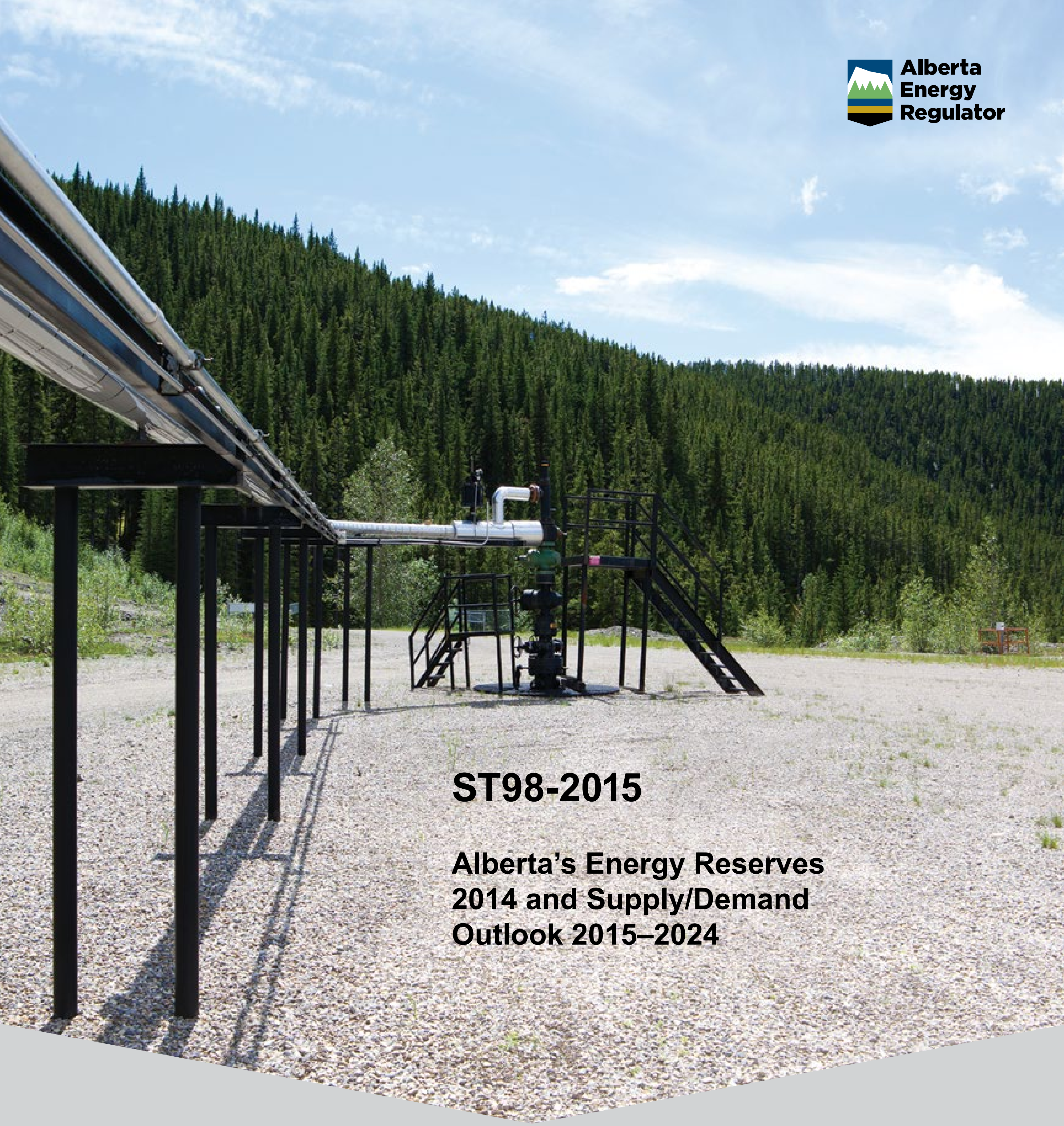

ST98-2015

Alberta's Energy Reserves 2014 and Supply/Demand Outlook 2015–2024

ST98

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ST98-2015 HIGHLIGHTS

Alberta's Energy Reserves 2014 and Supply/Demand Outlook 2015–2024

ECONOMICS

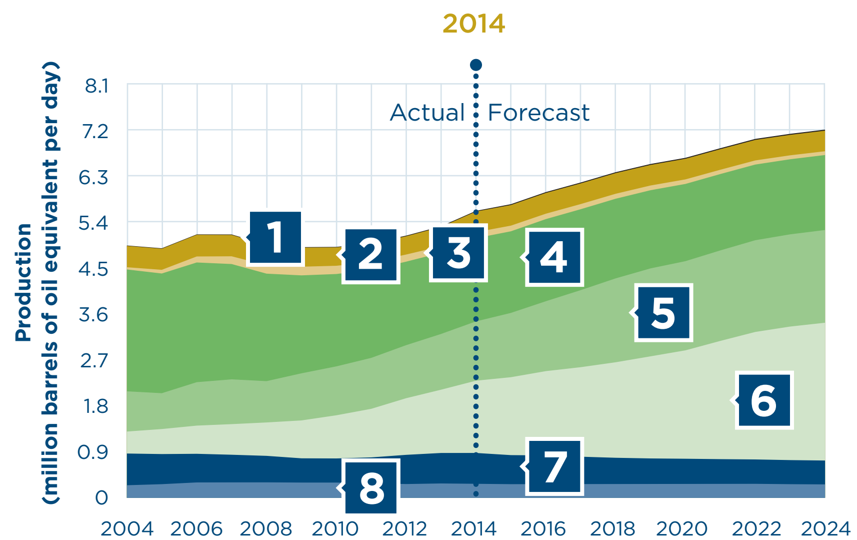
Natural gas prices
ARP
↑ 41%
(Cdn \$4.00/GJ)
Compared with 2013

Oil prices
WTI
↓ 5%
(US \$93.00/bbl)
Compared with 2013

Value of Production in Alberta

2013	2014
95.4 B Cdn\$	110.8 B Cdn\$

FORECASTING



1 Hydro, wind, and other renewables
2 Natural gas liquids
3 Unconventional natural gas
4 Conventional natural gas
5 Mined bitumen
6 In situ bitumen
7 Conventional crude oil
8 Coal

NATURAL GAS

Remaining reserves	Wells placed on production	Marketable gas production
↓ 4% ($913\ 10^9\ m^3$)	↑ 32% (1682)	↑ 2% ($287\ 10^6\ m^3/d$)
Compared with 2013	Compared with 2013	Compared with 2013

NATURAL GAS LIQUIDS

In 2014

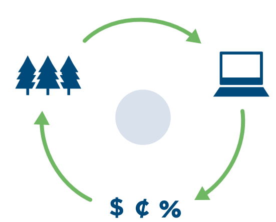
Ethane
-4% reserves ($107\ 10^6\ m^3$)
-2% production ($36\ 10^3\ m^3/d$)

Propane
-2% reserves ($64\ 10^6\ m^3$)
+1% production ($24\ 10^3\ m^3/d$)

Butanes
-2% reserves ($35\ 10^6\ m^3$)
+2% production ($13\ 10^3\ m^3/d$)

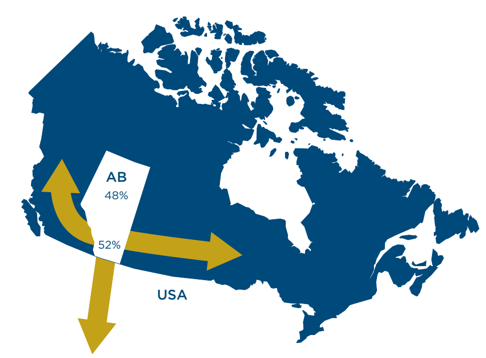
Pentanes plus
-5% reserves ($43\ 10^6\ m^3$)
+20% production ($25\ 10^3\ m^3/d$)

RESOURCE ENDOWMENT

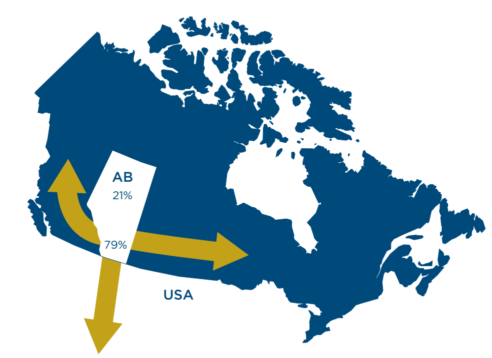


The AER regulates all aspects of the development of Alberta's abundant energy resources, including the environmental, technical, and economic aspects.

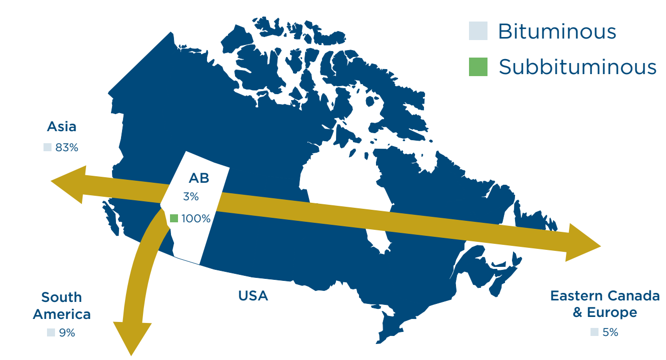
Deliveries of Gas



Deliveries of Crude Oil



Deliveries of Coal

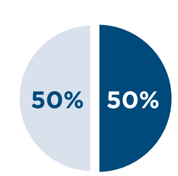


CRUDE OIL

Remaining reserves	Total crude production	Wells placed on production
↑ 2% ($288\ 10^6\ m^3$)	↑ 1% ($94\ 10^3\ m^3/d$)	↓ 7% (2577)

SULPHUR

Refinery & upgrading



Sour gas

Remaining reserves	Sulphur production
↓ 3% ($114\ 10^6$ t)	↓ 7% ($4\ 10^6$ t)

CRUDE BITUMEN

Remaining reserves	Mineable production	In situ production	Total bitumen production
↓ 1% ($26\ 10^9\ m^3$)	↑ 6% ($165\ 10^3\ m^3/d$)	↑ 14% ($201\ 10^3\ m^3/d$)	↑ 11% ($366\ 10^6\ m^3$)

COAL

Remaining reserves	Over 1000 years of supply	Total coal production
↔ Unchanged (33 Gt)		↑ 2% (30 Mt)

2014 HIGHLIGHTS

Acknowledgements

The following AER staff contributed to this report:

Principal Authors:

Reserves: Michael Teare, Shauna Miller, Sharleen Overland, and Rick Marsh

Supply/Demand and Economics: Charles Tamblyn, Mussie Yemane, Banafsheh Ashrafi, Afshan Mahmood, Glen Tsui, Shamus Hardie, and Afshin Honarvar

Editors: Andrea Willwerth, Afshin Honarvar, and Rick Marsh

Editorial Assistance: Carol Crowfoot, Kevin Parks, and Jim Jenkins

Data: Debbie Giles, Shirley McGuffin, Glen Tsui, Judy VanHorne, and members of the Energy Statistics Team

Production: Jennifer Wagner, Nicole Dunn, Kristie Bogle, Aaron Dalton, Tyla Willett, Ken Bonnett, Sarah Hamza, Karen Logan, Robert DeGrace, and Janet Grein

Communications Advisor: Jordan Fitzgerald

Coordinator: Andrea Willwerth

Additional Information

For general inquiries, contact the AER's Energy Statistics Team at EnergyStatistics@aer.ca.

For inquiries regarding reserves, contact Rick Marsh at 403-297-8218 or Michael Teare at 403-297-2597.

For inquiries regarding supply/demand, contact Afshin Honarvar at 403-297-8172 or Charles Tamblyn at 403-297-4406.

Report graphics, including any corresponding data sets, and Appendix E georeferenced TIFF images and GIS contour thickness shapefiles are available on the AER website, www.aer.ca.

The following are related documents available from the AER Order Fulfillment Team (telephone: 403-297-8311; when connected, press 2):

- Electronic data file with detailed data tables for crude oil and natural gas, as well as a PDF map of designated fields, oil sands areas, and development entities, $546
- Electronic data file with field and pool code conversion file, $459
- Electronic data file with gas pool reserves file (ASCII format), $3095
- Electronic data file with oil pool reserves file (ASCII format), $1834
- Map-90: Map of designated fields, oil sands areas, and development entities: 60 × 101 cm, $63; 33 × 54 cm, $29

Contents

APPENDICES

Tables

9 INFRASTRUCTURE

APPENDICES

B SUMMARY OF CRUDE BITUMEN, CONVENTIONAL CRUDE OIL, NATURAL GAS RESERVES, AND NATURAL GAS LIQUIDS

D DRILLING ACTIVITY IN ALBERTA

Figures

2 RESOURCE ENDOWMENT

3 CRUDE BITUMEN

4 CRUDE OIL

5 NATURAL GAS

6 NATURAL GAS LIQUIDS

F SUMMARY OF ALBERTA'S SHALE- AND SILTSTONE-HOSTED HYDROCARBON RESOURCE POTENTIAL

HIGHLIGHTS

About 86 per cent of crude oil wells and 64 per cent of natural gas wells placed on production in 2014 were horizontal wells.

Investment in oil and natural gas development is projected to decrease in 2015 due to low crude oil and natural gas prices; however, investment is expected to recover after 2015.

Pentanes plus production increased by 20 per cent in 2014 and surpassed heavy oil production for the first time in recent history in Alberta.

OVERVIEW

Providing credible information to everyone involved in the development of Alberta's resources—landowners, communities, industry, government, and interested parties—supports good decision-making and is a key service of the AER. Every year the AER issues a report providing stakeholders with independent and comprehensive information on the state of reserves, supply, and demand for Alberta's diverse energy resources: crude bitumen, crude oil, natural gas, natural gas liquids, sulphur, and coal. This year's report includes estimates of initial established reserves (recoverable quantities estimated to be in the ground before any production), remaining established reserves (recoverable quantities known to be left), and ultimate potential (recoverable quantities that have already been discovered plus those that have yet to be discovered). It also includes a 10-year supply and demand forecast for Alberta's energy resources from 2015 to 2024 (the forecast period). Additionally, this report notes historical trends on energy commodities so that supply and price relationships may be better understood.

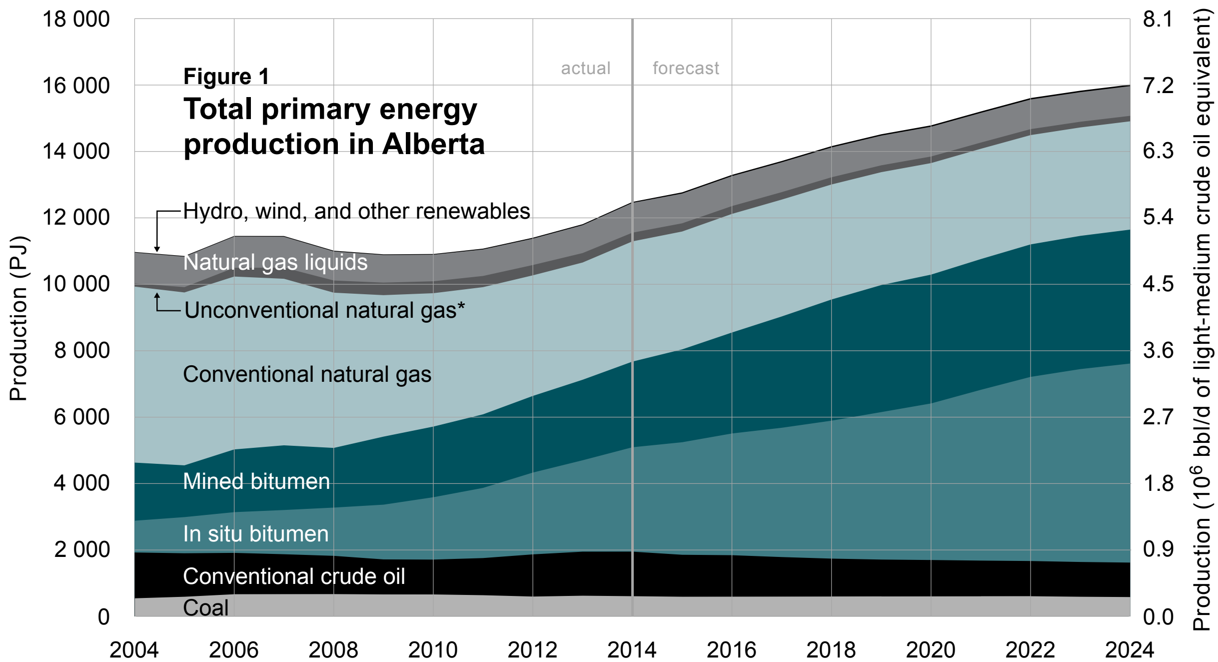
With natural gas and oil prices being 30 to 50 per cent lower early in 2015 than in 2014, the economic returns of oil and gas projects are expected to be affected. Investments in crude oil and natural gas exploration and development are projected to be more negatively affected than those in oil sands due to their shorter planning and development schedules. The oil sands projects under construction continue to move ahead, even though current oil prices do not appear to justify them. However, oil and gas prices are expected to recover in 2016. As the prices increase investment levels are anticipated to return to higher levels.

Summary of Energy Reserves, Production, and Demand in Alberta

In 2014, Alberta produced 12 518 petajoules (10^{15} joules) of energy from all sources, including renewable sources. This is equivalent to about 5.6 million barrels per day of conventional light-medium quality crude oil, a 5.8 per cent increase over 2013. In 2024, Alberta is projected to produce 16 012 petajoules of energy from all sources, which is equivalent to over 7.2 million barrels per day of conventional light-medium-quality crude oil. A breakdown of production by energy source is illustrated in **Figure 1**.

Reserves

Reserves are the recoverable quantities of energy resource commodities that are known with reasonable certainty. In-place resources are the larger quantities existing



*Includes coalbed methane and shale gas.

in the ground from which a portion has been, or may be, recovered as reserves. The AER also estimates a quantity (the ultimate potential) from discovered and undiscovered in-place resources that may be ultimately recovered when all future resource extraction activities have ceased within Alberta. The AER's current reserves and resource classification system is discussed in **Section 2.4**.

Table 1 summarizes Alberta's energy reserves, resources, and production at the end of 2014.

Energy Production

Raw bitumen in Alberta is produced either by mining the oil sands or by using various in situ techniques and wells to produce bitumen. In **Figure 1**, bitumen production accounted for 81 per cent of Alberta's total crude oil and bitumen production in 2014. Bitumen production increased by 6.4 per cent at mining projects and by 14.2 per cent at in situ projects in 2014, resulting in an overall raw bitumen production increase of 10.5 per cent over 2013.

In 2014, on an energy content basis (petajoules), crude oil production increased by about 1.2 per cent, total marketable natural gas production in Alberta increased by 2.3 per cent, total natural gas liquids (NGLs)[1] production increased by 6.8 per cent, and total coal production increased by about 1 per cent.[2]

---

1 Natural gas liquids refers to ethane, propane, butanes, and pentanes plus obtained from the processing of raw gas or condensate. See discussion in **Section 6**.

2 The trends and growth rates may differ slightly when standard units of measure, such as cubic metres or tonnes, are compared. Various grades of energy commodities have different heating values, and any changes to their mix may yield slightly different numerical trends and growth rates.

Table 1 Reserves, resources, and production summary, 2014

	Crude bitumen		Crude oil		Natural gas[a]		Raw coal	
	(million m^3)	(billion barrels)	(million m^3)	(billion barrels)	(billion m^3)	(trillion cubic feet)	(billion tonnes)	(billion tons)
Initial in-place resources	293 125	1 845	12 927	81.3	9 805	348	94	103
Initial established reserves	28 092	177	3 010	18.9	5 590	198	34.8	38.4
Cumulative production	1 661	10.4	2 722	17.1	4 677	166	1. 60	1.76
Remaining established reserves	**26 431**	**166**	**288**	**1.8**	**913**[b]	**32.4**[b]	**33.2**	**36.6**
Annual production	133.7	0.841	34.2	0.215	104.9[e]	3.7[e]	0.030[c]	0.033[c]
Ultimate potential (recoverable)	50 000	315	3 130	19.7	6 276[d]	223[d]	620	683

[a] Expressed as "as is" gas, except for annual production, which is 37.4 megajoules per cubic metre; includes coalbed methane.

[b] Measured at field gate.

[c] Annual production is marketable.

[d] Does not include unconventional natural gas.

[e] Includes unconventional natural gas.

While this report focuses on the fossil-based energy resources in the province, a relatively small amount of energy, about 0.2 per cent, is also produced from renewable energy sources, such as hydro and wind power.

Energy Demand

Alberta's primary energy demand by energy type is shown in **Figure 2**. In 2014, demand for all fossil-based energy commodities increased by 5.7 per cent relative to 2013. Demand for natural gas and pentanes plus is projected to increase throughout the forecast period in conjunction with the expected increase in crude bitumen production. Total primary energy consumption in 2014 was 4798 petajoules, equivalent to 2.1 million barrels per day of crude oil. This amount is projected to increase to about 6676 petajoules, or 3.0 million barrels per day, by 2024.

The primary energy removals from Alberta are shown in **Figure 3**. Most shipments are to the United States. Natural gas removals from Alberta are projected to decrease over the forecast period as Alberta loses market share in the eastern United States and central Canada due to U.S. shale gas production. Total primary energy removals from the province are expected to reach 10 378 petajoules in 2024, equivalent to 4.6 million barrels per day of crude oil, up from 7921 petajoules, or 3.5 million barrels per day, in 2014.

