of heavy crude oil transported. Currently, about 25 percent of the volumes shipped are heavy crude oil.

Trans Mountain is currently operating as a common carrier pipeline where shippers nominate for space on the pipeline without a contract. Under this system, if demand for services exceed pipeline capacity, all shipper requests for services are prorated, a process called apportionment. Kinder Morgan is proposing to offer up to 50,000 b/d of firm service for deliveries to the Westridge dock. Shippers with firm contracts would not be subject to apportionment.

Kinder Morgan Express-Platte Pipelines

The Express Pipeline ships crude oil from Hardisty, Alberta to PADD IV and has a capacity of 280,000 b/d. The pipeline is underpinned by 231,000 b/d of firm contracts, many of which expire in 2012. The remaining space being available for spot or "common carriage" shippers.

The Platte system connects to Express at Casper, Wyoming and extends to Guernsey, Wyoming then to Wood River, Illinois. Capacity from Guernsey to Wood River is about 145,000 b/d and because of strong demand, the pipeline has been operating under apportionment since January 2007. Therefore, Express does not operate at capacity due to downstream constraints on the Platte system.

TransCanada Keystone ②

The Keystone Pipeline, which has an initial capacity of 435,000 b/d, runs from Hardisty, Alberta to the terminals in Wood River and Patoka, Illinois. The pipeline is scheduled to be in service by July 2010.

4.2 Oil Pipelines to the U.S. Midwest

The U.S. Midwest is the largest primary market for western Canadian crude oil. The two major market hubs from which crude oil is further distributed, are found at Wood River/ Patoka in Illinois and at Cushing, Oklahoma. Once all approved projects are in service, there will be excess capacity to these markets (Figure 4.2).

Currently, access to these hubs is constrained by the capacity of the Platte system and capacity from the Enbridge system on Spearhead South and the Mustang pipeline. The Mustang pipeline has a heavy crude oil capacity of about 91,000 b/d, of which 88,000 b/d is committed capacity. Current pipeline constraints to these hubs will be alleviated as new projects, such as the Keystone Pipeline and Cushing Extension go into service (Table 4.2).

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

Pipeline	Originating Point	End Point	Status	Capacity (thousand b/d)
Kinder Morgan Express-Platte	Guernsey, WY	Wood River, IL	Operating	145
Enbridge Spearhead	Flanagan, IL	Cushing, OK	Operating	190
ExxonMobil Mustang	Lockport, IL	Patoka, IL	Operating	91
TransCanada Keystone	Hardisty, AB	Patoka, IL	Linefill	435
TransCanada Keystone Extension	KS/NE border	Cushing, OK	Approved - for 2011	155

TransCanada Keystone and Cushing Extension

By the end of the year, the TransCanada Keystone Pipeline will provide an additional 435,000 b/d of capacity into Wood River/Patoka. Shortly thereafter, the Keystone system will be extended to Cushing, Oklahoma from the Nebraska/Kansas border, adding 155,000 b/d of capacity in 2011. Subsequently, the combined capacity from Hardisty, Alberta to either the Wood River/Patoka or Cushing markets would be 590,000 b/d.

4.3 Oil Pipelines to the U.S. Gulf Coast

Western Canadian crude oil currently has limited access to the U.S. Gulf Coast market through a small amount of capacity on the Pegasus Pipeline and spot vessel movements from the Trans Mountain Westridge dock. (Figure 4.2). However, the planned Keystone XL Pipeline in 2013, would alleviate pipeline constraints to this market for several years (Table 4.3).

ExxonMobil Pegasus Pipeline

In June 2009, the Pegasus Pipeline was expanded by 30,000 b/d to its current capacity of 96,000 b/d. This pipeline currently provides western Canadian crude oil producers with the only pipeline access to the U.S. Gulf Coast.

Figure 4.2 Canadian & U.S. Crude Oil Pipelines - All Proposals

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

Pipeline	Originating Point	End Point	Status	Capacity (thousand b/d)
ExxonMobil Pegasus	Patoka, IL	Nederland, TX	Operating	96
TransCanada Keystone XL	Hardisty, AB	NE/KS border	Approved - for 2013	700
TransCanada Keystone XL - Cushing to Gulf Coast portion	Cushing, OK	U.S. Gulf Coast	Approved - for 2013 but 2012 possble	
TransCanada Louisiana Access Option #1	Patoka, IL	New Orleans, LA	Proposed	
TransCanada Louisiana Access Option #2	Port Arthur, TX	New Orleans, LA	Proposed	

TransCanada Keystone XL and Louisiana Access options 3

TransCanada received approval for the Canadian portion of the Keystone XL project in March 2010 and has targetted the pipeline to be in service by 2013. There is a possibility for access to the Gulf Coast to be available as early as 2012 by building the Cushing to U.S. Gulf Coast portion of the pipeline project first.