Alberta Hydrocarbon Production within the Canadian Context

Alberta is Canada's largest producer of marketable natural gas. In 2014, Alberta produced 67 per cent of Canada's total production, down from 69 per cent in 2013. Over the same period, Canada's second largest contributor,

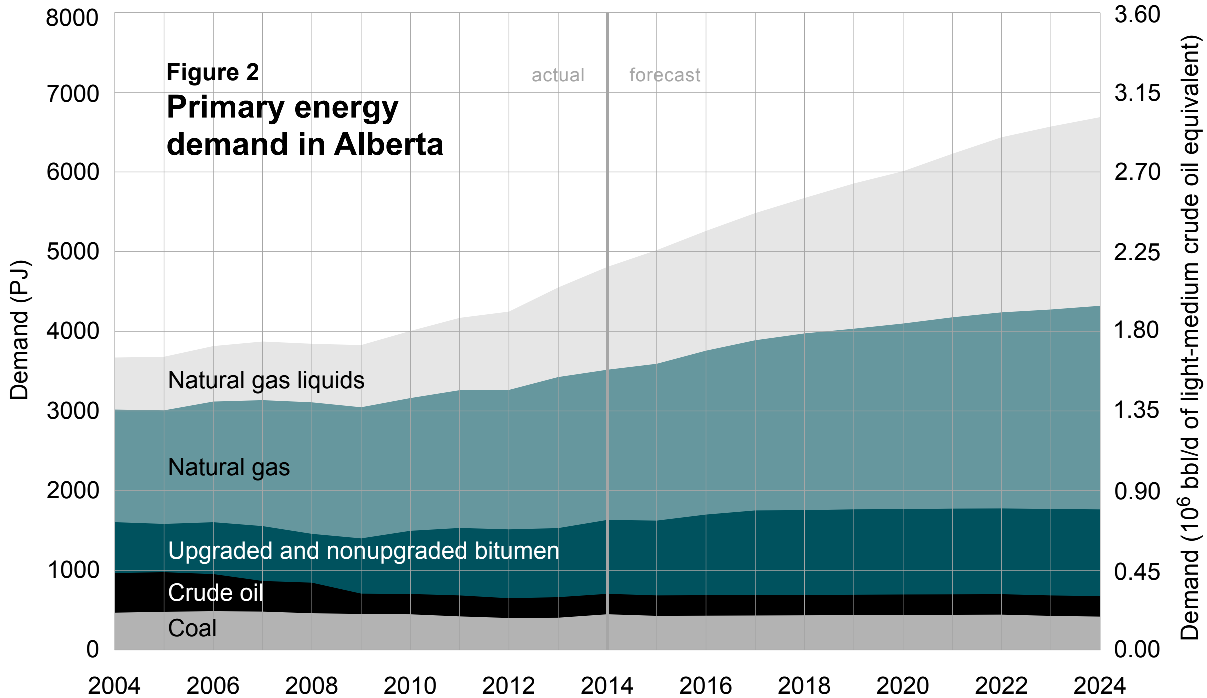


Figure 2
Primary energy demand in Alberta
actual
forecast
Natural gas liquids
Natural gas
Upgraded and nonupgraded bitumen
Crude oil
Coal
Demand (PJ)
Demand (10^6 bbl/d of light-medium crude oil equivalent)
8000
7000
6000
5000
4000
3000
2000
1000
0
3.60
3.15
2.70
2.25
1.80
1.35
0.90
0.45
0.00
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024

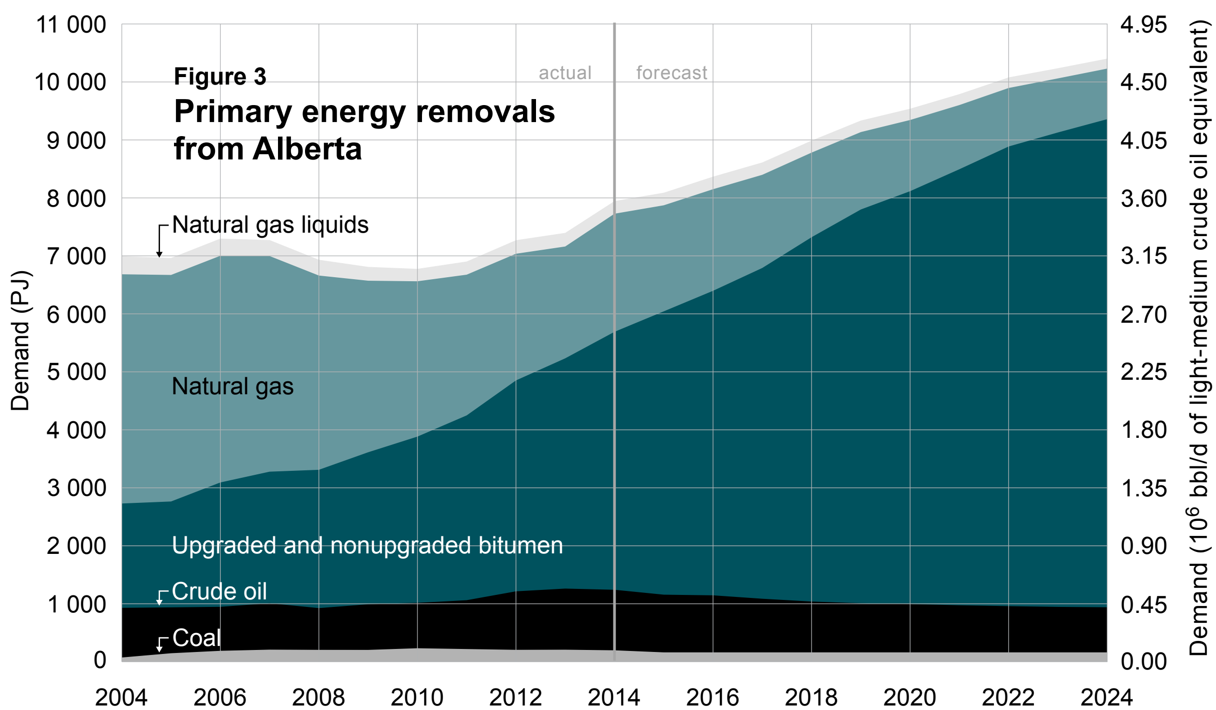


Figure 3
Primary energy removals from Alberta
actual
forecast
Natural gas liquids
Natural gas
Upgraded and nonupgraded bitumen
Crude oil
Coal
Demand (PJ)
Demand (10^6 bbl/d of light-medium crude oil equivalent)
11 000
10 000
9 000
8 000
7 000
6 000
5 000
4 000
3 000
2 000
1 000
0
4.95
4.50
4.05
3.60
3.15
2.70
2.25
1.80
1.35
0.90
0.45
0.00
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024

British Columbia, increased its share from 26 per cent to 27 per cent. **Figure 4** shows the percentage contributed by region in Canada for 2012, 2013, and 2014.

Alberta is also the largest contributor to Canadian oil and equivalent[3] production and is the only contributor of upgraded and nonupgraded bitumen, which are the marketed components of raw bitumen production. Only two provinces, Alberta and Saskatchewan, contribute to conventional heavy crude oil production in Canada. In 2014, Alberta accounted for 78 per cent of Canada's oil and equivalent production, with marketed bitumen representing 58 per cent of the total.

Figure 5 illustrates the contribution percentage breakdown by category and region in Canada for 2014.

Oil and Gas Prices and Alberta's Economy

Crude Oil Prices – 2014

In the first half of 2014, crude oil prices strengthened in response to modest global economic recovery and the continued tension in the Middle East and recent conflict between Ukraine and Russia. Prices began to fall in June 2014 and for the rest of the year, mainly due to

- weakening demand growth in Europe and China,
- increasing non-OPEC[4] production (particularly in North America), and
- OPEC's decision not to sacrifice its own market share to restore the price.

The price of Brent Blend (Brent)[5] started the year at a relatively high level and then fell during the second half of the year, averaging US$99.02 per barrel (bbl) in 2014, down 8.7 per cent from 2013. The price for West Texas Intermediate (WTI) light sweet crude oil averaged US$93.00/bbl in 2014, down 5.2 per cent from 2013.[6]

In 2014, the price differential between Brent and WTI ranged from US$3.05/bbl to US$13.26/bbl and averaged US$6.02/bbl. This discount reflects the significant increases in U.S. supplies and the lack of pipeline capacity to move crude oil from Cushing, Oklahoma, to the U.S. Gulf Coast. The differential narrowed in 2014, as recent pipeline additions and reversals and railroad infrastructure have partially alleviated the transportation constraints at Cushing, enabling crude oil to better reach refineries.

Heavier Canadian crudes, such as Western Canadian Select (WCS),[7] have shown deeper discounts compared with other world heavy crude oils. In 2014, WCS averaged US$71.77/bbl, trading at US$21.23/bbl below the price of

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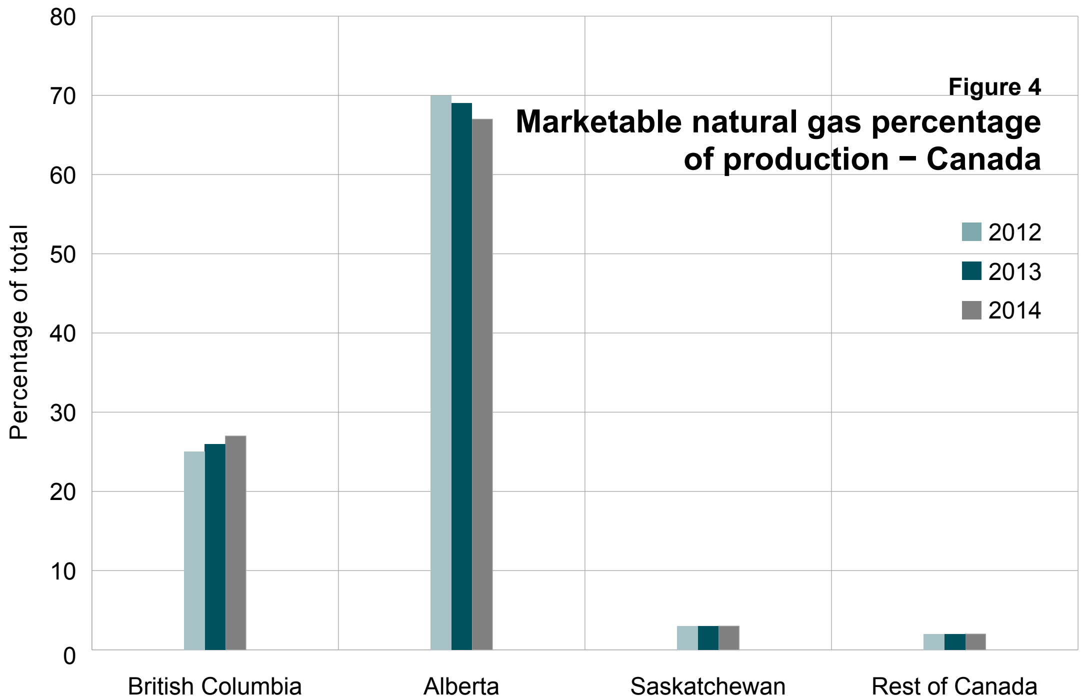
3 Oil and equivalent includes light-medium and heavy crude oil, condensate (pentanes plus), and upgraded and nonupgraded bitumen.

4 Organization of Petroleum Exporting Countries.

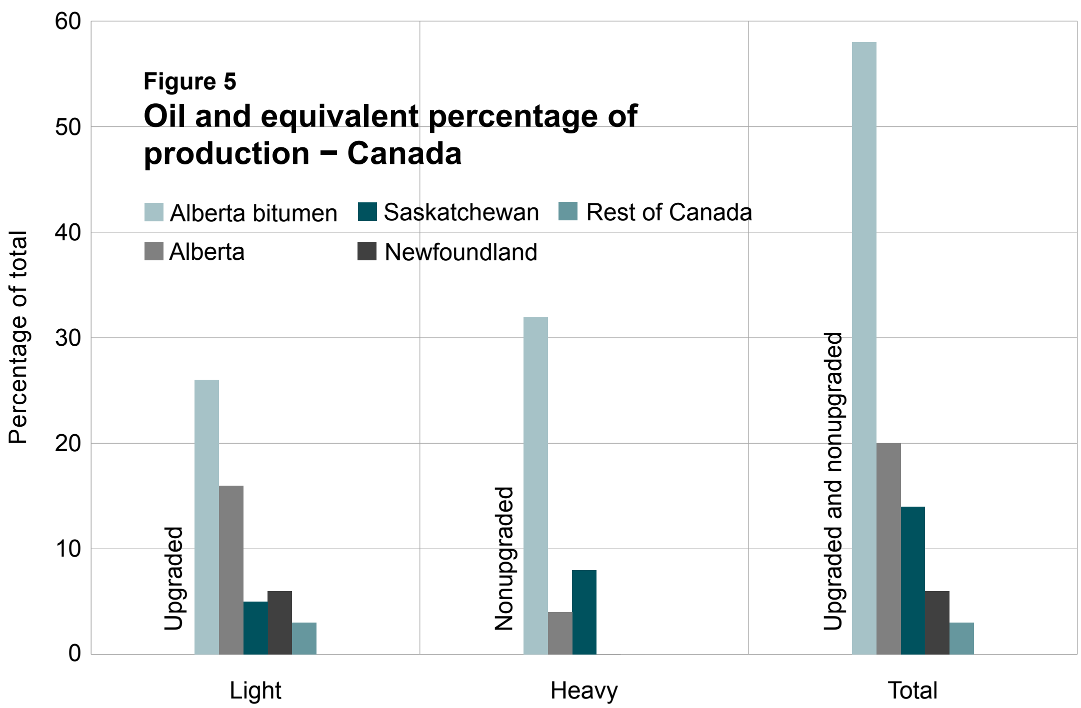
5 Brent is a light sweet crude oil from 15 different oil fields in the North Sea. Brent futures are traded on the Intercontinental Exchange Inc. and are considered a global benchmark for oil prices.

6 In this report, Brent spot prices and WTI near-month futures prices have been used.

7 Western Canadian Select is a type of marketed crude oil produced in western Canada and made up of heavy Canadian conventional crude oil and crude bitumen blended with diluent.



Source: National Energy Board.



Source: National Energy Board.

WTI, while Mexican Maya crude oil traded at an average US$7.19/bbl discount to WTI. Maya crude oil is close to WCS in quality, but is closer to heavy-oil-capable refineries in the Gulf Coast. Therefore, Canadian heavy crudes have been discounted due to the distance and transportation constraints to the heavy oil refineries in the U.S. Gulf Coast. Although the Canadian heavy crude discount relative to other heavy crudes is wide, the discount on heavy Canadian crudes has narrowed thanks to increased transportation capacity, moving more Canadian crude oil from Cushing to the U.S. Gulf Coast refineries. Adding more heavy refining capacity and alleviating pipeline constraints around Cushing will continue to improve the opportunity for Canadian heavy crude oils to be priced competitively with heavy crude oils from Mexico, Venezuela, and Columbia at the Gulf Coast.

Crude Oil Prices – Forecast

The AER bases its forecast on the expectation that the price of crude oil in North America, as measured by the price for WTI, will continue to be volatile in the short term. The AER projects WTI to average US$52.00/bbl in 2015, ranging from US$41.60/bbl to US$62.40/bbl. This is due to increased North American supply, historically high storage levels of crude oil, slow growth in world oil demand, and OPEC's strategy of defending the organization's market share by keeping oil production steady. The price of WTI is expected to increase throughout the forecast period as the pace of production slows down and oil storages return to normal levels. Longer term, projected crude oil demand exerts an upward pressure on supplies and price. In 2024, WTI prices are projected to be US$98.63/bbl.

Natural Gas Prices – 2014

While North American crude oil prices closely track international prices, natural gas prices in North America reflect domestic supply and demand. Alberta natural gas prices are heavily influenced by the market price at Henry Hub (near Erath, Louisiana) in the United States. The most significant market change over the past couple of years has been the increase in U.S. natural gas supply from shale gas, which became economic due to horizontal drilling and multistage fracturing completion technology. Natural gas producers in North America have been, and are expected to continue to be, challenged by a weak price environment as natural gas production continues to grow and new market access lags.

The average price of Alberta natural gas at the plant gate (Alberta reference price) in 2014 was Cdn$4.00 per gigajoule (GJ), compared with Cdn$2.83/GJ in 2013—a 41 per cent increase. In 2014, U.S. natural gas prices at Henry Hub also increased by 14.8 per cent over 2013. Natural gas prices in 2014 were affected by a cold winter across North America.

Natural Gas Prices – Forecast

The AER projects the Alberta natural gas reference price to average Cdn$2.83/GJ in 2015, ranging between Cdn$2.27/GJ and Cdn$3.40/GJ. In the near term, prices are projected to remain weak due to increasing gas supply in North America. Longer term, a combination of liquefied natural gas exports and increased domestic demand is expected to contribute to a strengthening of natural gas prices. Over the forecast period, the price of natural gas is projected to increase slowly, reaching Cdn$5.82/GJ in 2024.

Alberta's Economy – 2014

Alberta's real gross domestic product (GDP) growth has mostly outperformed Canadian real GDP growth over the past decade. Average Alberta GDP growth from 2004 to 2014 was 3.4 per cent, compared with a Canadian average of 2.0 per cent. Similarly, the unemployment rate in Alberta averaged 4.7 per cent over that period while the Canadian unemployment rate averaged 7.1 per cent.

In 2014, the total value of Alberta's energy resource production increased by 16 per cent over 2013. In 2014, combined upgraded and nonupgraded bitumen revenues (value of production) were about 50 per cent greater than the combined revenues from conventional gas, conventional crude oil, natural gas liquids, and sulphur. The AER estimates that oil sands capital expenditures increased to $33 billion in 2014, compared with $31 billion in 2013, the year of the last available data. Crude oil and natural gas capital expenditures, which rebounded significantly after 2009, reached $27 billion in 2013 as activity in conventional basins shifted to using capital-intensive horizontal wells and multistage fracturing completion technology.

Alberta's Economy – Forecast

The AER expects the global economic growth that began after the 2008 recession to continue at a slower pace in the short and medium term. The rapid decline in oil prices, strong appreciation of the U.S. dollar, new international monetary policies, and China's slower economic growth are among the factors that can bring more uncertainty to the global economy. Economic growth is also expected to be slower in Canada and Alberta. Alberta's economic growth is expected to be 0.5 per cent in 2015, which is lower than Canada's expected growth rate. A weaker Canadian dollar, which the AER projects to be US$0.79 for 2015, will partially offset lower oil prices. Longer-term, Alberta's economic growth is expected to recover in conjunction with the commodity price forecast.

Oil sands expenditures are predicted to decrease to $25 billion in 2015. In late 2014 and early 2015, some oil sands companies announced capital spending cuts and delays in the development of upcoming projects. The decisions came from increased pressure of low crude oil prices and competition from lower cost conventional and tight oil developments in Canada and the United States.

Investment in oil and gas is projected to decrease to $13.6 billion in 2015. Investment is expected to recover after 2015 as crude oil prices strengthen over the forecast period and as producers continue to use capital-intensive technologies.

Production from upgraded and nonupgraded bitumen derived from the oil sands is projected to more than offset the decline in conventional resource production, increasing from 60 per cent of total energy revenues in 2014 to 73 per cent of total energy revenues in 2024.

Total investment in the conventional oil and gas and oil sands industry is projected to decrease to $38.6 billion in 2015, which is 31 per cent lower than 2014. However, investment in energy resource development, particularly in oil sands mining, upgrading, and in situ bitumen projects, will continue to drive Alberta's production, export growth, and the overall Alberta economy.

Commodities

Crude Bitumen and Crude Oil

Crude Bitumen Reserves

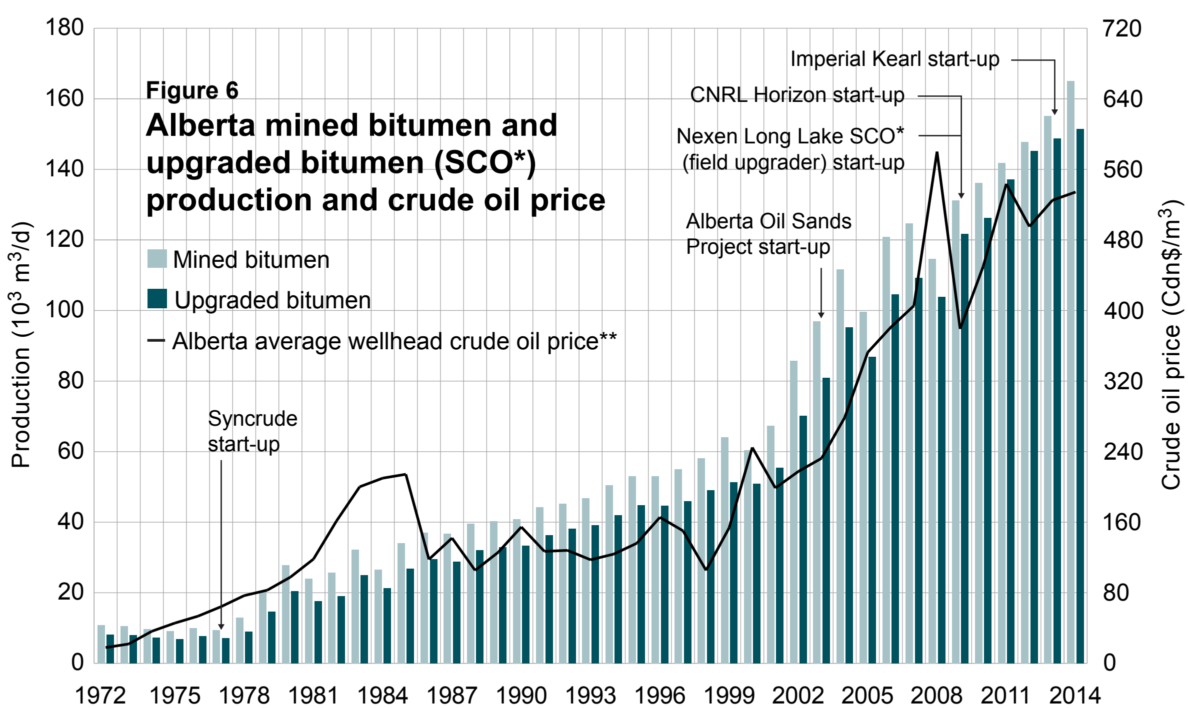
The total remaining established reserves of in situ and mineable crude bitumen is 26.4 billion cubic metres (m^3) (166.3 billion barrels), slightly less than in 2013 due to 0.13 billion m^3 of production. Only 5.9 per cent of the initial established crude bitumen reserves have been produced since commercial production started in 1967.

Crude Bitumen Production

Figure 6 shows the historical mined bitumen and upgraded bitumen production between 1971 and 2014. Production began with the start-up of Great Canadian Oil Sands (Suncor) in 1967 and has been followed by other projects, the most recent being Imperial Oil Limited's Kearl project. The figure also shows the average Alberta wellhead price of crude oil.