This pipeline would originate at Hardisty, Alberta and then connect to the Cushing Extension at the Nebraska/Kansas border and then to Port Arthur and Houston, Texas. The initial pipeline capacity would be 700,000 b/d; of which 380,000 b/d has been secured by long-term contracts. The pipeline could be further expanded to 1.5 million b/d.

Additional options being considered include access to Louisiana by either building new or using existing facilities from Patoka to New Orleans or building a new line from Port Arthur, Texas to New Orleans. Proposed project timing is uncertain due to the early stages of these proposals.

4.4 Oil Pipelines to the West Coast

The Trans Mountain Pipeline is currently the only pipeline route to markets off the West Coast. The dark blue lines on the map in Figure 4.2 show the existing and proposed pipelines going to the West Coast.

Kinder Morgan TMX2, TMX3 and Northern Leg Expansion 5 6

The TMX2 expansion could increase capacity by 80,000 b/d by 2015. The scope of TMX2 includes a new line from Edmonton, Alberta to Kamloops, British Columbia. TMX3 includes a new line to the Washington State refineries and a second berth at the Westridge dock. TMX3 could provide an additional 320,000 b/d of new capacity by 2016. These expansions would provide additional access to Vancouver, Washington State and other markets served by oil tankers and barges which load at its Westridge dock.

TMX Northern Leg is a pipeline with a capacity of 400,000 b/d, extending from its existing system near Rearguard, British Columbia to a deep water port facility at Kitimat, British Columbia that would accommodate Very Large Crude Carriers (VLCC) for delivery to PADD V or the Far East. Depending on regulatory approvals and industry support, the pipeline could be in service as early as 2015.

Enbridge Northern Gateway 4

The Northern Gateway Project includes the construction of a new 36-inch diameter pipeline from Edmonton, Alberta to a deep water port at Kitimat, British Columbia and is being designed to provide 525,000 b/d of crude oil export capacity. Crude oil would be loaded on tankers for delivery to PADD V and the Far East. Enbridge submitted an application to the National Energy Board at the end of May 2010.

Table 4.4 Summary of Crude Oil Pipelines to the West Coast

Pipeline	Originating Point	End Point	Status	Capacity (thousand b/d)
Enbridge Northern Gateway	Bruderheim, AB	Kitimat, BC	Proposed	525
Kinder Morgan TMX2	Edmonton, AB	Kamloops, BC	Proposed	80
Kinder Morgan TMX3	Kamloops, BC	Sumas, BC	Proposed	320
Kinder Morgan TMX Northern Leg	Rearguard/ Edmonton, AB	Kitimat, BC	Proposed	400

4.5 Other Proposals

Canadian National (CN) Railways and Altex are jointly exploring a "Pipeline on Rail" strategy. This proposal could transport as little as 10,000 to 20,000 b/d of undiluted or under-diluted bitumen in heated railcars. Through connections to other railroads, CN can access the majority of U.S. Gulf Coast refineries. This rail solution would also be suitable for condensate imports. CN has indicated that if there was interest, there would be no upper limit to the volumes that could be transported via rail.

4.6 Diluent Pipelines

The diluent pipeline projects were developed in response to demand by western Canadian heavy crude oil producers for additional diluent supply in order to transport growing volumes of bitumen production.

Enbridge Southern Lights

The Southern Lights pipeline project includes a new diluent line which flows from Flanagan, Illinois (near Chicago) to Clearbrook, Minnesota, and the reversal of Enbridge's existing Line 13 from Clearbrook to Edmonton, Alberta.

The initial capacity of the diluent import line is 180,000 b/d, of which 77,000 b/d is for committed shippers. It can be expanded to 330,000 b/d with minor looping and to over 400,000 b/d with full looping. The in service date for the pipeline is July 2010.

Joint Capline/Chicap Industry Initiative

The owners of both Chicap and Capline are co-operating to enable the movement of a limited amount of diluent from the U.S. Gulf Coast to Chicago by mid 2010. The plan is for the Chicap Pipeline to connect to the Enbridge Southern Lights Pipeline. Chicap runs from Patoka, Illinois to the Chicago market. Ultimate capacity on the pipeline is estimated to be 320,000 b/d operating in batched diluent and light crude oil service. Initial total capacity of the pipeline in 2010 will be about 50 percent of the ultimate capacity. Capline extends from St. James, Louisiana to Patoka and has a capacity of more than one million b/d. The level of diluent deliveries is not known at this time

Enbridge Northern Gateway Diluent

As part of its Northern Gateway crude oil pipeline project, Enbridge is proposing a 193,000 b/d diluent import pipeline that would extend from Kitimat, British Columbia to Edmonton, Alberta. An application to the National Energy Board was filed at the end of May 2010.

4.7 Pipeline Summary

In 2010, 885,000 b/d of new pipeline capacity exiting the Western Canada Sedimentary Basin was added and another 855,000 b/d has been approved that could go into service over the next few years. In addition, there are other projects being proposed that could add additional capacity. These pipeline projects will provide producers with increased access to traditional markets as well as access to the Gulf Coast and offshore West Coast markets. Such market diversity is important for producers who are investing large amounts of capital in order to grow crude oil production. The timing of the approved projects going into service, however, will mean that excess pipeline capacity out of the basin will exist until around 2022, when growth in crude oil supply is expected to reach over four million b/d.

GLOSSARY

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

Oil	Condensate, crude oil, or a constituent of raw gas, condensate, or crude oil that is recovered in processing and is liquid at the conditions under which its volume is measured or estimated.
Oil sands	Refers to a mixture of sand and other rock materials containing crude bitumen or the crude bitumen contained in those sands.
Oil Sands Deposit	A natural reservoir containing or appearing to contain an accumulation of oil sands separated or appearing to be separated from any other such accumulation. The ERCB has designated three areas in Alberta as oil sands areas.
Pentanes Plus	A mixture mainly of pentanes and heavier hydrocarbons that ordinarily may contain some butanes and is obtained from the processing of raw gas, condensate or crude oil.
PADD	Petroleum Administration for Defense District that defines a market area for crude oil in the U.S.
Refined Petroleum Products	End products in the refining process (e.g. gasoline).
Specification	Defined properties of a crude oil or refined petroleum product.
SynBit	A blend of bitumen and synthetic crude oil that has similar properties to medium sour crude oil.
Upgrading	The process that converts bitumen or heavy crude oil into a product with a lower density and viscosity.
West Texas Intermediate	WTI is a light sweet crude oil, produced in the United States, which is the benchmark grade of crude oil for North American price quotations.

APPENDIX A
ACRONYMS, ABBREVIATIONS, UNITS AND CONVERSION FACTORS

Acronyms

API	American Petroleum Institute
CAPP	Canadian Association of Petroleum Producers
CSS	Cyclic Steam Stimulation
DRA	Drag Reducing Agent
EIA	Energy Information Administration
ERCB	(Alberta) Energy & Resources Conservation Board
IEA	International Energy Agency
PADD	Petroleum Administration for Defense District
S	sulphur
SAGD	Steam Assisted Gravity Drainage
U.S.	United States
WCSB	Western Canada Sedimentary Basin
WTI	West Texas Intermediate

Canadian Provincial Abbreviations

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

Units

b/d	barrels per day

Conversion Factor

1 cubic metre = 6.293 barrels (oil)