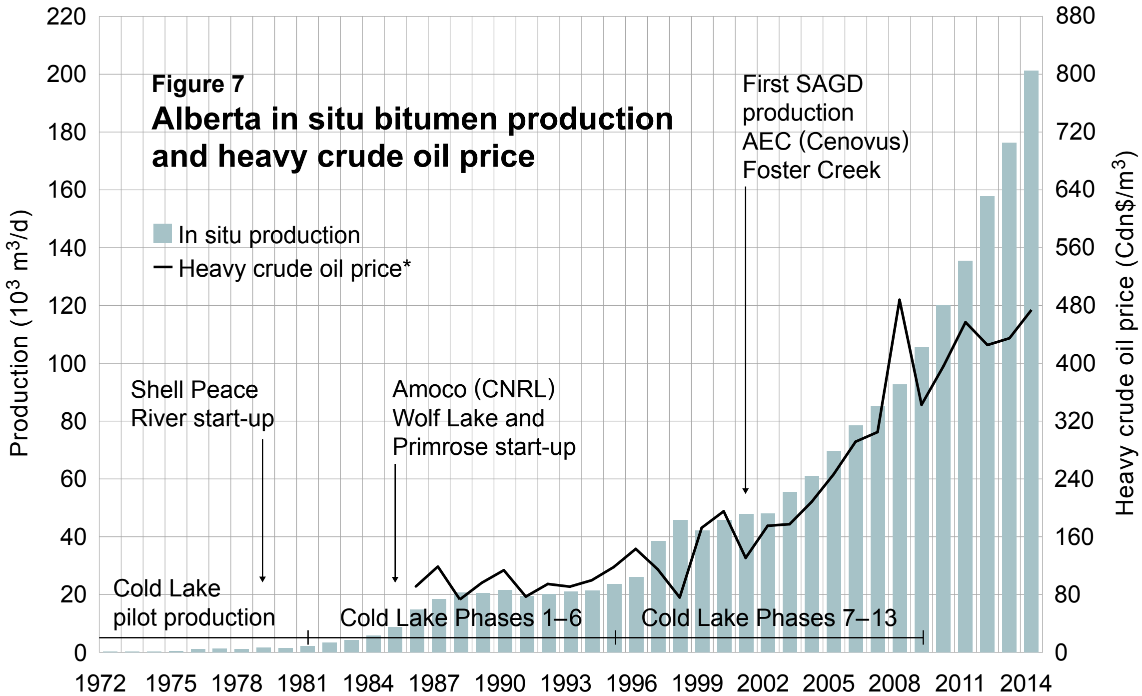
Historical in situ bitumen production and the price of heavy crude oil are shown in **Figure 7**. Regionally, in situ production growth in 2014 was strongest in Athabasca (24.9 per cent increase), followed by Peace River (1.2 per cent increase). Cold Lake experienced a slight decrease of 1.4 per cent.

In 2014, Alberta produced 60.3 million m^3 (379 million barrels) from mining and 73.4 million m^3 (462 million barrels) from in situ, totalling 133.7 million m^3 (841 million barrels). This is equivalent



* Synthetic crude oil.

** Source: CAPP *Statistical Handbook*.



* Source: AER's *ST3: Alberta Energy Resource Industries Monthly Statistics.*

to 366.3 thousand m³ (2.3 million barrels) per day. Total raw bitumen production is projected to reach 642 thousand m³ (4.0 million barrels) per day by 2024.

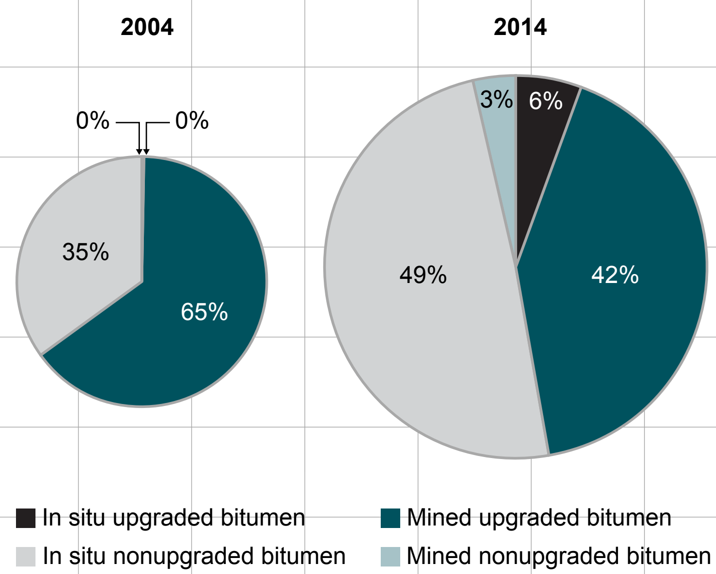
Production from in situ projects has exceeded mined production since 2012. In 2014, total in situ production accounted for 55 per cent of total bitumen production and is expected to reach 60 per cent in 2024.

The AER expects in situ crude bitumen production to increase to 384 thousand m³ per day in 2024, a slight increase compared to last year's forecast of 379 thousand m³/d by 2023. The AER projects that mined bitumen production will reach 258 thousand m³ per day in 2024, which is lower than last year's forecast due to some projects being either cancelled or delayed.

Upgraded Bitumen (SCO) Production

In 2014, 92.3 per cent of crude bitumen produced from mining and 10.5 per cent of in situ production were upgraded in Alberta, yielding 55.3 million m³ (348 million barrels) of upgraded bitumen. **Figure 8** shows that in 2014, 47.4 per cent of total produced crude bitumen was upgraded. Over the forecast period, this percentage is expected to decline to 36.7 per cent, mainly because of in situ production growth outpacing the growth in upgrading capacity. In 2024, upgraded bitumen production is forecast to increase to 73 million m³ (461 million barrels).

Figure 8
Percentage of mined and in situ bitumen sent for upgrading in Alberta



Over the next 10 years, mined bitumen is projected to continue to be the primary source of crude bitumen to be upgraded in Alberta. However, the percentage of in situ bitumen upgraded is expected to vary throughout the forecast period, before reaching about 8 per cent in 2024.

Crude Oil Reserves

The AER estimates the remaining established reserves of conventional crude oil in Alberta to be 288.2 million m^3 (1.8 billion barrels), representing more than one-third of Canada's remaining conventional reserves. This increase of 4.8 million m^3, or 1.6 per cent over the 2013 estimate, is from all reserve adjustments less production in 2014.

Annual production and remaining established reserves for crude bitumen and crude oil are presented in **Figure 9**.

Crude Oil Production

Alberta's historical conventional crude oil production and the average Alberta wellhead price are shown in **Figure 10**. The first major oilfield discovered in Alberta was in Turner Valley in 1914. The Turner Valley oilfield became a major source of oil and gas production and for a time was the largest source in the British Empire. The discovery of Leduc-Woodbend in 1947 jumpstarted Alberta crude oil production, which culminated in 1973 with a peak production of 227.4 thousand m^3 per day. Major events that affected Alberta's crude oil production and crude oil prices are also noted in the figure.

Figure 9

Alberta oil reserves

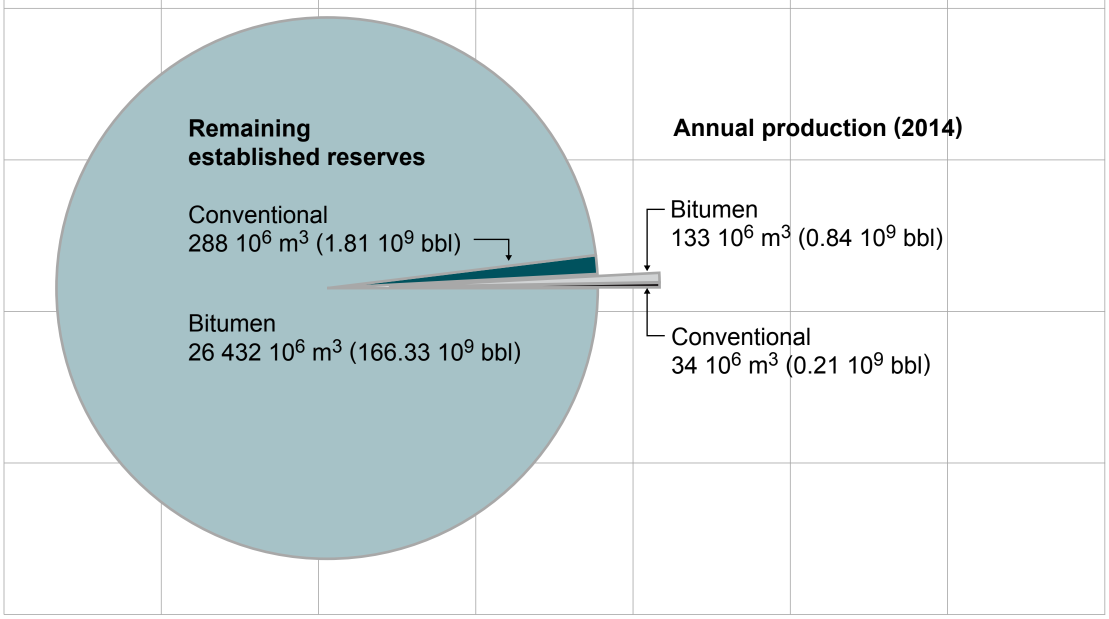
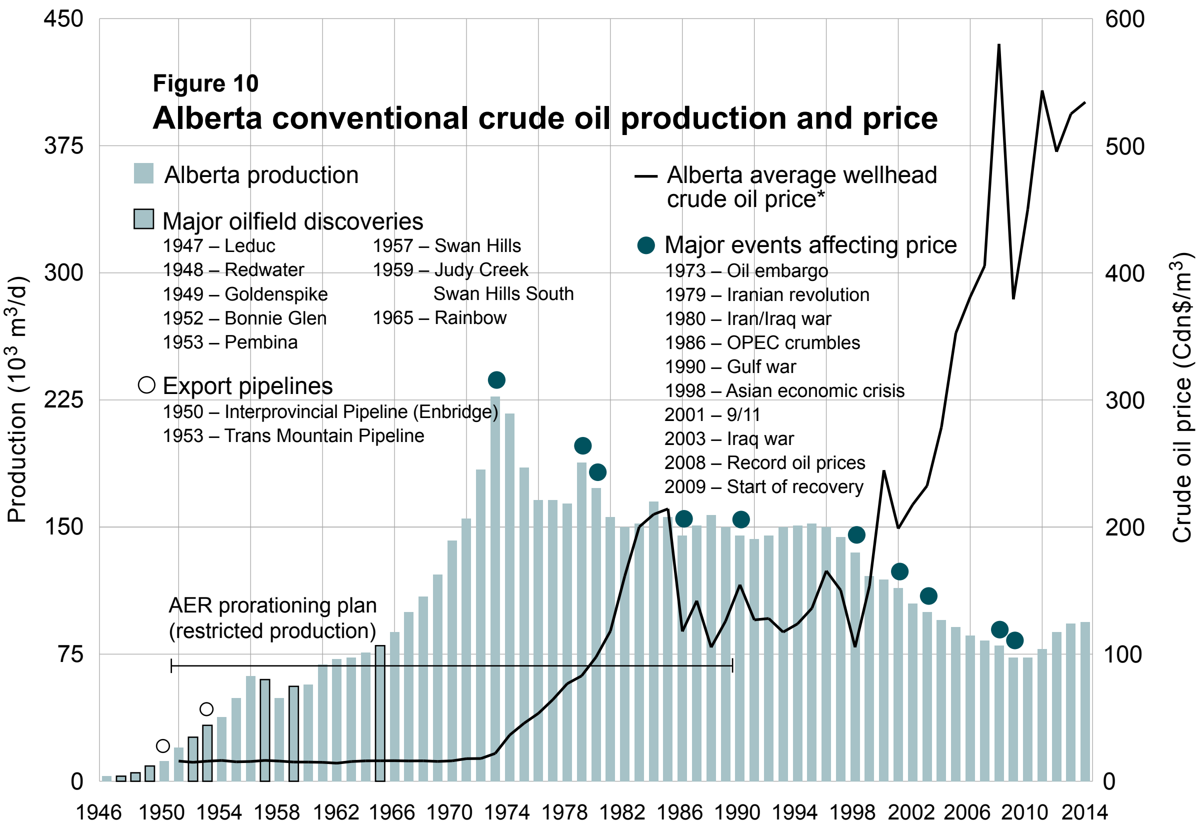


Figure 10

Alberta conventional crude oil production and price



* Source: CAPP *Statistical Handbook*.

In 2010, total crude oil production in Alberta reversed the downward trend that started in the early 1970s. Since 2010, light-medium crude oil production increased because of horizontal drilling activity and the introduction of multistage hydraulic fracturing completion technology. Alberta's production of conventional crude oil totalled 34.2 million m^3 (215 million barrels) in 2014, an increase of 1.3 per cent.

The AER believes that crude oil production peaked in 2014 and is expected to re-enter a period of slow decline.

Total Oil Supply and Demand

Figure 11 shows crude oil and equivalent supply. In 2014, Alberta's supply of crude oil and equivalent reached 463 thousand m^3 (2.9 million barrels) per day, a 9.4 per cent increase compared with 2013. Production is expected to reach 702 thousand m^3 (4.4 million barrels) per day by 2024.

A comparison of conventional oil and bitumen production over the last 10 years, as illustrated in **Figure 12**, clearly shows the increasing contribution of bitumen to Alberta's oil production.

The AER estimates that bitumen production will grow by about 76 per cent by 2024. Over the forecast period, as illustrated in **Figure 12**, the growth in production of upgraded and nonupgraded bitumen is expected to continue to offset the projected long-term decline in conventional crude oil. Upgraded and nonupgraded bitumen will account for 86 per cent of total production in 2024, compared with about 73 per cent in 2014.

Demand for oil produced in Alberta is from oil refineries, most of which are outside the province. Oil refineries use mainly crude oil, butanes, and natural gas as feedstock, along with upgraded and nonupgraded bitumen and pentanes plus, to produce a wide variety of refined petroleum products. Crude oil shipments outside of Alberta amounted to 81 per cent of total production in 2014.

Natural Gas

Historical gas production and prices are shown in **Figure 13**. In the 1950s and 1960s, natural gas was mainly produced as a by-product of crude oil production and was flared as a waste product. In 1980, through the National Energy Program, the federal government imposed regulated gas prices tied to crude oil prices. The resultant high gas prices led to an increase in drilling activity, which resulted in a significant oversupply of reserves. In 1985, natural gas prices were deregulated in Canada. The removal of set prices, the oversupply of reserves, and the drop in demand because of a recession resulted in the decline of natural gas prices for the rest of the decade.

In the late 1980s and early 1990s, natural gas prices trading points were created at Henry Hub and at Alberta Energy Company's storage hub (AECO-C)[8] (near Suffield, Alberta) to facilitate natural gas being traded as a North American commodity. More recently, shale gas production in the United States has significantly contributed to the growth in natural gas production, which has resulted in low gas prices in North America and contributed to the drop in natural gas activity in Alberta.

[8] The AECO-C hub is a trading point that sets the main pricing index for Albertan and Canadian natural gas.

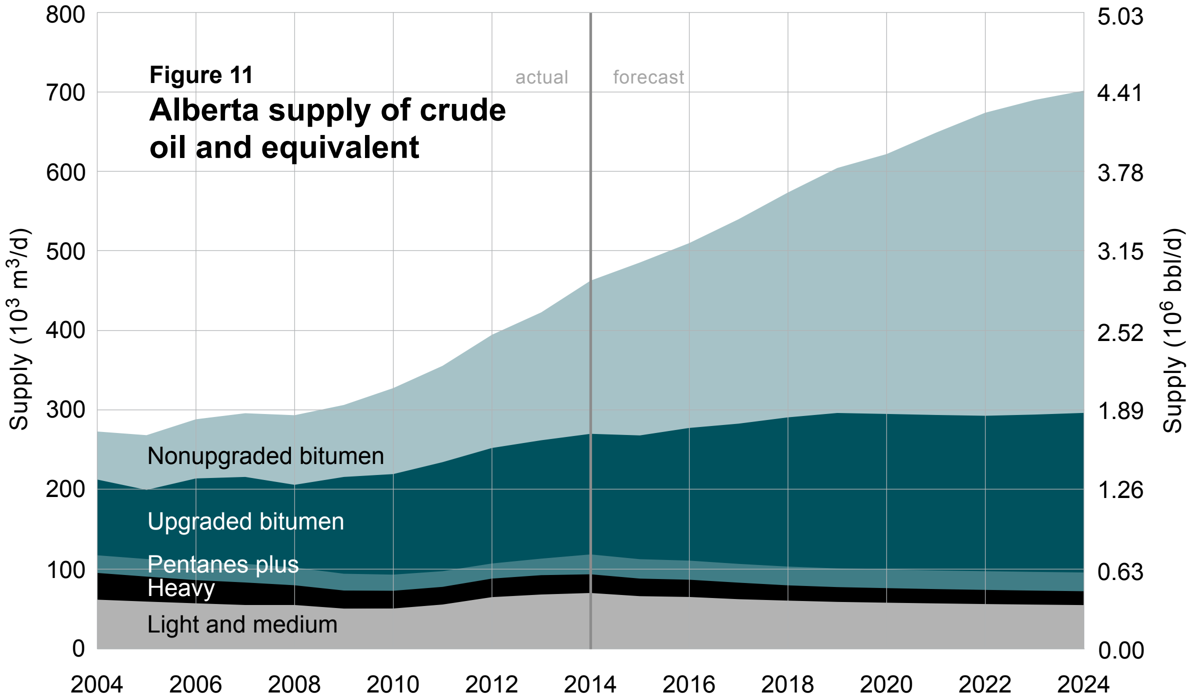


Figure 11
Alberta supply of crude oil and equivalent
actual
forecast
Nonupgraded bitumen
Upgraded bitumen
Pentanes plus
Heavy
Light and medium
Supply (10^3 m^3/d)
Supply (10^6 bbl/d)
800
700
600
500
400
300
200
100
0
5.03
4.41
3.78
3.15
2.52
1.89
1.26
0.63
0.00
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024

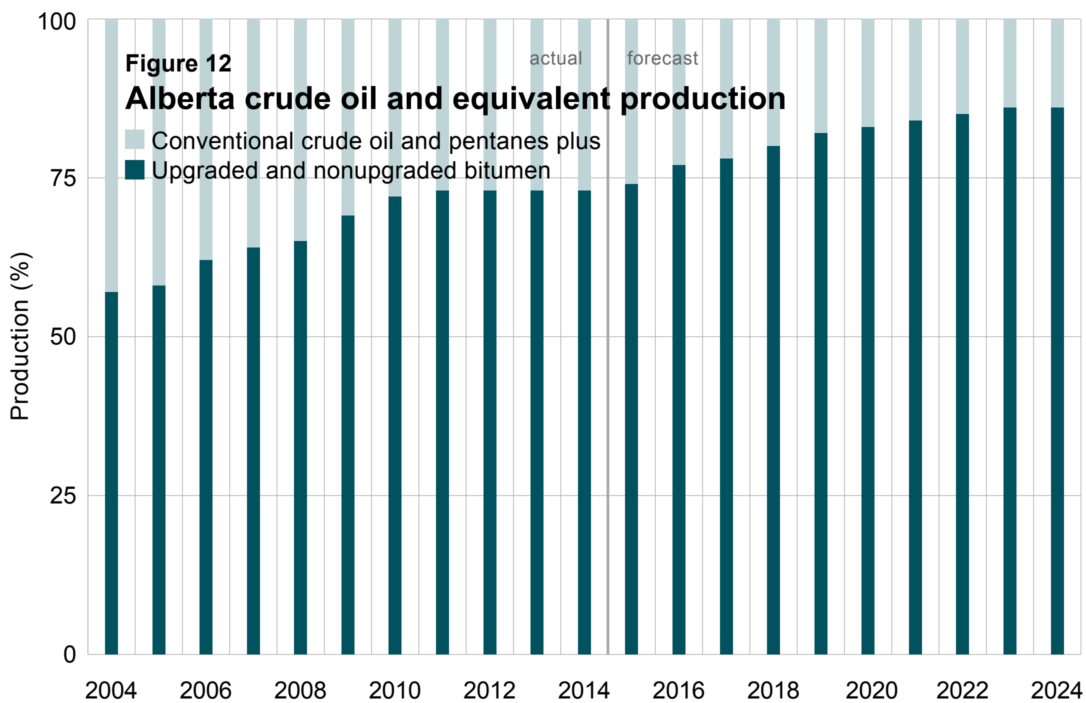


Figure 12
Alberta crude oil and equivalent production
actual
forecast
Conventional crude oil and pentanes plus
Upgraded and nonupgraded bitumen
Production (%)
100
75
50
25
0
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024

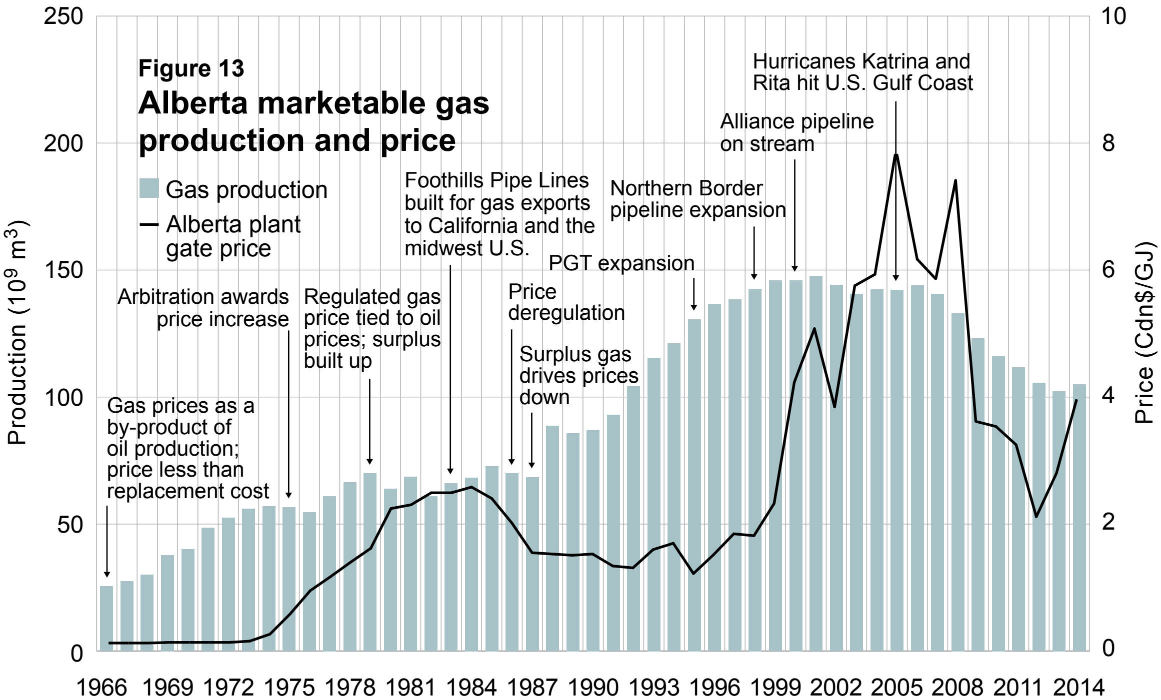


Figure 13
Alberta marketable gas production and price

Natural gas is produced from conventional and unconventional reserves in Alberta, where unconventional gas includes coalbed methane (CBM) and shale gas. Marketable gas is the gas that remains after the raw gas is processed to remove constituents and that meets specifications for use as a fuel. Marketable gas reserves are determined by applying a surface loss or shrinkage factor to the raw gas volume. Most marketable natural gas in Alberta is produced from conventional sources.