U.S. State Abbreviations

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

APPENDIX B.1

CAPP Canadian Crude Oil Production Forecast 2010 – 2025

Growth
June 2010

thousand barrels per day					*Actuals*	*Forecast*															
CONVENTIONAL	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Light & Medium																					
Alberta	374	360	347	347	316	304	294	284	276	268	260	252	245	237	230	225	221	217	212	208	204
B.C.	30	29	26	23	22	20	19	18	17	16	16	15	14	13	13	12	11	11	10	10	9
Saskatchewan [1,2]	148	155	162	183	184	185	185	185	185	185	181	177	174	169	164	158	154	149	145	140	135
Manitoba	14	19	22	23	26	27	27	27	26	26	25	25	24	24	23	23	22	22	21	21	21
N.W.T.	19	19	18	16	16	15	14	13	12	12	11	11	10	10	9	9	8	8	7	7	7
Total Conv. Light and Medium	**585**	**581**	**575**	**593**	**563**	**550**	**538**	**527**	**517**	**507**	**493**	**479**	**467**	**453**	**439**	**427**	**417**	**407**	**396**	**385**	**375**
Heavy																					
Alberta Conv. Heavy	197	183	178	156	145	138	131	124	118	112	107	101	96	91	87	82	78	74	71	67	64
Saskatchewan Conv. Heavy [1,2]	271	273	264	255	237	228	217	211	208	203	199	195	191	188	184	180	177	173	170	166	163
Total Conventional Heavy	**468**	**456**	**442**	**411**	**382**	**366**	**348**	**335**	**326**	**316**	**306**	**296**	**288**	**279**	**271**	**262**	**255**	**247**	**240**	**233**	**227**
TOTAL CONVENTIONAL	**1,053**	**1,037**	**1,017**	**1,004**	**946**	**916**	**886**	**862**	**843**	**822**	**799**	**775**	**755**	**732**	**710**	**689**	**672**	**654**	**637**	**618**	**602**
PENTANES/CONDENSATE	**160**	**166**	**173**	**169**	**161**	**157**	**154**	**151**	**148**	**145**	**142**	**141**	**140**	**138**	**137**	**135**	**134**	**133**	**131**	**130**	**129**
OIL SANDS (BITUMEN & UPGRADED CRUDE OIL)																					
Oil Sands Mining	534	623	647	610	690	767	856	924	1,015	1,043	1,056	1,070	1,079	1,111	1,159	1,229	1,277	1,327	1,436	1,514	1,529
Oil Sands *In Situ*	439	494	536	584	657	716	793	888	952	1,022	1,106	1,221	1,311	1,442	1,551	1,640	1,724	1,772	1,830	1,891	1,931
TOTAL OIL SANDS	**972**	**1,117**	**1,183**	**1,193**	**1,348**	**1,483**	**1,650**	**1,813**	**1,966**	**2,064**	**2,162**	**2,291**	**2,390**	**2,553**	**2,710**	**2,868**	**3,000**	**3,099**	**3,266**	**3,405**	**3,461**
WESTERN CANADA OIL PRODUCTION	**2,185**	**2,319**	**2,373**	**2,366**	**2,454**	**2,556**	**2,690**	**2,826**	**2,957**	**3,032**	**3,104**	**3,207**	**3,284**	**3,422**	**3,556**	**3,692**	**3,806**	**3,886**	**4,034**	**4,153**	**4,191**
ATLANTIC CANADA OIL PRODUCTION	**304**	**304**	**369**	**342**	**268**	**250**	**265**	**240**	**220**	**195**	**190**	**175**	**225**	**255**	**225**	**190**	**190**	**180**	**170**	**155**	**145**
TOTAL CANADIAN OIL PRODUCTION	**2,489**	**2,623**	**2,742**	**2,709**	**2,722**	**2,806**	**2,955**	**3,066**	**3,177**	**3,227**	**3,294**	**3,382**	**3,509**	**3,677**	**3,781**	**3,882**	**3,996**	**4,066**	**4,204**	**4,308**	**4,336**
OIL SANDS RAW BITUMEN**																					
Oil Sands Mining	626	769	784	724	825	912	1,008	1,079	1,172	1,204	1,217	1,233	1,287	1,373	1,436	1,518	1,572	1,626	1,735	1,814	1,830
Oil Sands *In Situ*	439	494	536	584	665	721	805	901	964	1,034	1,119	1,235	1,328	1,461	1,574	1,665	1,750	1,798	1,857	1,918	1,958
TOTAL OIL SANDS	**1,065**	**1,263**	**1,320**	**1,307**	**1,490**	**1,632**	**1,813**	**1,980**	**2,137**	**2,238**	**2,336**	**2,468**	**2,615**	**2,834**	**3,010**	**3,183**	**3,322**	**3,424**	**3,592**	**3,732**	**3,788**

Notes:

1. *CAPP allocates Saskatchewan Area III Medium crude as heavy crude. Also 17% of Area IV is > 900 kg/m³.*
2. *CAPP has revised from the June 2007 report historical light/heavy ratio for Saskatchewan starting in 2005.*

*** Raw bitumen numbers are highlighted. The oil sands production numbers (as historically published) are a combination of upgraded crude oil and bitumen and therefore incorporate yield losses from integrated upgrader projects. Production from off-site upgrading projects are included in the production numbers as bitumen.*

APPENDIX B.2

CAPP Canadian Crude Oil Production Forecast 2010 – 2025

Operating & In Construction
June 2010

thousand barrels per day					Actuals	Forecast															
CONVENTIONAL	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Light & Medium																					
Alberta	374	360	347	347	316	304	294	284	276	268	260	252	245	237	230	225	221	217	212	208	204
B.C.	30	29	26	23	22	20	19	18	17	16	16	15	14	13	13	12	11	11	10	10	9
Saskatchewan [1,2]	148	155	162	183	184	185	185	185	185	185	181	177	174	169	164	158	154	149	145	140	135
Manitoba	14	19	22	23	26	27	27	27	26	26	25	25	24	24	23	23	22	22	21	21	21
N.W.T.	19	19	18	16	16	15	14	13	12	12	11	11	10	10	9	9	8	8	7	7	7
Total Conv. Light and Medium	**585**	**581**	**575**	**593**	**563**	**550**	**538**	**527**	**517**	**507**	**493**	**479**	**467**	**453**	**439**	**427**	**417**	**407**	**396**	**385**	**375**
Heavy																					
Alberta Conv. Heavy	197	183	178	156	145	138	131	124	118	112	107	101	96	91	87	82	78	74	71	67	64
Saskatchewan Conv. Heavy [1,2]	271	273	264	255	237	228	217	211	208	203	199	195	191	188	184	180	177	173	170	166	163
Total Conventional Heavy	**468**	**456**	**442**	**411**	**382**	**366**	**348**	**335**	**326**	**316**	**306**	**296**	**288**	**279**	**271**	**262**	**255**	**247**	**240**	**233**	**227**
TOTAL CONVENTIONAL	**1,053**	**1,037**	**1,017**	**1,004**	**946**	**916**	**886**	**862**	**843**	**822**	**799**	**775**	**755**	**732**	**710**	**689**	**672**	**654**	**637**	**618**	**602**
PENTANES/CONDENSATE	**160**	**166**	**173**	**169**	**161**	**157**	**154**	**151**	**148**	**145**	**142**	**141**	**140**	**138**	**137**	**135**	**134**	**133**	**131**	**130**	**129**
OIL SANDS (BITUMEN & UPGRADED CRUDE OIL)																					
Oil Sands Mining	534	623	647	610	690	767	856	924	1,015	1,039	1,051	1,063	1,068	1,068	1,068	1,068	1,068	1,068	1,068	1,068	1,068
Oil Sands *In Situ*	439	494	536	584	657	716	793	888	945	984	1,020	1,069	1,070	1,077	1,086	1,079	1,071	1,064	1,055	1,047	1,032
TOTAL OIL SANDS	**972**	**1,117**	**1,183**	**1,193**	**1,348**	**1,483**	**1,650**	**1,812**	**1,959**	**2,024**	**2,071**	**2,131**	**2,137**	**2,144**	**2,153**	**2,147**	**2,138**	**2,131**	**2,122**	**2,114**	**2,100**
WESTERN CANADA OIL PRODUCTION	**2,185**	**2,319**	**2,373**	**2,366**	**2,454**	**2,556**	**2,690**	**2,825**	**2,950**	**2,991**	**3,012**	**3,047**	**3,032**	**3,014**	**3,000**	**2,970**	**2,944**	**2,918**	**2,890**	**2,862**	**2,830**
ATLANTIC CANADA OIL PRODUCTION	**304**	**304**	**369**	**342**	**268**	**250**	**265**	**240**	**220**	**195**	**190**	**175**	**225**	**255**	**225**	**190**	**190**	**180**	**170**	**155**	**145**
TOTAL CANADIAN OIL PRODUCTION	**2,489**	**2,623**	**2,742**	**2,709**	**2,722**	**2,806**	**2,955**	**3,065**	**3,170**	**3,186**	**3,202**	**3,222**	**3,257**	**3,269**	**3,225**	**3,160**	**3,134**	**3,098**	**3,060**	**3,017**	**2,975**
OIL SANDS RAW BITUMEN**																					
Oil Sands Mining	626	769	784	724	825	912	1,008	1,079	1,172	1,200	1,212	1,223	1,228	1,228	1,228	1,228	1,228	1,228	1,228	1,228	1,228
Oil Sands *In Situ*	439	494	536	584	665	721	805	900	957	997	1,032	1,081	1,083	1,090	1,098	1,092	1,083	1,077	1,067	1,059	1,045
TOTAL OIL SANDS	**1,065**	**1,263**	**1,320**	**1,307**	**1,490**	**1,632**	**1,813**	**1,979**	**2,130**	**2,197**	**2,244**	**2,304**	**2,311**	**2,318**	**2,326**	**2,320**	**2,311**	**2,305**	**2,295**	**2,287**	**2,273**

Notes:

1. *CAPP allocates Saskatchewan Area III Medium crude as heavy crude. Also 17% of Area IV is > 900 kg/m^3.*
2. *CAPP has revised from the June 2007 report historical light/heavy ratio for Saskatchewan starting in 2005.*

*** Raw bitumen numbers are highlighted. The oil sands production numbers (as historically published) are a combination of upgraded crude oil and bitumen and therefore incorporate yield losses from integrated upgrader projects. Production from off-site upgrading projects are included in the production numbers as bitumen.*