Conventional Natural Gas Reserves

As of December 31, 2014, the AER estimates the remaining established reserves of marketable conventional gas in Alberta downstream of field plants to be 865 billion m^3, with a total energy content of about 34 exajoules. This decrease of 32.2 billion m^3 since December 31, 2013, is the result of all reserves additions less production during 2014. These reserves include 28.7 billion m^3 of ethane and other NGLs, which are present in marketable gas leaving the field plant but are then recovered at straddle plants. Removal of NGLs reduces the average heating value by 4.6 per cent, from 39.2 megajoules per m^3 to 37.4 megajoules per m^3, for gas downstream of straddle plants. Reserves added through drilling (new plus development) totalled 29.0 billion m^3, replacing 30 per cent of Alberta’s 2014 production. This is down from 36 per cent in 2013, but is still higher than in 2012, which at 25 per cent was the lowest replacement ratio in the last 15 years.

Unconventional Natural Gas Reserves

The AER estimates the initial established reserves of CBM to be 103.1 billion m^3 as of December 31, 2014, relatively unchanged from 2013. Remaining established reserves in 2014 were 47.8 billion m^3, down from 51.5 billion m^3 in 2013 due to production.

Total Natural Gas Production

Several major factors affect natural gas production, including natural gas prices, the number of producing wells, the accessibility of Alberta's remaining reserves, and the performance characteristics of wells. In 2014, total marketable natural gas production in Alberta, including unconventional production, increased by 2.3 per cent to 287.3 million m^3 per day from 280.9 million m^3 per day. Total production from identified CBM and CBM hybrid wells decreased 9 per cent in 2014 to 19.0 million m^3 from the 2013 volume of 20.9 million m^3 per day. In 2014, natural gas from conventional gas and oil wells, at 265.2 million m^3 per day (standardized to 37.4 megajoules per m^3), represented 92 per cent of production. The remaining 8 per cent of gas supply came from CBM and minor shale gas wells at 19.0 million m^3 per day and 3.0 million m^3 per day, respectively. While shale gas has the lowest share in total production, its production increased by four times in 2014 compared to 2013.

Total Natural Gas Supply and Demand

The AER believes that new wells placed on production will not be able to offset production declines from existing wells over the forecast period.

Despite declining natural gas supply from conventional sources, sufficient supply exists to meet Alberta's demand. In 2014, about 48 per cent of Alberta production was consumed within Alberta compared with 50 per cent in 2013. The remainder was sent to other Canadian provinces and the United States. By the end of the forecast period, domestic demand in Alberta is forecast to represent about 75 per cent of total Alberta natural gas production, not including potential shale gas production or natural gas imports from British Columbia that connects to the pipeline network in Alberta.

Therefore, as Alberta requirements continue to increase and production continues to decline, less gas is forecast to be available for removal from the province. Alberta's historical and forecast marketable gas production (at 37.4 megajoules per m^3) and demand are shown in **Figure 14**.

Ethane and Other Natural Gas Liquids

Ethane Reserves

As of December 31, 2014, the AER estimates remaining established reserves of extractable ethane to be 106.5 million m^3 in liquefied form. This estimate considers the recovery of liquid ethane from raw gas extracted at field and straddle plants in Alberta based on existing technology and market conditions.

Ethane Production

In 2014, ethane volumes extracted from conventional gas and oil sands off-gas at Alberta processing facilities decreased slightly to 36.1 thousand m^3 per day from 36.7 thousand m^3 per day in 2013. About 71 per cent of total ethane in the gas stream was extracted in 2014, while the remainder was left in the gas stream and sold for its heating value. This figure was 75 per cent in 2013. The AER expects that Alberta ethane supply will moderately increase until 2017 before slightly declining and leveling off by 2024. Alberta ethane supplies are expected to continue to come from liquids-rich natural gas and oil sands off-gas. Ethane imports from the United States

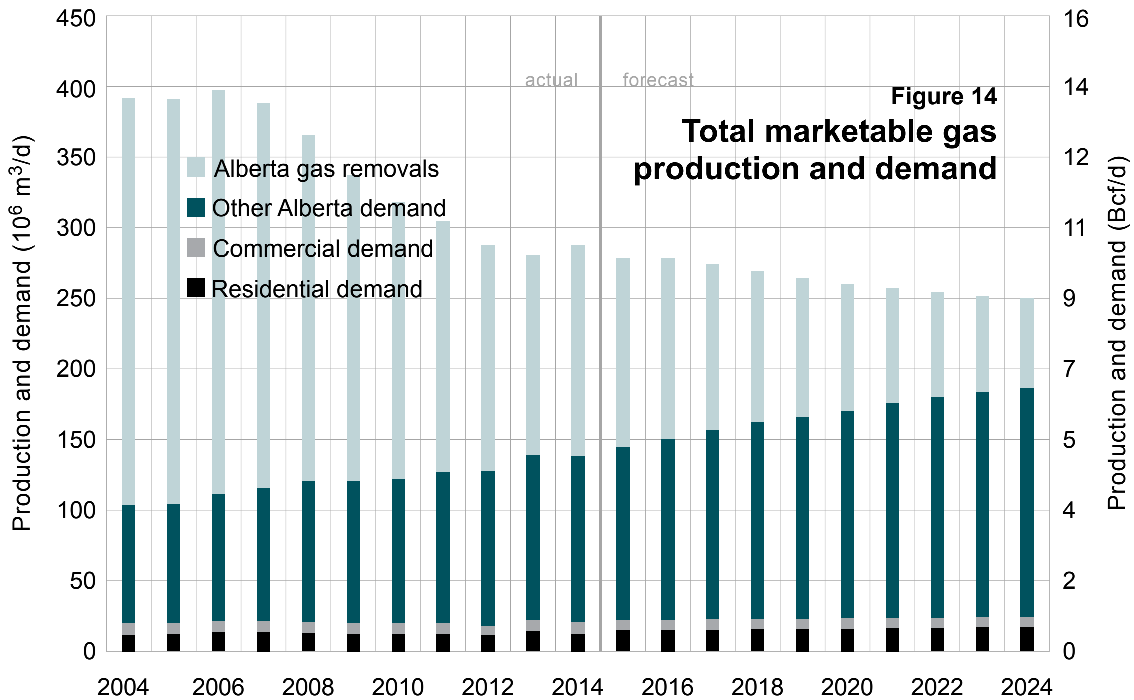


Figure 14
Total marketable gas production and demand

started in the second quarter of 2014 and averaged 2.2 thousand m^3 per day for 2014. The imports are projected to continue to increase throughout the forecast period, reaching 5.7 thousand m^3 per day in 2024.

Propane, Butane, and Pentanes Plus Reserves

As of December 31, 2014, the AER estimates remaining extractable reserves of propane, butanes, and pentanes plus to be 64.0 million m^3, 34.7 million m^3, and 42.7 million m^3, respectively. Cumulatively, these NGL reserves equate to 65 per cent of Alberta's remaining light-medium crude oil reserves. This is a decrease from 101 per cent in 2000 due to the decline in NGL reserves and the recovery of light-medium crude oil reserves over that period.

Propane, Butane, and Pentanes Plus Production

Propane, butanes, and pentanes plus production increased by 1.3, 2.2, and 19.9 per cent, respectively, in 2014. The significant increase of pentanes plus production, in addition to the general trend of developing the liquids-rich formations, is due to targeting the condensate window of these formations. In 2014, pentanes plus production surpassed heavy oil production for the first time in recent history in Alberta.

Over the forecast period, the supply of propane and butanes is expected to exceed demand. Although production of pentanes plus has increased significantly, supply remains lower than Alberta demand and additional volumes are required; therefore, Alberta currently imports condensate by pipeline and rail. Additionally, alternative sources of diluent are being used by industry to dilute heavier crudes to meet pipeline quality.[9]

[9] Condensate and upgraded bitumen are two main types of diluent used to lower the viscosity of bitumen for transport in pipelines, although naphtha, light crude oil, and butanes can also be used to enable bitumen to meet pipeline specifications.

Sulphur

Sulphur Reserves

The AER estimates the remaining established reserves of elemental sulphur in the province as of December 31, 2014, to be 114.2 million tonnes, down 3 per cent from 2013. This decrease is mainly due to production.

Sulphur Production

There are three main sources of sulphur production in Alberta: sour natural gas processing, bitumen upgrading, and crude oil refinement into petroleum products. In 2014, Alberta produced 4.17 million tonnes of sulphur, of which 2.10 million tonnes were derived from sour gas, 2.05 million tonnes from upgrading of bitumen, and just 15 thousand tonnes from oil refining. The total sulphur production in 2014 represents a decrease of 6.5 per cent from 2013 levels due to lower production from sour gas. Most of Canada's sulphur is produced in Alberta and is mostly transported outside the province.

Figure 15 illustrates historical sulphur closing inventories at processing plants and oil sands operations and sulphur prices at Free On Board (FOB) Vancouver.[10] When international demand is high, Alberta sulphur blocks are used as an additional source of supply.

Canadian exports in 2014 were 2.6 million tonnes, a 21 per cent decrease from 2013. Nearly 44 per cent of the exports, 1.13 million tonnes, were sent to the United States in 2014; down from 1.58 million tonnes in 2013.

Coal

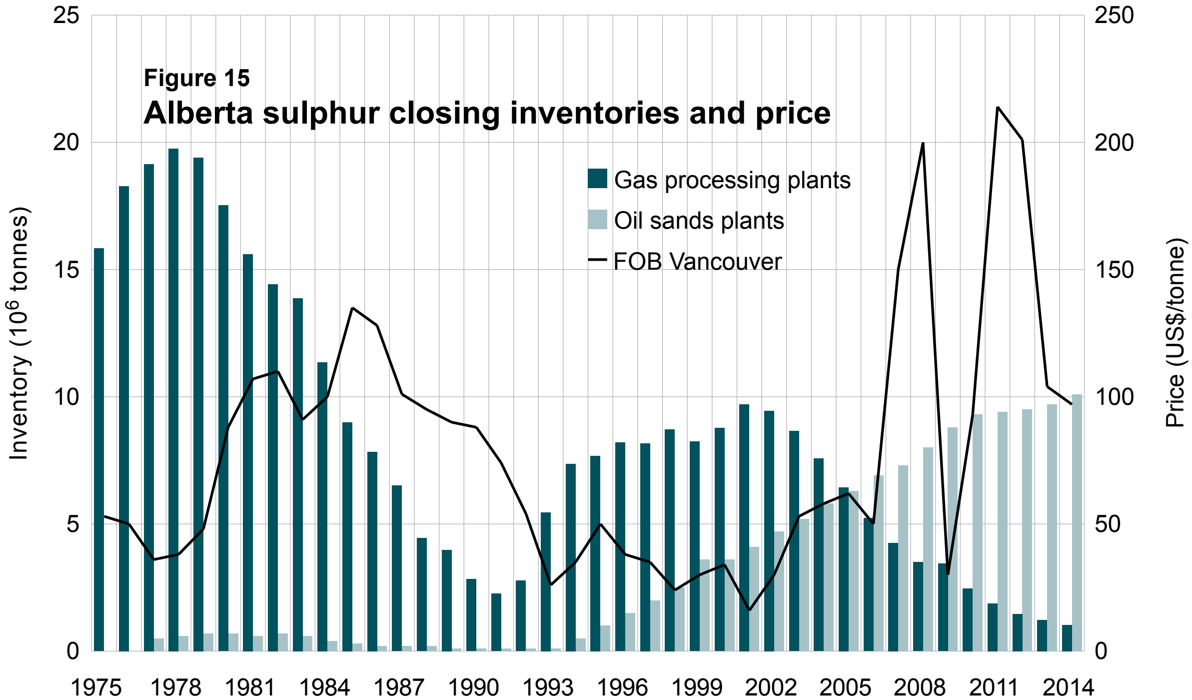
Coal Reserves

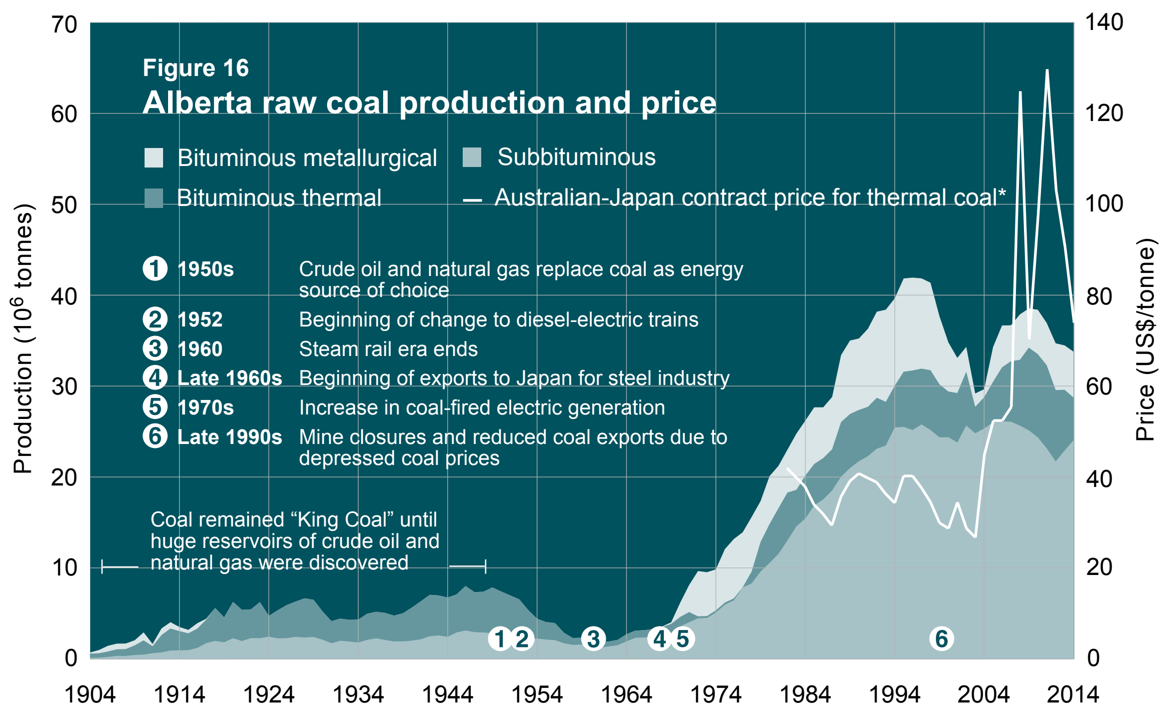
The AER estimates the remaining established reserves of all types of coal in Alberta as of December 31, 2014, to be 33.2 billion tonnes (36.6 billion tons). Of this amount, about 68 per cent is considered recoverable by underground mining methods and about 32 per cent is recoverable by surface mining methods. Alberta's coal reserves represent more than a thousand years of supply at current production levels.

Coal Production

Alberta's coal production dates back to the 1800s, when coal was used mainly for domestic heating and cooking. Historical raw coal production by type is illustrated in **Figure 16**. The export prices for coal are based on bituminous thermal coal contract prices for Australian coal shipped to Japan (often referred to as Newcastle thermal coal) and are used as a benchmark in this report. Australia is the world's largest exporter of coal. Subbituminous coal produced in Alberta is mainly used in the province for power generation, and cost-of-service contracts with the mining companies generally determine the price.

[10] FOB Vancouver represents an international pricing point where, after a commodity is loaded on a ship, the liability for and the cost of shipping the commodity transfers from a seller to a buyer.





*Source: Australian Bureau of Agricultural and Resource Economics.

In 2014, nine mines produced coal in Alberta. These mines produced 29.6 million tonnes of marketable coal. Subbituminous coal accounted for 81 per cent of the total, metallurgical bituminous coal for 11 per cent, and thermal bituminous coal for the remaining 8 per cent. Overall, total marketable production of coal increased by 1.9 per cent over 2013, mainly due to increased demand for electricity from coal-fired units when natural gas prices were relatively high in 2014.

Alberta's metallurgical coal primarily serves the Asian steel industry. Japan, South Korea, and Brazil were the leading importers of the province's metallurgical coal in 2014, dropping China from second to fourth when compared to 2013. Japan also imports the most thermal coal from Alberta. The long distance required to transport coal from mine to port creates a competitive disadvantage for Alberta export-coal producers. However, the demand for metallurgical coal exports decreased by 2 per cent in 2014 from 2013.

Electricity

The AER does not publish a perspective on supply and demand for Alberta's electricity sector. Information on electricity, including the market outlook, is provided by the Alberta Electric System Operator (AESO).

Drilling Activity

Figure 17 illustrates the province's drilling history over the past six decades, together with the price of natural gas. Historically, most drilling in Alberta is related to successful gas wells relative to crude oil wells, although this trend reversed in 2011 and continued in 2014.[11] Drilling activity peaked in 2005 and has declined since then. This trend is consistent with industry drilling more horizontal wells and fewer vertical wells in recent years. Horizontal wells in general are now longer than they were in the 1980s and 1990s. Many of these horizontal wells employ multistage fracturing technologies to enhance production from low permeability reservoirs.

The higher percentage of longer horizontal wells has significantly increased the average kilometres drilled per well in the last few years. The supporting data for **Figure 17** are in **Appendix D**.

Figure 18 shows where oil and gas producers have licensed and drilled wells in Alberta since the early 1900s. Within **Figure 18** the total number of licensed wells shown has been overlain by those wells where at least one reservoir rock unit has been fractured by a completion technique to enhance production. These in turn are overlain by those horizontal wells where operators have used multistage fracturing completion on at least one reservoir rock.

Other than the national and provincial parks located in the southwest and the northeast part of the province, almost all areas of Alberta have seen some level of drilling activity. In the southeast portion of the province, an area that traditionally maintained about 50 per cent of conventional gas activity, natural gas producers have

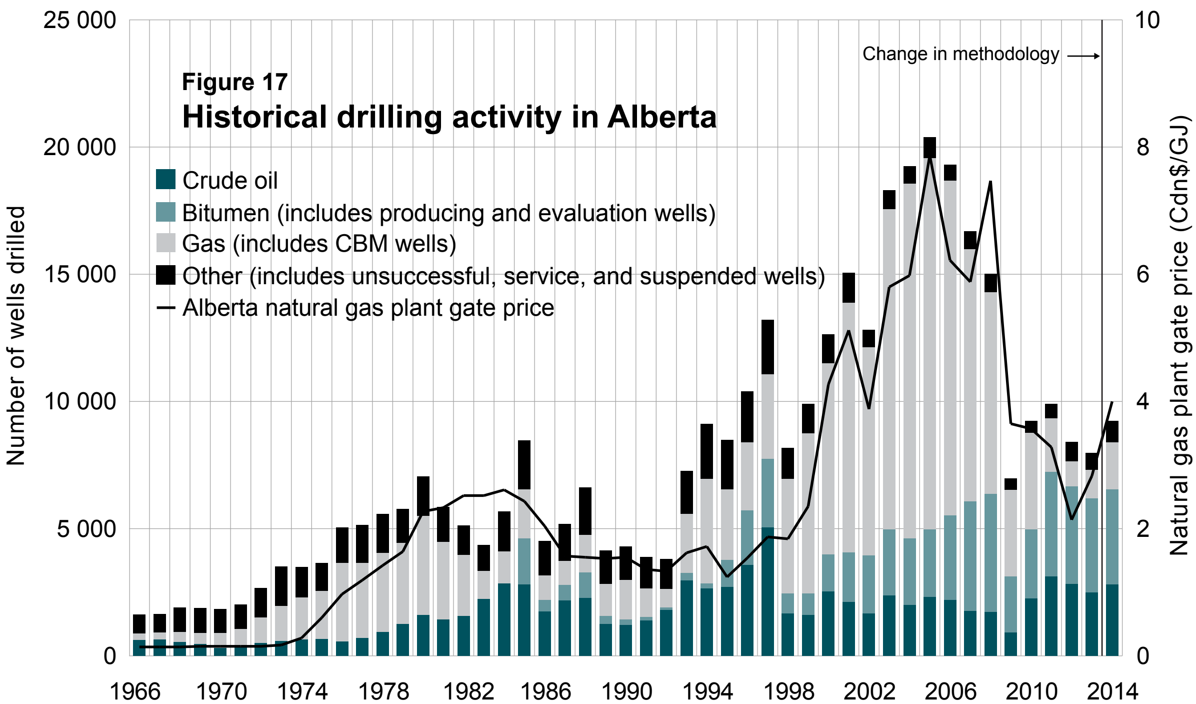
[11] Starting in 2014, the methodology to compile the drilling statistics was changed to incorporate enhancements to the content and is consistent with the AER's *ST59: Alberta Drilling Activity Monthly Statistics* report. Previous to 2014, wells that were drilled but did not come on production were excluded from the count. To represent all provincial drilling activity, these wells are now included.

targeted shallow gas pools. Recently this trend has shifted towards gas with extractable liquids, often found along the front of the foothills of the province. Crude oil producers have long focused their attention on the Cardium Formation in the Pembina area of west-central Alberta. Starting around 2008, crude oil producers began using horizontal wells with multistage fracturing completion technology to drill along the periphery of main pools into reservoir areas with low permeability. Since then, operators have used horizontal wells with this completion technology in the Cardium Formation and other areas in Alberta such as the Montney and Duvernay Formations in Alberta's northern foothills and adjacent plains areas.

Wells located in the northeast section of the province mainly represent oil sands exploration and development. Drilling for coal, similar to oil and gas in being both numerous and widespread, is not shown in **Figure 18** but is shown in **Figure R8.2**.