APPENDIX B.3

CAPP Western Canadian Crude Oil Supply Forecast 2010 – 2025

Growth
June 2010

Blended Supply to Trunk Pipelines and Markets

thousand barrels per day					***Actuals***	*Forecast*															
CONVENTIONAL	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Total Light and Medium	581	577	571	589	559	546	534	523	513	503	489	475	463	449	435	423	413	403	392	381	371
Net Conventional Heavy to Market	405	386	382	350	311	288	268	254	243	232	221	210	201	191	182	172	165	156	148	140	133
TOTAL CONVENTIONAL	**985**	**963**	**954**	**939**	**870**	**834**	**802**	**777**	**756**	**735**	**710**	**685**	**664**	**640**	**617**	**595**	**578**	**559**	**541**	**521**	**505**
OIL SANDS																					
Upgraded Light (Synthetic)[1]	506	572	622	556	653	745	836	883	882	878	896	900	947	994	996	1,014	1,143	1,176	1,209	1,225	1,206
Bitumen Blend [2]	686	795	834	937	970	986	1,118	1,251	1,444	1,564	1,669	1,820	1,848	1,941	2,112	2,202	2,269	2,365	2,566	2,735	2,818
TOTAL OIL SANDS AND UPGRADERS	**1,192**	**1,368**	**1,455**	**1,493**	**1,622**	**1,731**	**1,953**	**2,134**	**2,326**	**2,442**	**2,565**	**2,720**	**2,795**	**2,935**	**3,108**	**3,216**	**3,412**	**3,542**	**3,775**	**3,961**	**4,024**
Total Light Supply	1,087	1,149	1,193	1,145	1,212	1,292	1,370	1,406	1,395	1,381	1,385	1,375	1,410	1,443	1,430	1,437	1,556	1,579	1,602	1,607	1,577
Total Heavy Supply	1,091	1,182	1,216	1,287	1,281	1,274	1,385	1,505	1,687	1,796	1,890	2,030	2,049	2,133	2,294	2,374	2,434	2,521	2,714	2,875	2,951
WESTERN CANADA OIL SUPPLY	**2,178**	**2,331**	**2,409**	**2,432**	**2,493**	**2,565**	**2,755**	**2,911**	**3,082**	**3,177**	**3,275**	**3,405**	**3,459**	**3,575**	**3,725**	**3,811**	**3,990**	**4,101**	**4,315**	**4,482**	**4,528**

Notes:

1. *Includes upgraded conventional.*

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

APPENDIX B.4

CAPP Western Canadian Crude Oil Supply Forecast 2010 – 2025

Operating & In Construction
June 2010

Blended Supply to Trunk Pipelines and Markets

thousand barrels per day					*Actuals*	*Forecast*															
CONVENTIONAL	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Total Light and Medium	581	577	571	589	559	546	534	523	513	503	489	475	463	449	435	423	413	403	392	381	371
Net Conventional Heavy to Market	405	386	382	350	311	288	268	254	243	232	221	210	201	191	182	172	165	156	148	140	133
TOTAL CONVENTIONAL	**985**	**963**	**954**	**939**	**870**	**834**	**802**	**777**	**756**	**735**	**710**	**685**	**664**	**640**	**617**	**595**	**578**	**559**	**541**	**521**	**505**
OIL SANDS																					
Upgraded Light (Synthetic)[1]	506	572	622	556	653	745	836	883	889	910	940	922	920	916	910	916	924	929	936	942	955
Bitumen Blend [2]	686	795	834	937	970	986	1,118	1,250	1,430	1,491	1,521	1,598	1,607	1,617	1,632	1,619	1,602	1,590	1,572	1,558	1,530
TOTAL OIL SANDS AND UPGRADERS	**1,192**	**1,368**	**1,455**	**1,493**	**1,622**	**1,731**	**1,953**	**2,133**	**2,319**	**2,401**	**2,461**	**2,520**	**2,527**	**2,533**	**2,542**	**2,534**	**2,525**	**2,518**	**2,508**	**2,500**	**2,485**
Total Light Supply	1,087	1,149	1,193	1,145	1,212	1,292	1,370	1,406	1,402	1,413	1,429	1,397	1,383	1,364	1,345	1,338	1,337	1,331	1,329	1,323	1,326
Total Heavy Supply	1,091	1,182	1,216	1,287	1,281	1,274	1,385	1,504	1,674	1,723	1,742	1,808	1,808	1,809	1,814	1,791	1,766	1,746	1,720	1,698	1,663
WESTERN CANADA OIL SUPPLY	**2,178**	**2,331**	**2,409**	**2,432**	**2,493**	**2,565**	**2,755**	**2,910**	**3,075**	**3,136**	**3,171**	**3,205**	**3,190**	**3,173**	**3,158**	**3,129**	**3,103**	**3,077**	**3,049**	**3,021**	**2,989**