Figure 17

Historical drilling activity in Alberta



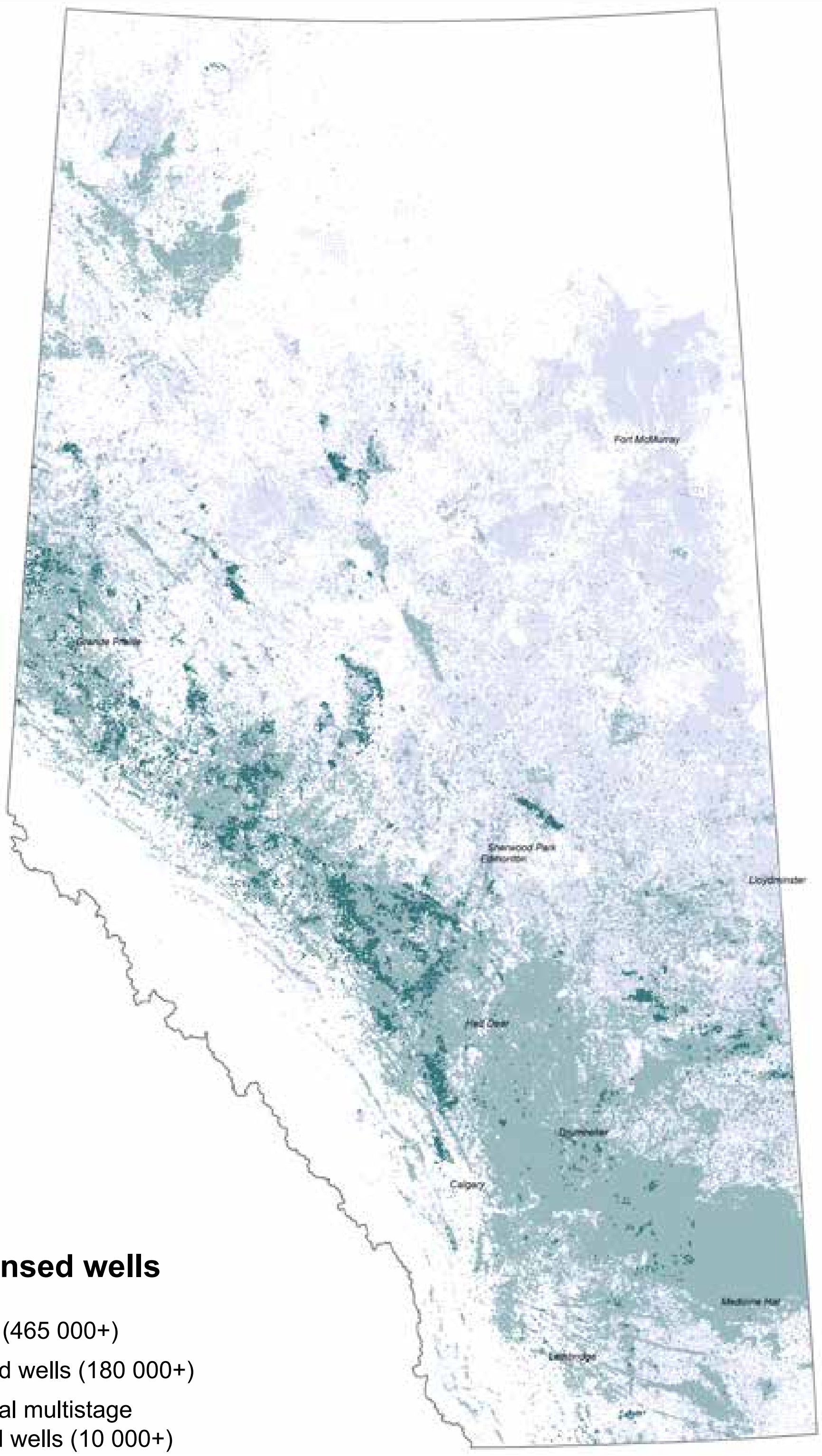


Figure 18
AER-licensed wells

- All wells (465 000+)
- Fractured wells (180 000+)
- Horizontal multistage fractured wells (10 000+)

Data cumulative to December 31, 2014

HIGHLIGHTS

WTI crude oil prices averaged US$93.00 per barrel in 2014, compared with US$98.05 per barrel in 2013, a decrease of five per cent. It is expected to average US$52.00 per barrel in 2015.

Alberta wellhead natural gas prices averaged Cdn$4.00 per gigajoule in 2014, compared with Cdn$2.83 per gigajoule in 2013, an increase of 41 per cent. It is expected to average Cdn$2.83 per gigajoule in 2015.

The value of upgraded and nonupgraded bitumen production averaged Cdn$66.5 billion in 2014, compared with Cdn$57.4 billion in 2013, an increase of sixteen per cent.

1 ECONOMICS

Decisions on energy production are influenced by energy prices, technology, costs, demand, and remaining reserves. Energy demand, in turn, is determined by factors such as energy prices, economic activity, standard of living, seasonal temperatures, and population. This section introduces some of the main variables affecting Alberta's energy sector and sets the stage for later discussions in this report. **Table 1.1** summarizes the energy prices discussed in **Section 1.1**.

Table 1.1 Energy prices and change highlights

	2014	2013	Change	Change (%)
Oil prices (US$/bbl)[a]				
Brent Blend	99.02	108.44	−9.42	−8.7
West Texas Intermediate	93.00	98.05	−5.05	−5.2
Western Canadian Select	71.77	73.01	−1.24	−1.7
Natural gas prices (Cdn$/GJ)[b]				
AECO-C[c]	4.21	3.03	+1.18	+8.9
Alberta Reference Price	4.00	2.83	+1.17	+41.3

[a] US$/bbl = U.S. dollars per barrel.

[b] Cdn$/GJ = Canadian dollars per gigajoule.

[c] The AECO-C hub is a trading point that represents the main pricing index for Albertan and Canadian natural gas. The price is the volume weighted average of transacted prices for all physically delivered natural gas in a calendar month at the Alberta AB-NOVA Inventory Transfer (NIT) market centre. Starting this year, this report uses the AECO-C price reported by NGX Alberta instead of by CAPP. The historical data in the figures and graphs have been updated to reflect this new source.

1.1 Energy Prices

1.1.1 World Oil[1] Market[2]

In 2014, average world oil demand rose by 0.7 million (10^6) barrels per day (bbl/d) to 92.5 10^6 bbl/d (14.7 10^6 cubic metres per day [m^3/d]), a 0.7 per cent change from 2013. The International Energy Agency (IEA) reported that average net oil consumption in the Organisation for Economic Co-operation and Development (OECD) decreased by 0.5 10^6 bbl/d (0.1 10^6 m^3/d) to 45.6 10^6 bbl/d (7.3 10^6 m^3/d), following an increase in 2013, which was the first increase since 2010. Total non-OECD net oil consumption increased by 1.2 10^6 bbl/d (0.19 10^6 m^3/d) to 46.9 10^6 bbl/d (7.5 10^6 m^3/d).

[1] Within **Section 1.1.1**, oil refers to crude oil, condensates, natural gas liquids, refinery feedstocks and additives, other hydrocarbons, and petroleum products.

[2] Statistics obtained from the International Energy Agency's *Oil Market Report* (March 2015).

Figure 1.1 illustrates changes in oil demand across the globe in 2013 and 2014, along with the most recent forecast for 2015 by the IEA. The IEA projects that world oil demand will increase by 0.99 10^6 bbl/d (0.2 10^6 m^3/d) in 2015, or 1.1 per cent, to 93.5 10^6 bbl/d (14.9 10^6 m^3/d).

In 2014, the Organization of Petroleum Exporting Countries (OPEC) produced 36.7 10^6 bbl/d (5.8 10^6 m^3/d), similar to the 36.7 10^6 bbl/d (5.8 10^6 m^3/d) produced in 2013. OPEC production in 2014 satisfied about 39 per cent of total world oil demand, down from 40 per cent in 2013. Non-OPEC oil production increased from 54.6 10^6 bbl/d (8.7 10^6 m^3/d) in 2013 to 56.7 10^6 bbl/d (9.0 10^6 m^3/d), mainly due to increasing production in the United States. In 2014, the world's top three oil producing countries (the United States, Russia, and Saudi Arabia) produced 35 per cent of total oil supply, producing 11.8 10^6 bbl/d (1.9 10^6 m^3/d), 10.9 10^6 bbl/d (1.7 10^6 m^3/d), and 9.5 10^6 bbl/d (1.5 10^6 m^3/d), respectively. In 2014, the United States produced more oil than any other country for the first time since 2002.

1.1.2 International Oil Prices

Monthly average world oil prices for 2014, represented by the price of Brent Blend (Brent)[3] and the price of West Texas Intermediate (WTI)[4] are shown in **Figure 1.2.** In the first half of 2014, Brent prices averaged US$108.17/bbl and then weakened significantly in the second half of the year, reaching a low of US$62.34/bbl and averaging US$99.02/bbl by the end of 2014. The WTI price averaged US$93.00/bbl in 2014, reaching a high of US$105.15/bbl in June and a low of US$59.29/bbl in December.

In the first half of 2014, crude oil prices strengthened in response to modest global economic recovery, continued tension in the Middle East, and the recent conflict between Ukraine and Russia. Prices began to fall in June 2014 mainly due to

- weakening demand growth in Europe and China,
- increasing non-OPEC production (particularly in North America), and
- OPEC's decision not to sacrifice its own market share to restore the price.

The 2014 differential between the prices of WTI and Brent is highlighted in **Figure 1.2.** In 2014, WTI began trading at a US$13.26/bbl discount to Brent. The differential narrowed in the first quarter of the year, mainly because of changes to crude oil transportation infrastructure in North America, causing WTI prices to rise. The differential averaged US$5.86/bbl from March through September. The narrowing continued in the fourth quarter, reaching US$3.05/bbl, largely as the result of declining Brent price. The decline in Brent price, caused by a combination of lower demand and increased supply, resulted in an average 2014 differential of US$6.02/bbl.

3 Brent is a blend of light sweet crude oil from 15 different oil fields in the North Sea. Brent Blend futures are traded on the Intercontinental Exchange Inc. and are considered a global benchmark for oil prices.

4 WTI is a light sweet grade of crude oil that is typically referenced for pricing purposes at Cushing, Oklahoma.

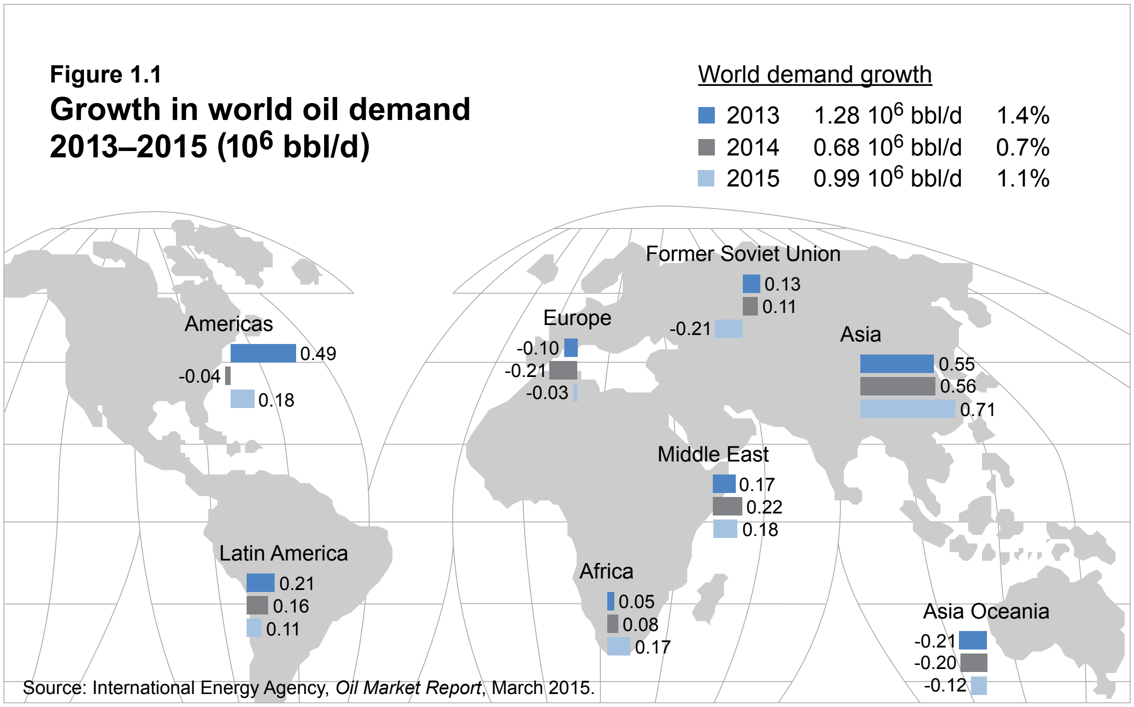


Figure 1.1
Growth in world oil demand 2013–2015 (10^6 bbl/d)
World demand growth
2013 1.28 10^6 bbl/d 1.4%
2014 0.68 10^6 bbl/d 0.7%
2015 0.99 10^6 bbl/d 1.1%
Americas
0.49
-0.04
0.18
Latin America
0.21
0.16
0.11
Europe
-0.10
-0.21
-0.03
Former Soviet Union
0.13
0.11
-0.21
Asia
0.55
0.56
0.71
Middle East
0.17
0.22
0.18
Africa
0.05
0.08
0.17
Asia Oceania
-0.21
-0.20
-0.12
Source: International Energy Agency, *Oil Market Report*, March 2015.

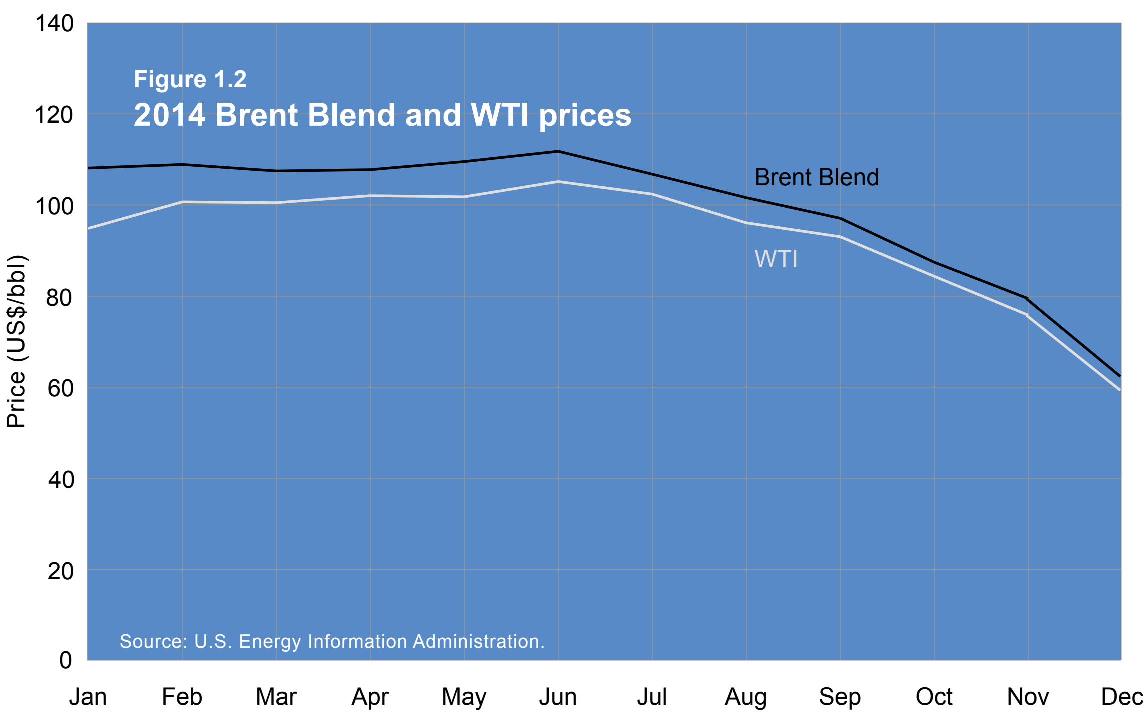


Figure 1.2
2014 Brent Blend and WTI prices
Brent Blend
WTI
Price (US$/bbl)
140
120
100
80
60
40
20
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Source: U.S. Energy Information Administration.

Figure 1.3 shows the historical yearly average Brent and WTI prices. Historically, the two benchmarks traded in line with each other. However, in 2010, WTI began trading at a discount to Brent due to an increase in North American oil production (**Figure 1.4**), creating an oversupply in the mid-continental market. In early 2014, the differential narrowed and averaged US$6.02/bbl due to growing pipeline capacity and a growing supply of oil worldwide, which caused Brent prices to fall.

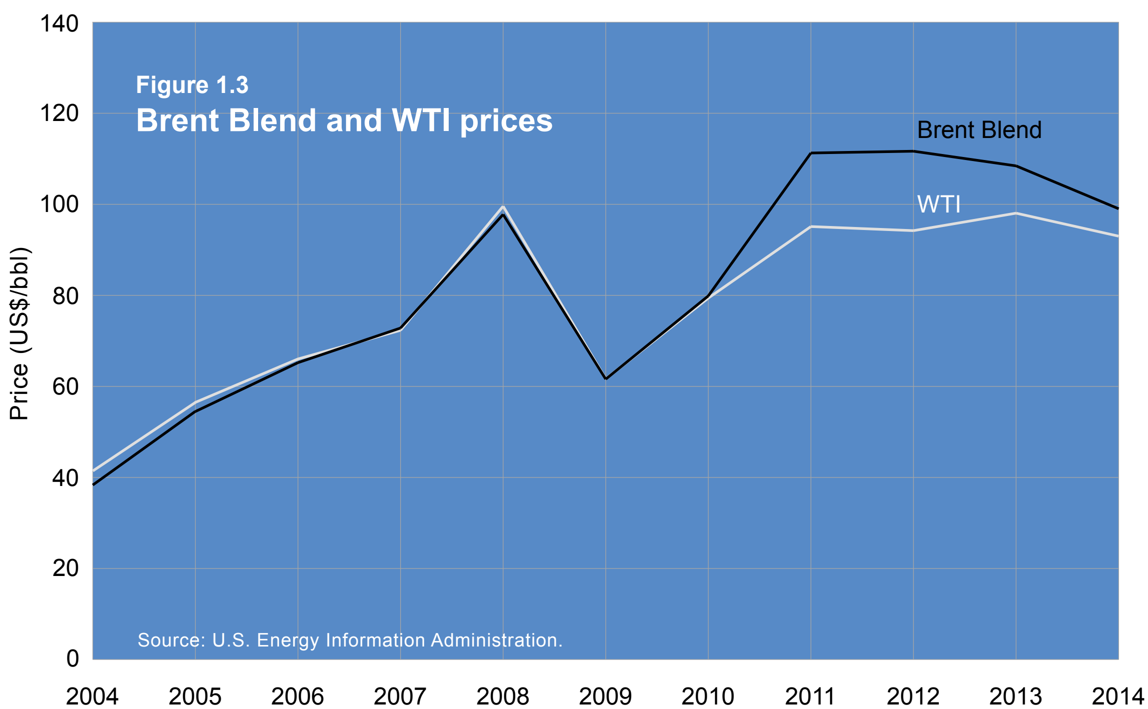
1.1.3 North American Crude Oil Prices

North American crude oil prices are based on the price of WTI crude oil at Cushing, Oklahoma, which is the underlying physical commodity market for the New York Mercantile Exchange (NYMEX) for light crude oil contracts. WTI crude oil has an American Petroleum Institute (API) gravity of 40 degrees and a sulphur content of less than 0.5 per cent.

The significant increase in U.S. domestic crude oil production has been contributing to the WTI discount relative to the Brent price. Unconventional oil production has significantly added to the U.S. growth in supply over the last six years as multistage fracturing completion technology is being used to access crude oil in reservoirs previously considered uneconomic.

In 2014, the WTI price averaged US$93.00/bbl, down US$5.05/bbl from 2013. The AER projects WTI to average US$52.00/bbl in 2015, with a range of US$41.60/bbl to US$62.40/bbl. **Figure 1.5** shows historical and forecasted WTI prices at Cushing.

As illustrated in **Figure 1.5**, the AER projects the price of WTI to increase throughout the forecast period. The near-term WTI forecast reflects the increased North American and world oil supply, declining demand in OECD



countries, slower economic growth in China, and the continued WTI discount due to pipeline constraints near Cushing. The long-term forecast reflects expectations that transportation constraints will be alleviated and that global economic conditions will improve. By 2024, WTI prices are projected to be US$98.63/bbl, ranging between US$78.91/bbl to US$118.36/bbl. This forecast is slightly lower than last year's forecast.

As previously discussed, and shown in **Figure 1.4**, the declining trend in crude oil production in the United States reversed in 2009 and production increased from an average of 5.4 10^6 bbl/d (0.9 10^6 m^3/d) in 2009 to 8.7 10^6 bbl/d (1.4 10^6 m^3/d) in 2014, a 61.7 per cent increase. Production increased by 16.2 per cent in 2014, the largest year-over-year increase since 1940 and the highest level of average U.S. production since 1986.

In North Dakota, crude oil production averaged 1087 10^3 bbl/d (173 10^3 m^3/d) in 2014, an increase of 26 per cent from 2013 levels. Light crude production from the Bakken Formation accounts for 90 per cent of North Dakota's total oil production, which has surpassed Alberta's conventional crude oil production by about 67 per cent, up from 50 per cent in 2013. The increased supply of light crude has also depressed all Canadian crude prices because Alberta crude oil is competing with Bakken crude for pipeline space. In Texas, onshore production of crude oil averaged 3159 10^3 bbl/d (502 10^3 m^3/d) in 2014, a significant increase of 25 per cent from 2013 levels. U.S. crude oil production is discussed further in **Section 4.2.1.2**.

Crude oil inventories at the Cushing storage hub declined throughout 2014, reaching 31.9 10^6 bbl (5.1 10^6 m^3) on December 31, 2014, down 22.9 per cent from a year ago. Several new crude oil transportation projects came on line in early 2014, including pipelines and crude-by-rail terminals. This new infrastructure helped to clear transportation bottlenecks in the U.S. mid-continent and increased the ability to ship crude oil in pipelines both to and from Cushing. In early 2015, however, storage levels at Cushing have been increasing to record levels, with Cushing inventory levels in the first two months of 2015 increasing by about 2.2 10^6 bbl (on a net basis).

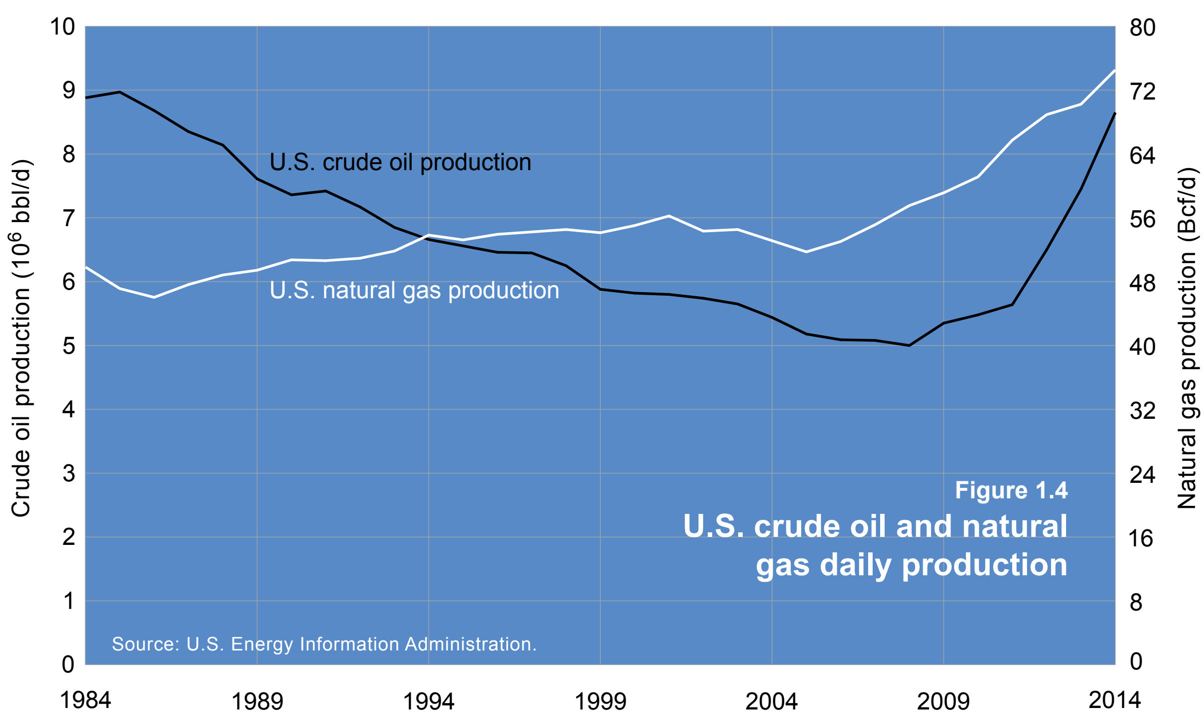
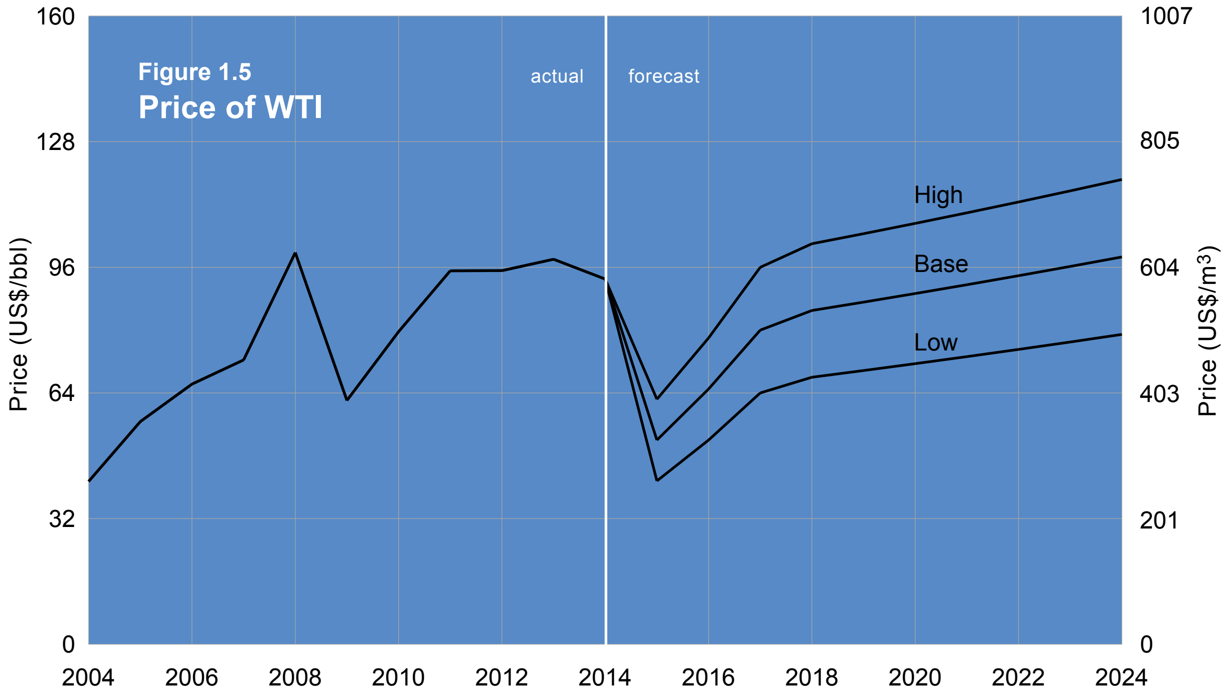


Figure 1.4
U.S. crude oil and natural gas daily production



The AER derives light crude oil prices at Edmonton, Alberta, as a function of WTI prices at Cushing. The WTI price is adjusted for transportation, crude oil quality, and the U.S./Canadian dollar exchange rate. Similarly, the Alberta heavy crude price at Edmonton is derived as a function of Western Canadian Select (WCS; provided in **Table 1.1**) and adjusted for transportation, crude oil quality, and exchange rate.[5] **Figure 1.6** shows historical prices and the AER's forecast for Alberta light-medium crude oil in Canadian dollars. Historical values for Alberta light-medium and Alberta heavy crude oil are shown in **Figure 1.7**. The heavy and light-medium differential is discussed below.

Table 1.2 compares 2013 and 2014 Alberta light-medium and heavy crude oil prices. In 2014, the price of light-medium crude oil averaged Cdn$89.40/bbl, up Cdn$1.63/bbl from 2013. The AER projects the price of light-medium crude oil to average Cdn$53.07/bbl in 2015, with a range of Cdn$40.56/bbl to Cdn$65.57/bbl.

As illustrated in **Figure 1.6**, the forecast price of light-medium crude oil is expected to increase throughout the forecast period and reach Cdn$106.48/bbl in 2024, ranging between Cdn$83.62/bbl to Cdn$129.33/bbl.

In 2014, Alberta light-medium crude oil priced at a discount relative to WTI due to competition from production from the Bakken play in the United States. In the short term, the Alberta light-medium forecast reflects the expectation that light crude oil production will continue to increase in North America. The long-term forecast for Alberta light-medium reflects the expectation that transportation constraints will be alleviated and demand for Canadian crudes will increase.

5 WCS is made up of existing western Canadian heavy conventional crude oil and Alberta crude bitumen blended with diluent.

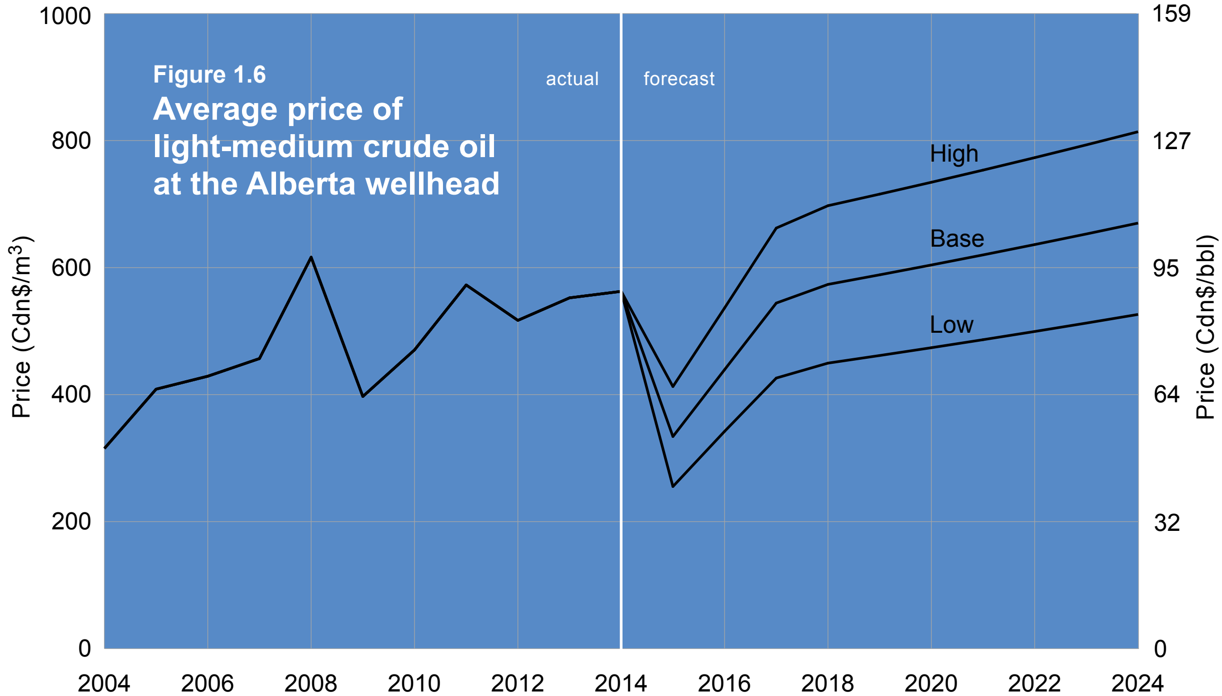


Figure 1.6
Average price of light-medium crude oil at the Alberta wellhead
actual
forecast
High
Base
Low
Price (Cdn$/m3)
Price (Cdn$/bbl)
0
200
400
600
800
1000
0
32
64
95
127
159
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024

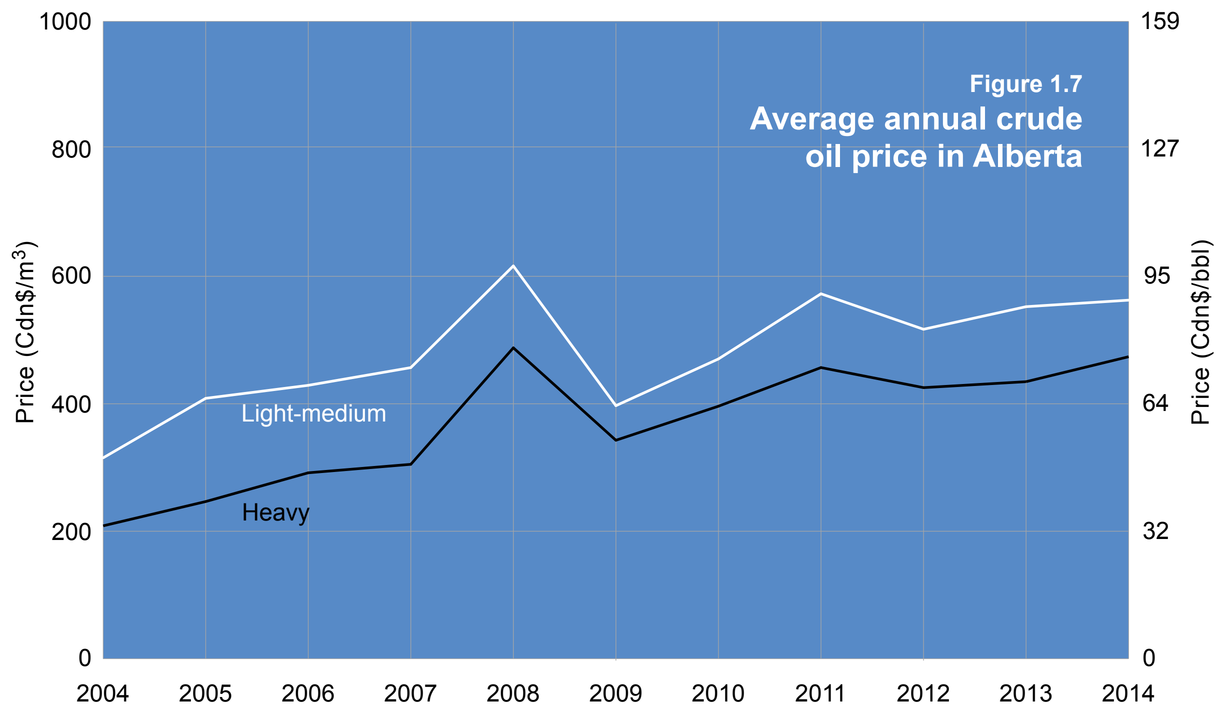


Figure 1.7
Average annual crude oil price in Alberta
Light-medium
Heavy
Price (Cdn$/m3)
Price (Cdn$/bbl)
0
200
400
600
800
1000
0
32
64
95
127
159
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014

Table 1.2 Alberta annual average wellhead crude oil prices[a]

	Average annual price (Cdn$/bbl)	
	2014	**2013**
Alberta light-medium crude oil price	89.40	87.77
Alberta heavy crude oil price	75.29	69.07

[a] Prices are from the AER's *ST3: Alberta Energy Resource Industries Monthly Statistics*, which reflect Alberta Petroleum Marketing Commission (APMC) prices. The APMC average price represents the value of the average Crown sales in the province in dollars per cubic metre with respect to royalty oil delivered to the APMC at the field delivery point to which the oil was required to be delivered in that month.

Figure 1.7 illustrates the average annual price of Alberta light-medium and heavy crude oil. The differential between Alberta heavy and light-medium crudes averaged Cdn$17.76/bbl, or 24.0 per cent, from 2004 to 2014. Most of this differential can be attributed to quality differences between heavy and light-medium crudes. The heavy and light-medium differential in 2014 averaged Cdn$14.11/bbl, or 15.8 per cent, compared with Cdn$18.70/bbl, or 21.3 per cent, in 2013. The heavy and light-medium differential narrowed in 2014 as heavy prices rose due to the increase in transportation capacity moving heavy crude to the United States.

Heavier Canadian crudes, such as WCS, have shown deeper discounts compared with other world benchmark prices. In the first quarter of 2014, WCS averaged US$74.59/bbl, trading at US$24.09/bbl or (33.0 per cent) under the price of WTI. As illustrated in **Figure 1.8**, throughout 2014, the discount between WCS and WTI narrowed in absolute terms, averaging US$16.18/bbl in December 2014. However, in percentage terms, it remained wide and averaged 37.5 per cent. Heavy Canadian crudes have been discounted due to concerns of oversupply and pipeline constraints.

Crude oil production in Alberta, after it meets Alberta and Canadian refinery demand, is exported to the United States. The Petroleum Administration for Defence Districts (PADDs) 2 and 4 in the United States are the largest importers of Alberta heavy crude and bitumen, with a combined total refinery capacity of 4440 10^3 bbl/d (706 10^3 m^3/d). Increased heavy oil upgrading capabilities at the BP America Inc. (BP) refinery at Whiting, Indiana, as well as other refinery conversion projects, will increase PADD 2 and PADD 4 capacities to take on increasing amounts of Alberta heavier crudes.

Although no new refineries have been built since the 1970s, the total refinery capacity in the United States increased slightly during the 1990s and 2000s because of debottlenecking and expanding existing refineries. This trend has continued, with U.S. refining capacity increasing only by 1 per cent over 2014, according to the EIA.

Two new refineries have been announced in the United States, one in North Dakota and one in Utah. The construction of a 20 10^3 bbl/d refinery in North Dakota is complete, with commercial production of diesel fuel and other products expected in the first quarter of 2015. Another refinery with a 10 10^3 bbl/d capacity in Utah is expected to be operational in 2016.

Additional pipeline infrastructure is important for transporting the increasing U.S. and Alberta heavy crude exports to markets in the United States and Asia. With expected increases in both upgraded and nonupgraded bitumen supply over the forecast period, adequate incremental pipeline capacity is essential for transporting growing volumes to market. Pipeline projects, both proposed and announced, to help the movement of crude oil are discussed in **Section 9.1.1**.

Figure 1.9 gives information on U.S. refineries by PADD. PADD 3 has the largest refinery capacity in the United States, with 56 operating refineries and a net crude oil distillation capacity of 9.2 10^6 bbl/d (1454.7 10^3 m^3/d). PADD 3 was not previously considered the most likely market for Alberta crude oil because of inadequate pipeline infrastructure and its proximity to Mexican and Venezuelan crude oil production. However, traditional non-Canadian crude oil imports to PADD 3 have been on the decline, suggesting a significant market opportunity for Alberta heavy crude oil producers. Projects such as TransCanada's proposed Keystone XL project would increase pipeline capacity to the area.

1.1.4 North American Natural Gas Prices

While North American crude oil prices have historically tracked international prices, natural gas prices in North America reflect continental supply and demand, with little influence from the global gas market other than that of LNG imports. As Alberta natural gas prices are heavily influenced by the Henry Hub U.S. market price, the Alberta price forecast for natural gas is derived from the Henry Hub price, taking into account transportation differentials and the U.S./Canadian dollar exchange rate.

Figure 1.10 shows the historical yearly average price of AECO-C and Alberta natural gas at the plant gate (also known as the Alberta reference price). In comparison to the previous two years, prices were higher in 2014, averaging Cdn$4.21/GJ and Cdn$4.00/GJ, respectively. This compared to Cdn$3.03/GJ and Cdn$2.83/GJ in 2013, a 39 per cent and 41 per cent increase, respectively. In 2014, U.S. natural gas prices at Henry Hub increased by about 15 per cent compared with 2013 levels.

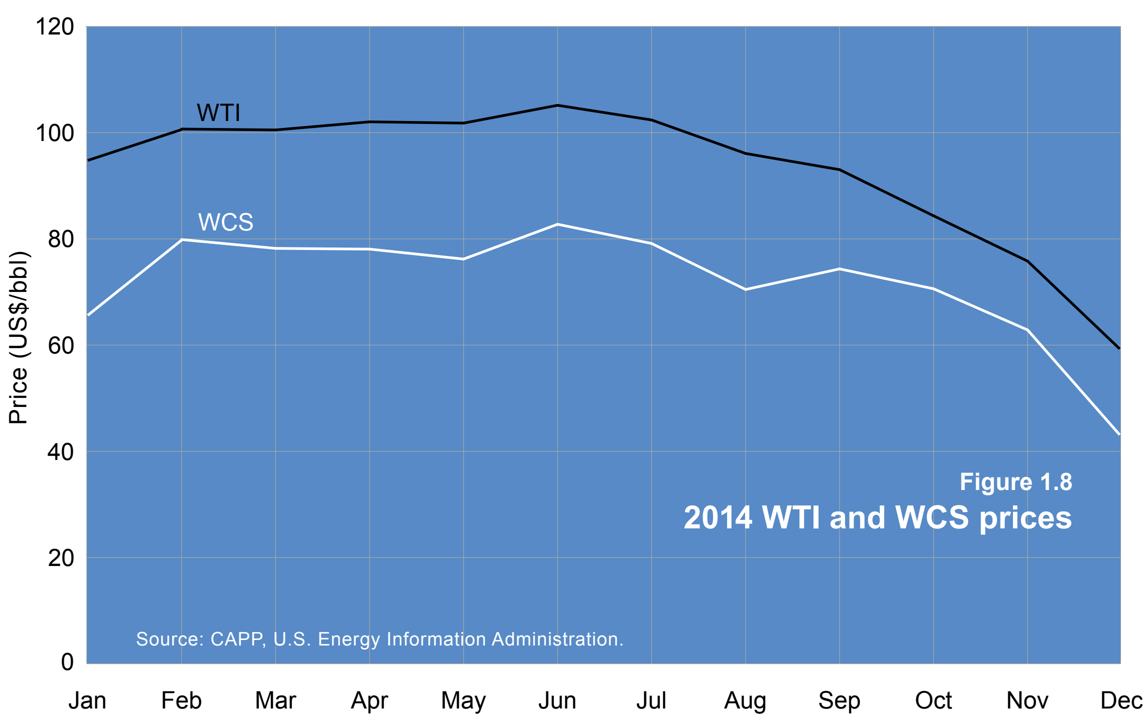
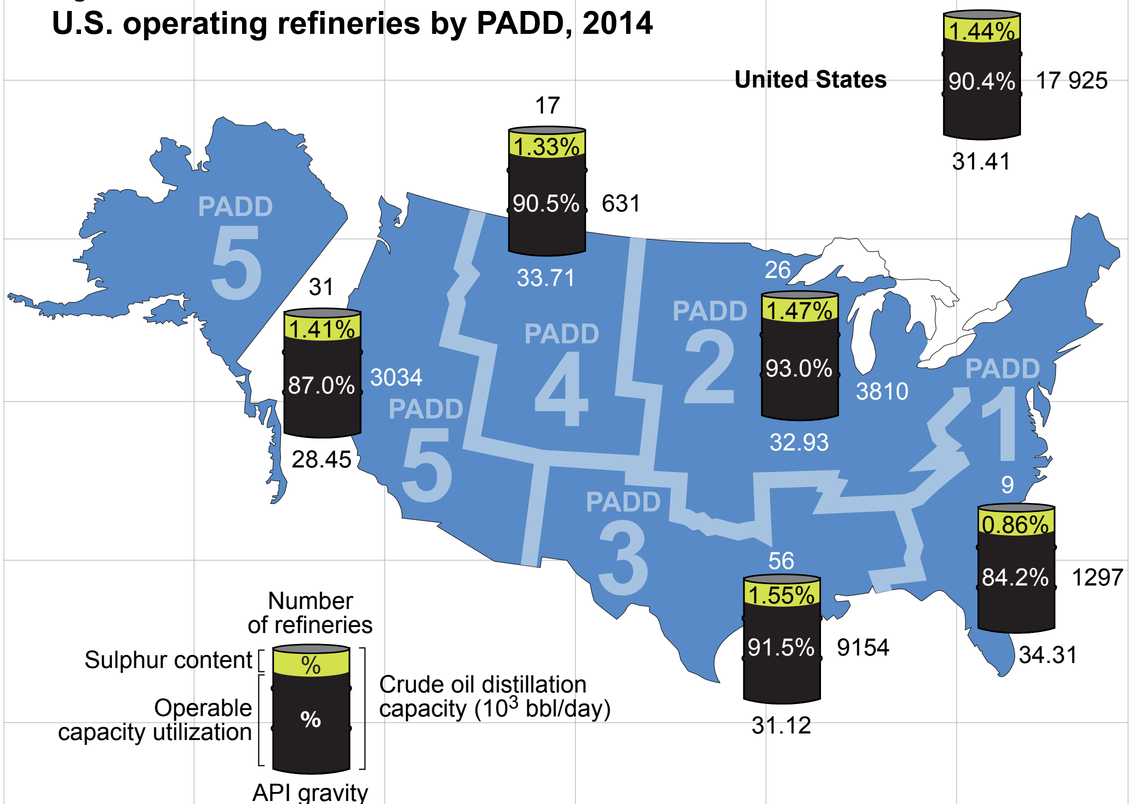


Figure 1.8
2014 WTI and WCS prices

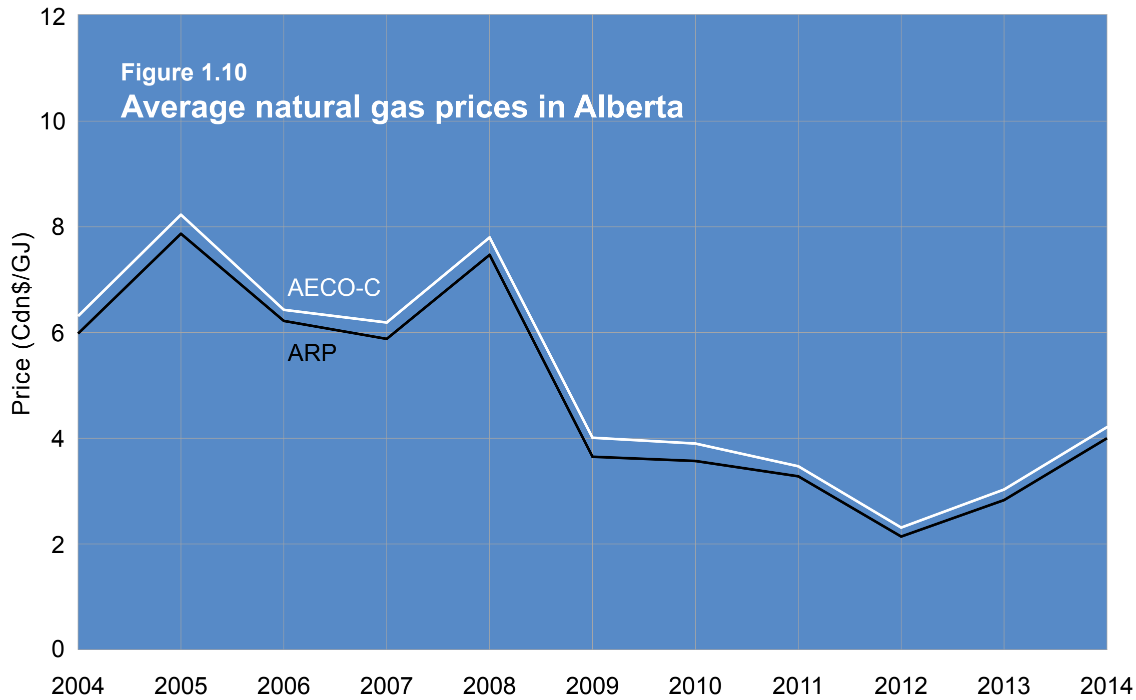
Figure 1.9
U.S. operating refineries by PADD, 2014



Source: U.S. Energy Information Agency.
Number of operating refineries as of March 17, 2015. Data for the year 2014.
Sulphur content and API gravity are weighted averages.