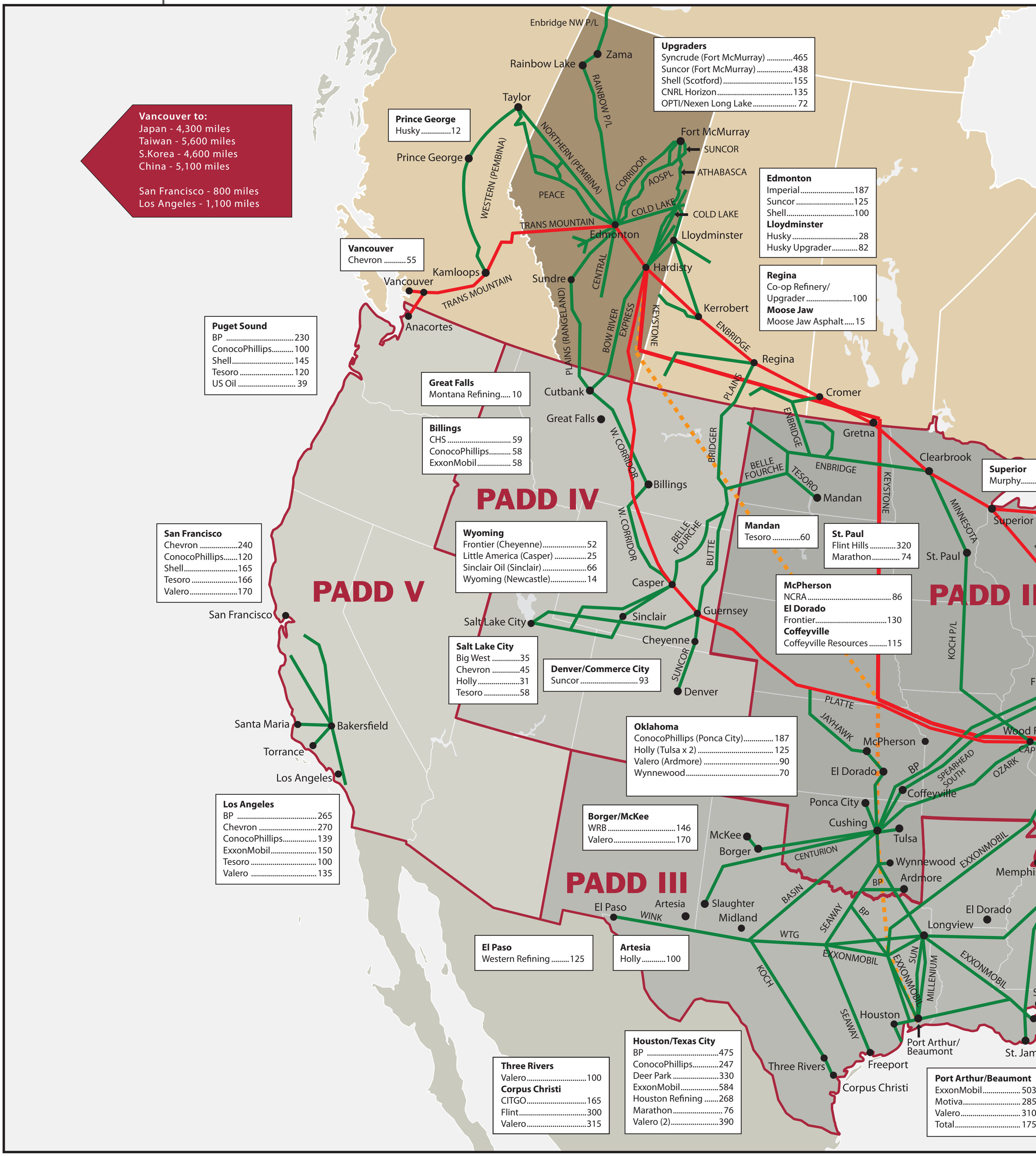
Notes:

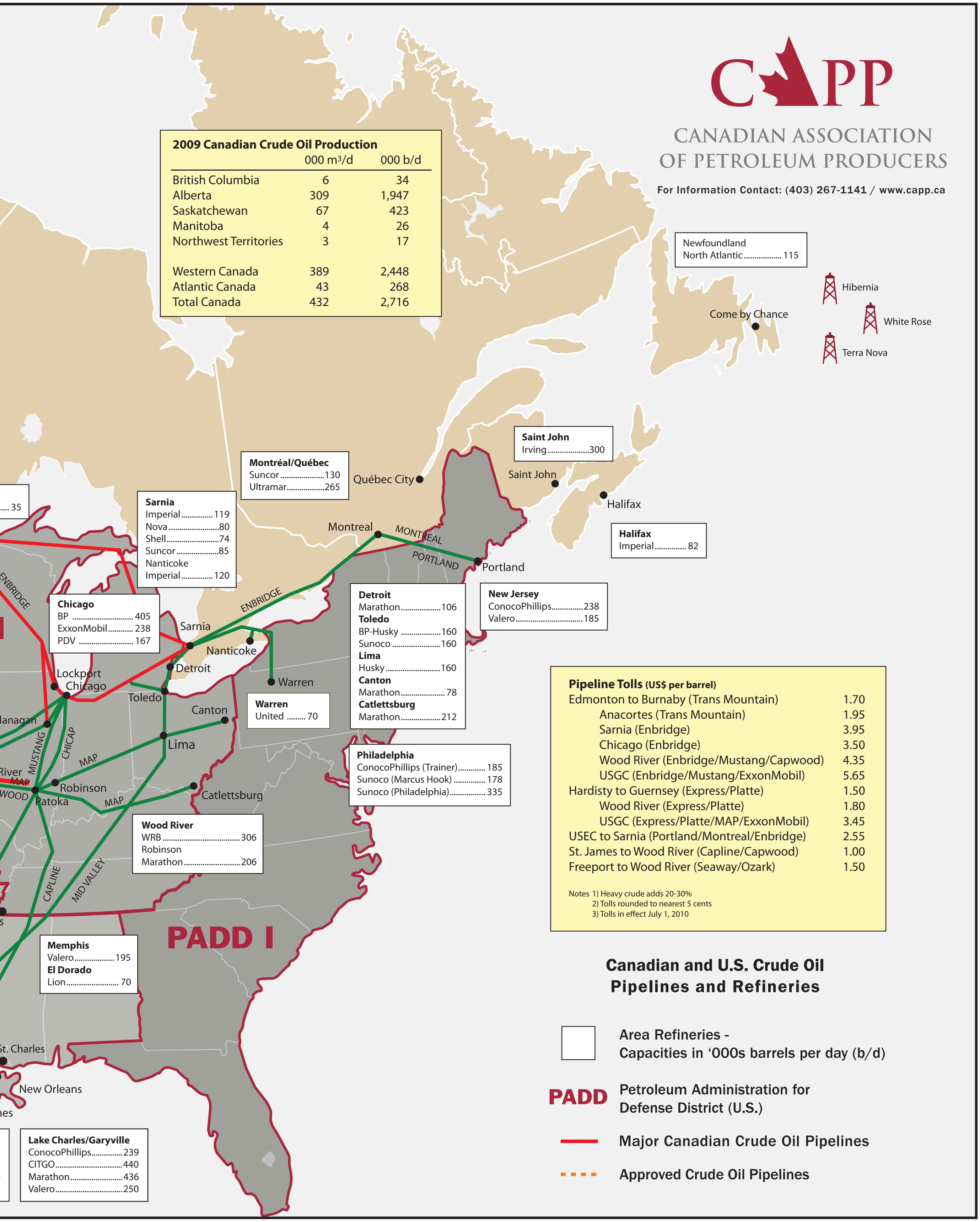
1. *Includes upgraded conventional.*

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

APPENDIX C

Crude Oil Pipelines and Refineries





2009 Canadian Crude Oil Production

	000 m³/d	000 b/d
British Columbia	6	34
Alberta	309	1,947
Saskatchewan	67	423
Manitoba	4	26
Northwest Territories	3	17
Western Canada	389	2,448
Atlantic Canada	43	268
Total Canada	432	2,716

Pipeline Tolls (US$ per barrel)

Edmonton to Burnaby (Trans Mountain)	1.70
Anacortes (Trans Mountain)	1.95
Sarnia (Enbridge)	3.95
Chicago (Enbridge)	3.50
Wood River (Enbridge/Mustang/Capwood)	4.35
USGC (Enbridge/Mustang/ExxonMobil)	5.65
Hardisty to Guernsey (Express/Platte)	1.50
Wood River (Express/Platte)	1.80
USGC (Express/Platte/MAP/ExxonMobil)	3.45
USEC to Sarnia (Portland/Montreal/Enbridge)	2.55
St. James to Wood River (Capline/Capwood)	1.00
Freeport to Wood River (Seaway/Ozark)	1.50

Notes 1) Heavy crude adds 20-30%
2) Tolls rounded to nearest 5 cents
3) Tolls in effect July 1, 2010

CAPP
CANADIAN ASSOCIATION
OF PETROLEUM PRODUCERS

The Canadian Association of Petroleum Producers (CAPP) represents companies, large and small, that explore for, develop and produce natural gas and crude oil throughout Canada. CAPP's member companies produce about 90 per cent of Canada's natural gas and crude oil. CAPP's associate members provide a wide range of services that support the upstream crude oil and natural gas industry. Together CAPP's members and associate members are an important part of a $110-billion-a-year national industry that provides essential energy products. CAPP's mission is to enhance the economic sustainability of the Canadian upstream petroleum industry in a safe and environmentally and socially responsible manner, through constructive engagement and communication with governments, the public and stakeholders in the communities in which we operate.

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