In 2014, the cold winter experienced across much of North America caused the AECO-C natural gas price to average Cdn$5.64/GJ in February, as low temperatures prompted record withdrawals from storage, while at the same time production struggled to keep pace with record demand. Prices eased over the next several months, but still remained elevated, reflecting the concern that producers might not be able to rebuild inventories for the next winter. However, this encouraged companies to drill more, resulting in record levels of storage injections, and the AECO-C natural gas price fell below Cdn$4.00/GJ in August. October's unseasonably warm weather triggered storage increases, and the average monthly price fell to Cdn$3.80/GJ. A sudden cold-snap in November put some upwards pressure on prices, but by the end of the year the natural gas spot price had fallen, as warm winter weather undercut heating demand prompting storage levels to continue to increase.

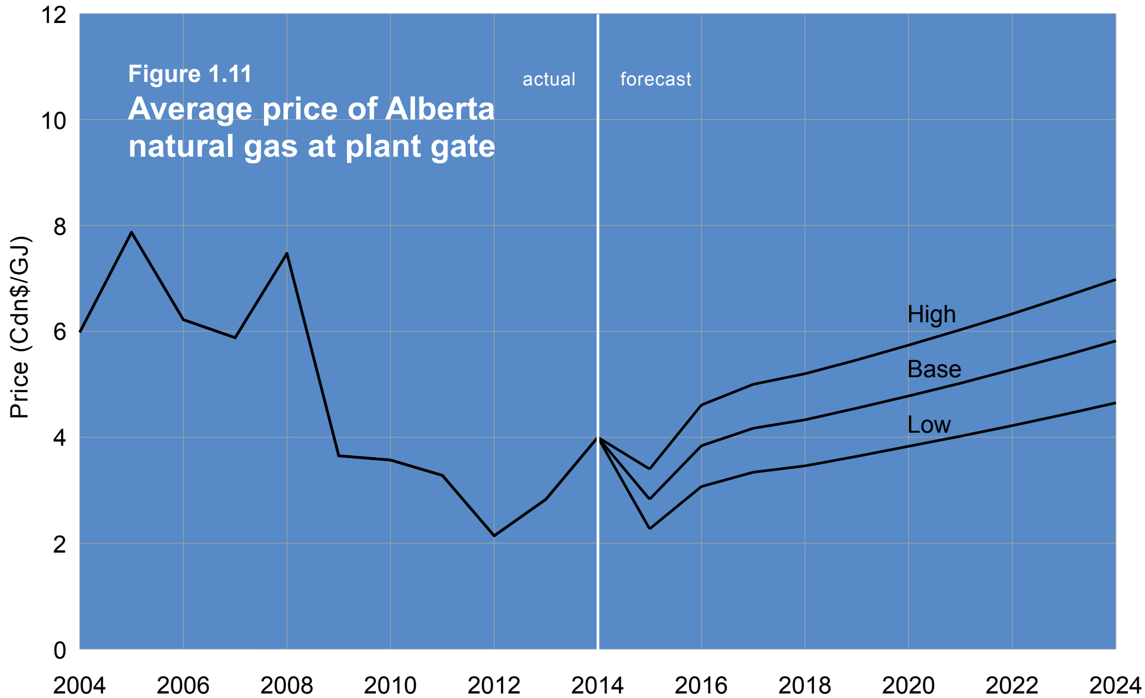
Figure 1.11 shows the historical and forecasted average price of Alberta natural gas at the plant gate. The AER projects a base price of Cdn$2.83/GJ for natural gas at the Alberta plant gate, with lower and upper bands of Cdn$2.27/GJ and Cdn$3.40/GJ, due to anticipated weak demand. Over the forecast period, the price of natural gas is projected to increase and reach an average of Cdn$5.82/GJ by 2024, ranging from Cdn$4.65/GJ to Cdn$6.98/GJ. The forecast in this report is slightly lower than last year's forecast.



The forecast assumes that gas production in the United States will continue to increase, keeping prices low in the short and medium term. Longer term, demand growth for natural gas is forecast to occur as environmental policy aimed at reducing emissions from coal-fired electricity generation prompts a switch to natural gas. In addition, liquefied natural gas (LNG) export projects are expected to add additional demand.

Increased U.S. natural gas production has resulted in low natural gas prices, as shale gas production has more than offset production declines from conventional resources. As illustrated previously in **Figure 1.4**, natural gas production in the United States began to increase significantly, following a four-year period of decline between 2001 and 2005. Total U.S. marketed gas production was 74.7 billion cubic feet per day (Bcf/d) (2.1 billion [10^9] m^3/d) in 2014, a 44.0 per cent increase from 2005 levels. Projects to convert some of the LNG regasification terminals to liquefaction terminals are under construction in the United States to enable exports of domestic natural gas supplies to offshore markets. In addition, new LNG export terminals have been proposed and approved in both the United States and Canada.

In Canada, more than a dozen LNG export projects have been proposed on both the east and west coasts as Canadian natural gas producers reach for new gas markets in Asia. Under increased competition from U.S. shale gas production, U.S. natural gas imports from Canada have fallen by 30 per cent since 2007. Asian markets, with LNG prices indexed to crude oil prices, provide an attractive alternative to U.S. exports. In 2014, the National Energy Board (NEB) issued export licences for Kitimat LNG Operating General Partnership, LNG Canada Development Inc., and Pacific NorthWest LNG Ltd. and approved three other projects to export LNG from the B.C. coast to Asia-Pacific markets.



The Alberta price ratio of gas to light-medium oil, on an energy content basis, averaged 0.41 from 2004 to 2014.[6] In 2014, the price ratio averaged 0.27, compared with 0.20 in 2013. Over the forecast period, the gas-to-oil price ratio is projected to average 0.31 as North American gas prices are projected to increase slowly relative to crude oil prices.

1.2 Oil and Gas Drilling and Completion Costs in Alberta

The Petroleum Services Association of Canada (PSAC) provides cost estimates for typical oil and gas wells for the upcoming drilling season. PSAC defines a typical oil and gas well as a well that reflects the most common well type to be drilled in 2015 in western Canada. The cost estimates in **Figure 1.12** were obtained from PSAC's *2015 Well Cost Study*. **Table 1.3** outlines the average well depth for the areas that had drilling in 2014, a major contributor to drilling costs. Many other factors also influence well costs, including the economic environment, the type of commodity produced, the type of well (development versus exploratory), surface conditions, the type of production (sweet versus sour), drilling programs, well location, nearby infrastructure, and completion method.

As illustrated in **Figure 1.12**, the estimated cost to drill and complete a typical oil well increased in 2014, relative to 2013, by an average 4.3 per cent. The estimated cost of drilling and completing a typical oil well in the winter of 2014–2015 ranged from as low as $0.84 million in PSAC Area 4 (East-Central Alberta) to as high as $2.49 million in PSAC Area 5 (Central Alberta). Average gas well drilling and completion costs also increased in

[6] If consumers were to pay the same price for a unit of gas as they would for a smaller unit of light-medium crude oil containing the same energy content as the unit of gas, the gas to light-medium price ratio would be 1.00 (parity being achieved). However, for a variety of reasons, oil is intrinsically valued higher than gas, and the price ratio is often near or below 0.50.

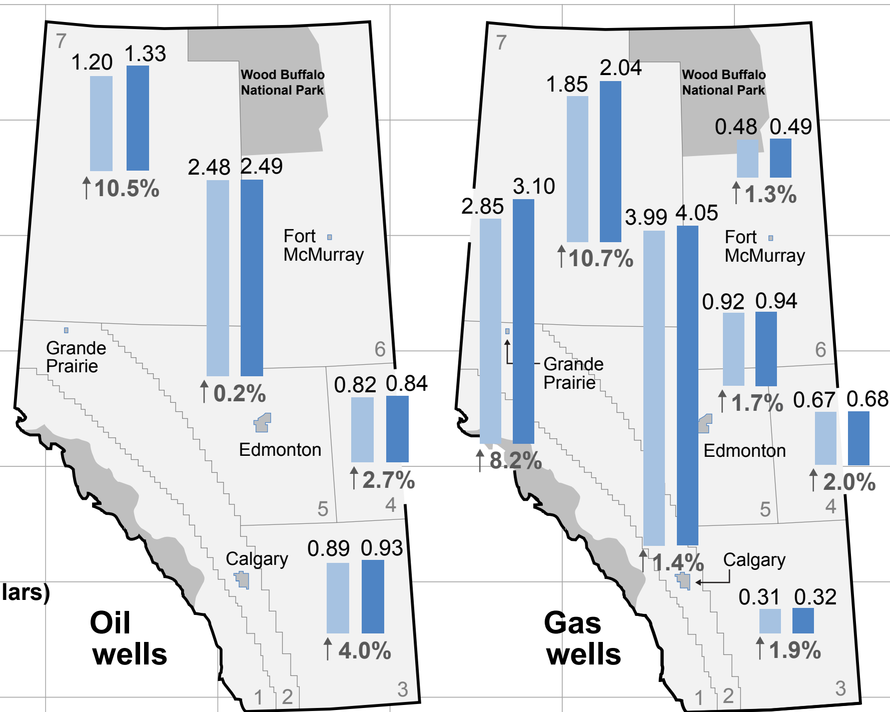


Figure 1.12
Alberta well cost estimations, by PSAC area
(millions of current dollars)

Drilling, casing, and completion cost estimates (PSAC November 2013 and November 2014 well cost studies).

Table 1.3 Alberta average well depths by PSAC area, 2014 (m)[a]

	Area 1	Area 2	Area 3	Area 4	Area 5	Area 6	Area 7
Gas wells							
Horizontal	4 616	4 388	2 580	1 763	3 569	1 217	4 235
Vertical	3 920	3 343	983	918	797	270	1 926
Oil wells							
Horizontal	3 335	3 634	2 356	1 818	2 812	1 501	3 131
Vertical	6 437	1 962	1 394	712	1 675	621	1 404

[a] PSAC defines the areas in Alberta as AB1, AB2, etc.; however, they are referred to as Area 1, Area 2, etc. in this report. The PSAC area map is located in **Appendix A.2**.

2014, relative to 2013, by an average 3.9 per cent. Estimated costs to drill and complete a typical gas well in the winter of 2014–2015 were highest in PSAC Area 2 (Foothills Front) at over $4.05 million and lowest in PSAC Area 3 (Southeastern Alberta) at $0.32 million to drill and complete.

1.3 Economic Performance

1.3.1 Alberta and Canada

Figure 1.13 depicts the historical performance of major economic indicators for Alberta and Canada. Alberta real gross domestic product (GDP) growth has mostly outperformed Canadian real GDP growth over the past decade, particularly from 2004 to 2006. Average Alberta GDP growth from 2004 to 2014 was 3.4 per cent, compared with the Canadian average of 2.0 per cent. Alberta real GDP is estimated to have increased by 3.6 per cent in 2014, compared with 3.8 per cent in 2013. Over the same period, the unemployment rate in Alberta averaged 4.7 per cent while the Canadian unemployment rate averaged 7.1 per cent.

The higher growth and employment levels in Alberta put pressure on the Alberta economy, which resulted in higher levels of inflation. Since 2004, inflation in Alberta has averaged 2.2 per cent per year, while Canadian inflation has averaged 1.8 per cent. In 2014, Alberta inflation averaged 2.6 per cent compared to 1.4 per cent in 2013. The main reason inflation was up in 2014 compared with 2013 was due to the increase in energy prices at the beginning of the year in addition to pressures from food and housing prices.

Figure 1.14 illustrates the historical performance of the U.S./Canadian dollar exchange rate between 2004 and 2014. The exchange rate is an economic parameter that affects both the Canadian and Alberta economies.

The U.S./Canadian dollar exchange rate averaged US$0.91 in 2014, compared with US$0.97 in 2013. This rate is projected to average US$0.79 in 2015, increase to US$0.80 in 2016, and then rise to and remain at US$0.82 for the rest of the forecast period. This forecast is lower than the 2014 forecast.

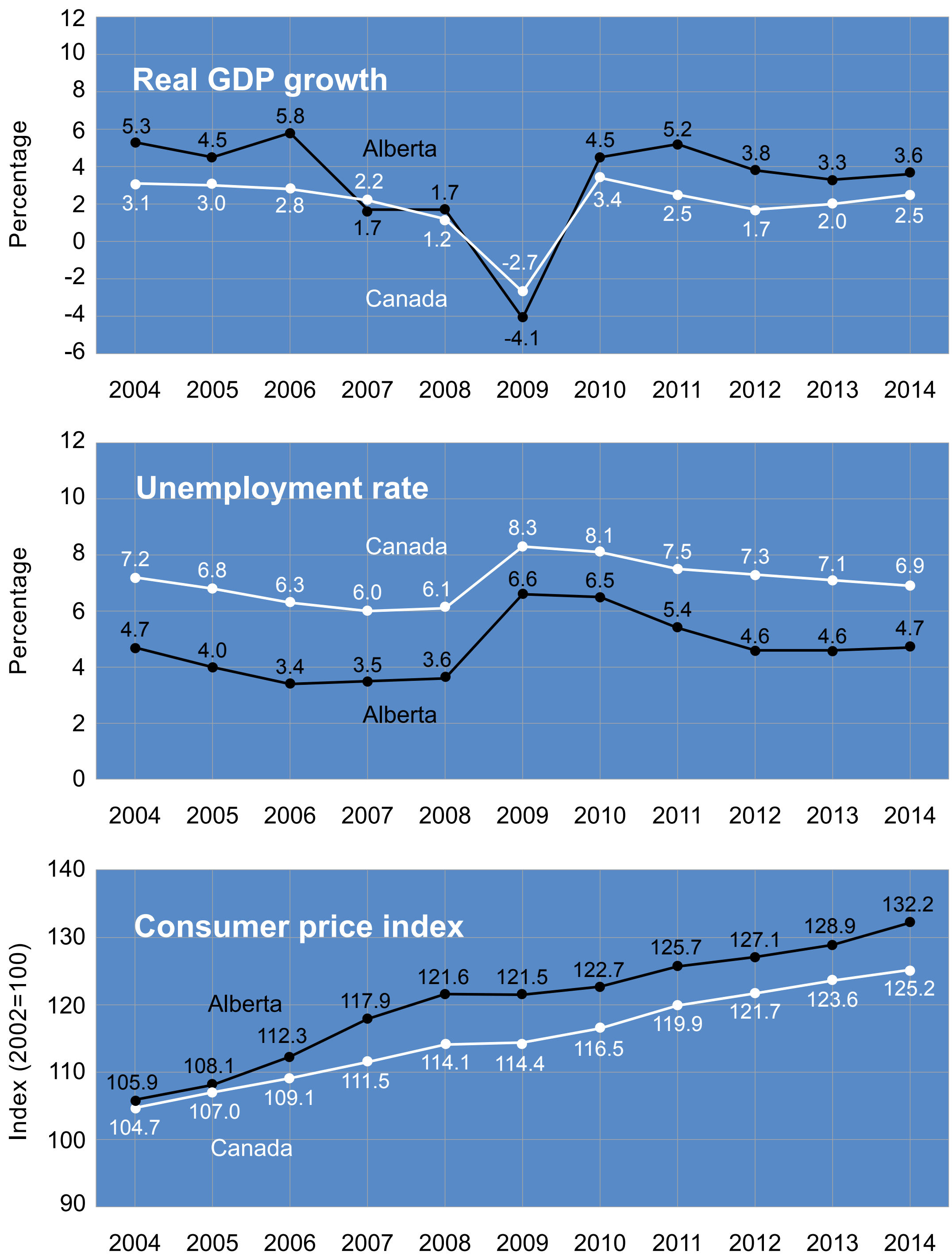
In early 2015, the Bank of Canada cut the overnight lending rate by 25 basis points to 0.75 per cent in response to the recent sharp drop in oil prices, stating that the oil price shock increased both downside risks to the inflation profile and financial stability.[7] The central bank said in a statement that the cut is to provide insurance against these risks and support the adjustments needed to return the economy to full output.

1.3.2 Alberta Economic Outlook

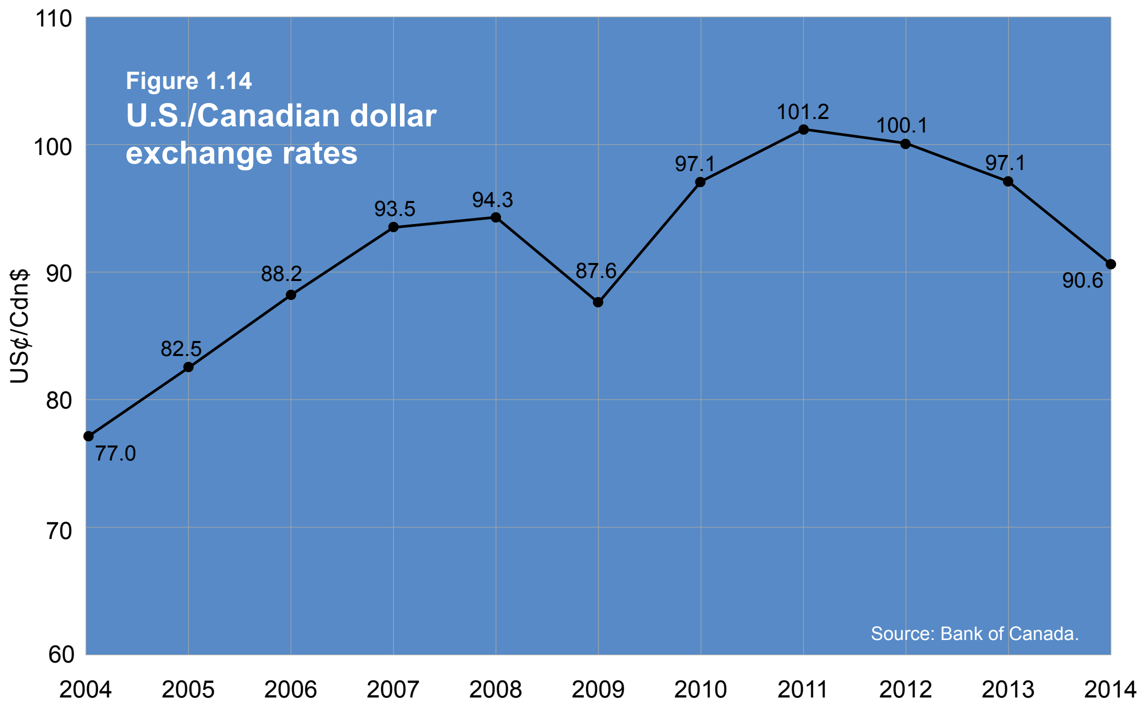
The expansion of Alberta's economy is expected to slow in 2015, after five years of high growth. The slowdown is a result of significantly weaker crude oil prices, which fell more than 50 per cent in the second half of 2014. Weaker oil prices are expected to dampen economic activity as energy companies pull back on investment and look for strategies to reduce costs.

[7] The overnight lending rate, also known as the key interest rate or key policy rate, is used by the Bank of Canada to carry out monetary policy and influence short-term interest rates.

Figure 1.13
Alberta and Canada economic indicators



Source: Statistics Canada.



The AER forecast of Alberta real GDP and other economic indicators is shown in **Table 1.4**. Real GDP is expected to increase by 0.5 per cent in 2015, by 1.8 per cent in 2016, and by 3.0 per cent each year thereafter for the remainder of the forecast period from 2017 to 2024, based on expected strong hydrocarbon development and exports.

The AER estimates that oil sands capital expenditures increased to $33 billion in 2014, compared with $31 billion in 2013. Investment is predicted to decrease to $25 billion in 2015 then increase slightly in 2016 to $26 billion. In late 2014 and early 2015, a number of oil sands companies announced that they were cutting their capital budgets and delaying the development of upcoming projects because of the decline in crude oil prices.

Between 2009 and 2014, conventional oil and gas expenditures increased from a level of $12 billion to reach an estimated $23 billion in 2014 as industry drilled fewer, but more capital-intensive, horizontal wells. Investment in conventional oil and gas is expected to decrease significantly in 2015 because of weak crude oil prices, but recover after 2015 as crude oil prices strengthen over the forecast period and as producers continue to use capital-intensive technologies.

Figure 1.15 shows the historical and projected investment in Alberta's conventional oil and gas industry and in the oil sands industry.[8] The decline in capital expenditures in 2015 is expected to be similar to the decline that happened in 2009; however, the rebound that occurred in 2010 is not expected as capital expenditures are not projected to reach pre-2015 levels over the forecast period.

[8] Historical statistics obtained from CAPP's *Statistical Handbook* (2013 data). Capital expenditures for 2014 are estimates.

Table 1.4 Major Alberta economic indicators, 2014–2024 (%)

	2014	2015	2016	2017–2024[a]
Real GDP growth	3.6	0.5	1.8	3.0
Population growth	2.9	2.2	2.0	1.8
Inflation rate	2.6	1.0	2.0	2.2
Unemployment rate	4.7	5.5	5.2	4.7

[a] Average over 2017–2024.

The AER's forecast of industry capital expenditures for oil sands and conventional oil and gas is consistent with the forecasts put forward in this report.

As shown in **Figure 1.15**, expenditures related to the oil sands are projected to increase by the middle of the decade to fulfill the anticipated increases in upgraded and nonupgraded bitumen production. Nonupgraded bitumen production is expected to increase at an average annual rate of 9 per cent. Upgraded bitumen production is projected to increase at an average annual rate of 3 per cent. Combined with conventional oil and gas expenditures, total oil and gas investment is expected to be similar to the level of capital spending experienced during 2007–2008.

The value of Alberta's energy resource production for 2010 to 2014 is shown in **Figure 1.16**. In 2014, the total value of production increased by 16.1 per cent from 2013. The value of upgraded and nonupgraded bitumen production has significantly exceeded the value of natural gas production, a trend that is expected to continue throughout the forecast period. Since 2010, the value of upgraded and nonupgraded bitumen production has

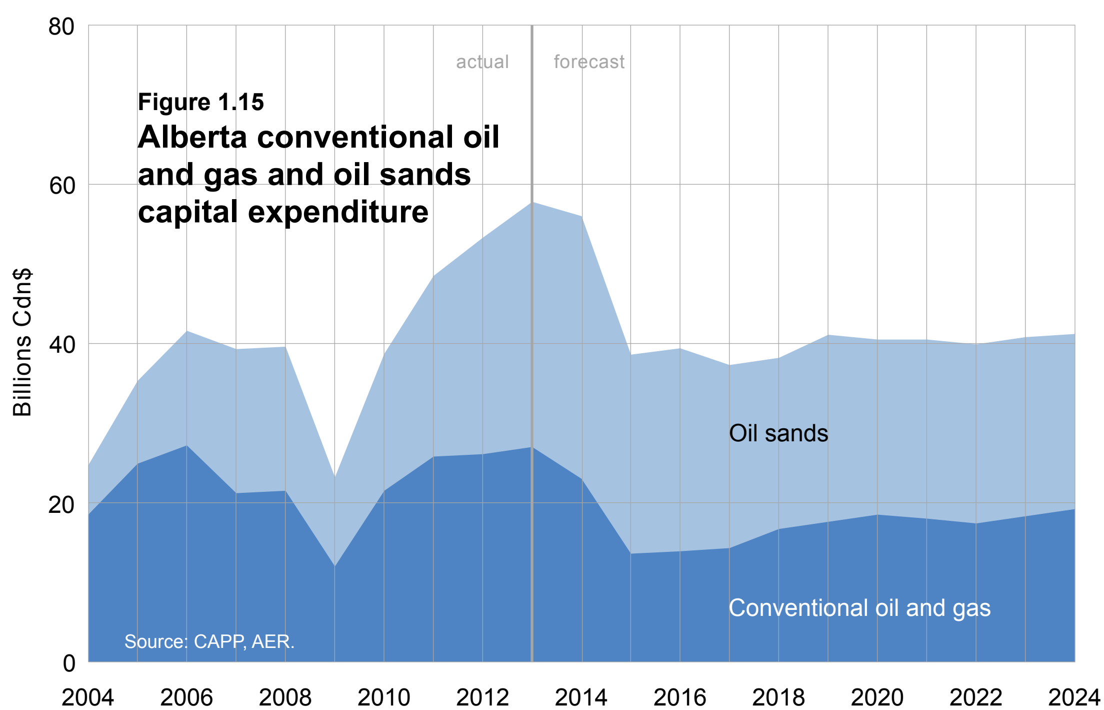


Figure 1.15
Alberta conventional oil and gas and oil sands capital expenditure

Source: CAPP, AER.

increased by 74.4 per cent, whereas the value of natural gas production has remained flat. In 2014, combined upgraded and nonupgraded bitumen revenues were 50.3 per cent greater than the combined revenues from conventional gas, conventional crude oil, natural gas liquids, and sulphur.

The total economic value of Alberta's energy resource production for 2014 to 2024 is shown in **Table 1.5**. Production from upgraded and nonupgraded bitumen will more than offset the anticipated decline in conventional production, increasing from 60.1 per cent of total revenues in 2014 to 72.6 per cent of total annual revenues by 2024.

Based on the projected price and production forecasts, after a slowdown in 2015, investment in mining, upgrading, and in situ bitumen projects are forecast to continue to drive Alberta's production, export growth, and the overall Alberta economy. In turn, Alberta's economic growth is projected to continue to contribute strongly to Canada's economic growth going forward.

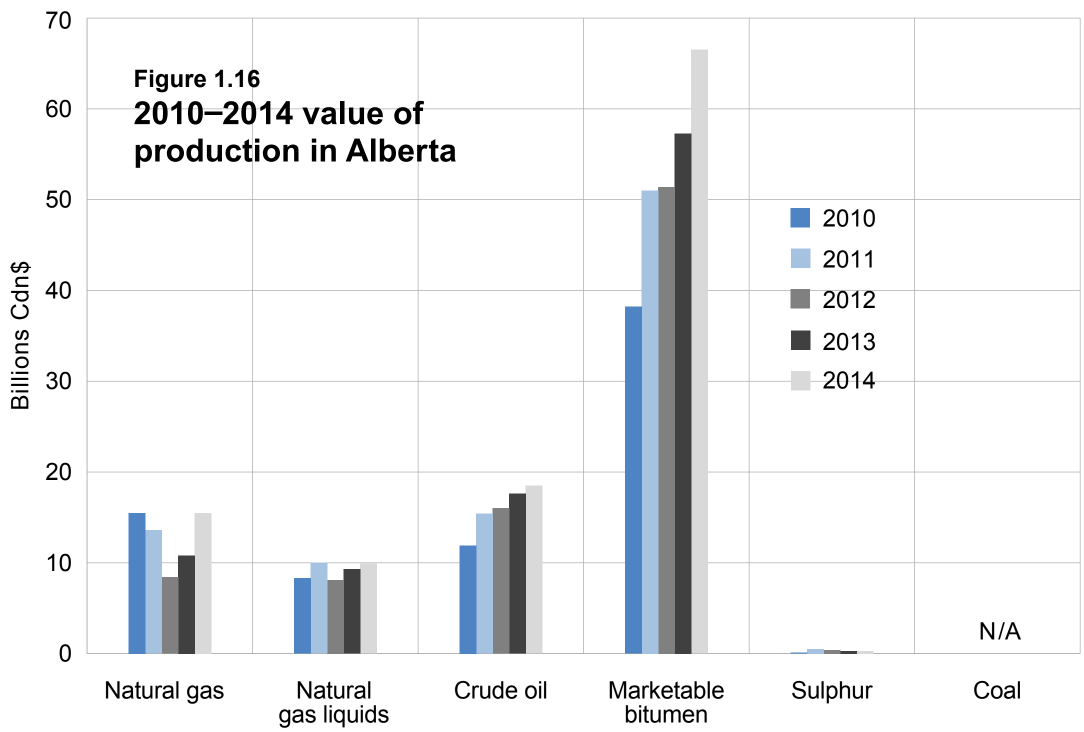


Table 1.5 Value of annual Alberta energy resource production (millions of current dollars)

	2014	2015[a]	2016[a]	2024[a]
Conventional crude oil	18 478	10 246	13 214	16 978
Nonupgraded bitumen	31 615	19 871	28 025	76 296
Upgraded bitumen	34 920	21 238	30 046	53 968
Marketable gas	15 537	10 758	14 642	19 957
Natural gas liquids	9 871	6 037	7 888	11 799
Sulphur	344	331	343	363
Coal[b]	n/a	n/a	n/a	n/a
Total	**110 765**	**68 481**	**94 158**	**179 361**

[a] Values calculated from the AER's annual average price and production forecasts; columns may not add up due to rounding.

[b] Not available (n/a)—There are no publicly available coal prices in Alberta. However, it is believed that coal's value is more similar to sulphur than the other commodities listed in this table.

HIGHLIGHTS

A discussion of the geological framework of the Western Canada Sedimentary Basin and Alberta's petroleum systems is given.

A discussion on Alberta's Table of Formations and how plays are beginning to be used to define petroleum accumulations is detailed.

The methods the AER uses to estimate resources and determine reserves are described.

The reserves framework employed in the report is explained.

2 RESOURCE ENDOWMENT

Of Alberta's many natural resources, this report focuses on energy resources—namely, petroleum hydrocarbons and coal. The AER performs ongoing appraisals of Alberta's energy resources primarily to monitor extraction and assure Albertans that energy resources under development are being conserved and not being wasted or damaged. The AER also uses the information from its resource appraisals in its authorization, compliance, and closure and liability functions. The information is also used by the Government of Alberta to develop policies and for regional land-use planning, and by the energy industry to help evaluate investment opportunities in Alberta.

The appraisal of resources is of particular importance in Alberta, where the vast majority of energy resources are publicly owned, with stewardship responsibilities vested in the Crown and its agencies, like the AER. Private enterprises bid on Crown leases through mineral auctions for the opportunity to explore for and develop the resources. Successful discovery and commercial extraction returns royalties, taxes, and other economic benefits to Albertans. The AER's mandate is to balance orderly development of these leases with government policies to assure water conservation, public safety, environmental protection, and the wise use of public lands.

The major components of resource appraisal are geological survey, resource estimation, and reserve determination—all of which are done in a framework to give consistent year-to-year comparisons of energy development in Alberta. The AER works to continuously improve upon this framework to reflect the changing nature of energy development and advances in scientific and engineering knowledge about energy resources. Some of the changes in progress at the AER during 2014 are discussed below.

2.1 Geological Framework of Alberta[1]

The geology of Alberta consists of a northeast-thinning wedge of sedimentary rock lying overtop a crystalline basement of igneous and metamorphic rock of Precambrian age that forms the ancient core of the modern North American continent.[2] The thickness of the sedimentary wedge tapers from a thick package

[1] The *Geological Atlas of the Western Canada Sedimentary Basin* contains a full description of Alberta's geological history and forms the basis for the summary in this section. The atlas is available through the AER's Alberta Geological Survey, a co-sponsor of the atlas, on its website, www.ags.gov.ab.ca.

[2] The crystalline basement forms the ancient continent of Laurentia (also known as the North American craton) and is commonly referred to as the Canadian or Precambrian Shield where

thousands of metres in eastern British Columbia (B.C.) to zero in northeastern Alberta where the crystalline basement is exposed as part of the Canadian Shield. Sedimentary rocks also extend into Saskatchewan, Manitoba, the Northwest Territories, and the United States.

2.1.1 Western Canada Sedimentary Basin

Within Alberta, the sedimentary wedge comprises three thick packages of rock most simply described as a carbonate succession sandwiched between two clastic successions. The lower clastic succession is restricted to the Rocky Mountains. It is composed of a thick package of metamorphic quartzite and slate rocks of Precambrian age and overlying sedimentary strata (layers of rock) of Cambrian to Ordovician age. The middle carbonate succession is composed mainly of limestones, dolostones, and evaporites of Devonian to Mississippian age. The upper clastic succession is Triassic to Tertiary in age.

Both the middle carbonate and the upper clastic successions cover most of Alberta. Just beneath the modern land surface is a major unconformity that separates the youngest bedrock from gravels, thick glacial deposits, and modern alluvium.

The initial continental margin and later structural trough that received sediments that comprise these three thick packages are collectively known as the Western Canada Sedimentary Basin (WCSB). The WCSB is often divided into regional basinal and sub-basinal elements, including the Alberta Basin, the Williston Basin, and the Liard/Horn River Basin, as shown on **Figure 2.1**.

The geological origin and structure of Alberta's strata ultimately determine the type and extent of Alberta's energy resources. The overall geological history of Alberta falls into two main phases:

- Phase I lasted from about 1.5 billion years ago to about 170 million years ago. It was characterized first by deposition in a shallow sea lying along the passive continental margin of the proto-Pacific ocean.[3] This was followed by deposition within a shallow, interior continental seaway. This seaway marked the formation of an intracontinental basin, formed indirectly in association with uplift and mountain building far to the southwest of Alberta. The lower clastic and middle carbonate successions were deposited during phase I.
- Phase II started about 170 million years ago and continues to the present day. It is characterized by uplift and structural deformation, which formed the Rocky Mountains and mountain ranges farther west. Loading of the mountains onto the crust caused the shallow seaway of phase I to deepen into a depositional trough called a foreland basin. Sediments from the rising mountains were shed eastward into the basin, gradually filling it in and causing the seas to retreat. Uplift abated about 55 million years ago, and the Alberta basin has undergone erosion ever since, with the exception of deposition related to glacial advances and retreats over the last two million years. The upper clastic succession was deposited during phase II. These events are shown in **Figure 2.2**.

it outcrops in Canada. Laurentia was created almost two billion years ago by the amalgamation of older continents; some from the Earth's original crust that formed about four billion years ago.

[3] During phase I, the continental mass (Laurentia) alternated between being a separate continent and existing as part of larger "supercontinents."

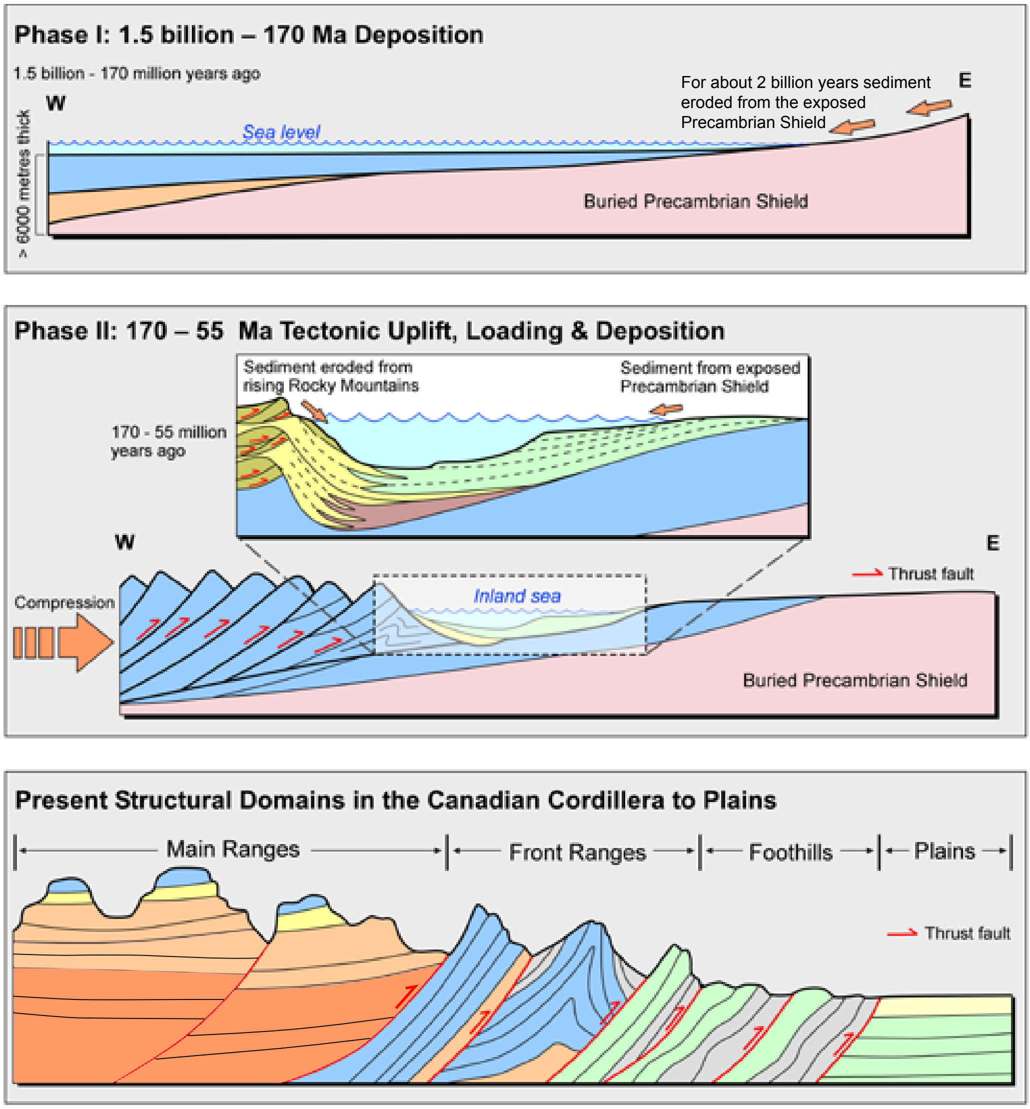
Figure 2.1
Basinal elements of the Western Canada Sedimentary Basin

The geological record of events in phases I and II is preserved in the strata of the WCSB. A simplified version of Alberta's strata is shown in **Figure 2.3**. The stratigraphy is formalized in the AER's official Table of Formations, available on the AER's website. The AER's Alberta Geological Survey (AGS) made improvements and corrections to the Table of Formations in 2014, to be published in 2015. The Table of Formations is also being brought into better compliance with the North American Stratigraphic Code. To help the adoption of these forthcoming changes, the AGS will also be updating the Alberta components of the Lexicon of Canadian Stratigraphy, which is maintained by Natural Resources Canada.

2.1.2 Alberta's Petroleum Systems

Petroleum is a naturally occurring organic mixture consisting predominantly of chain and ring molecules of carbon and hydrogen, with varying amounts of sulphur, nitrogen, and oxygen as impurities. Petroleum forms underground by the action of heat and pressure over millions of years on buried organic matter that originated as dead algal, plankton, and plant remains. Rock units sufficiently rich in organic matter to generate petroleum during burial are called source rocks. After petroleum generation begins, the petroleum is driven from the source rock and migrates along permeable strata and fractures until it is trapped by favourable geological configurations of low-permeability rock or escapes to the surface.

Figure 2.2
Geological evolution of Alberta



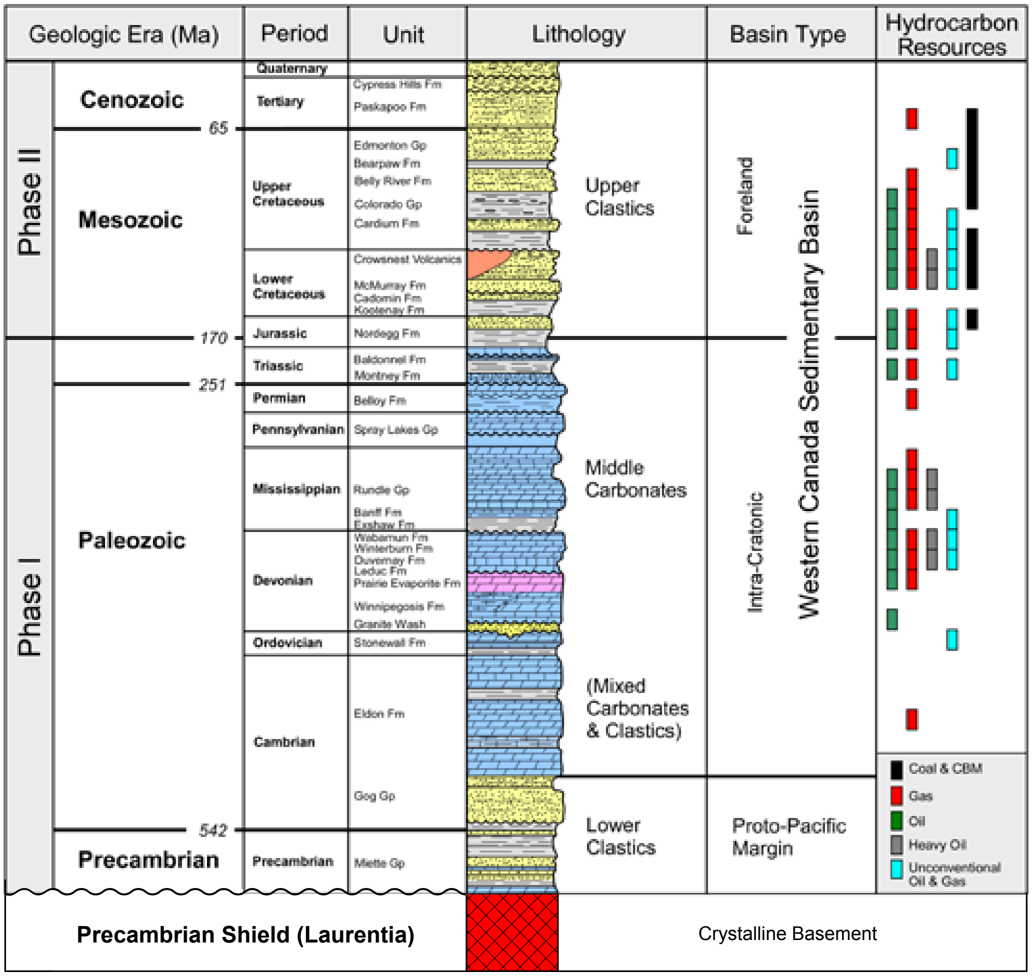
* Drawings not to scale.

Not all of the petroleum generated in source rocks will migrate; much is left within the source beds themselves. Many of these source rocks are shales and are the targets of many recent unconventional plays.

Coal, which is formed by heat and pressure acting on buried plant material, is made of over 50 per cent organic matter and is normally recovered as a commodity for its energy content. However, it can also be a special type of source rock as coalbeds can produce substantial amounts of methane.

The linked assemblage of source rock, migration routes, and ultimate traps is called a petroleum system. The Alberta Basin component of the WCSB contains at least eight petroleum systems associated with the following major source rocks:

Figure 2.3
Generalized stratigraphic column of Alberta



- Middle Devonian System – sourced by basinal marine laminites of the Keg River/Winnipegosis formations
- Upper Devonian System – sourced by basinal marine laminites of the Leduc-equivalent Duvernay and Cooking Lake–equivalent Majeau Lake formations
- Upper Devonian System – sourced by basinal laminites of the Cynthia Member of the Nisku Group
- Uppermost Devonian and lowermost Mississippian System – sourced by the basinwide marine mudstones of the Exshaw Formation[4]
- Middle Triassic System – sourced by the marine phosphatic siltstones at the base of the Doig Formation

[4] The Exshaw Formation of the Alberta Basin is generally equivalent to the lower Bakken Formation found within the Williston Basin centered in North Dakota.

- Lower Jurassic System – sourced by the marine lime muds of the Nordegg (Gordondale) Member of the Fernie Group
- Lower Cretaceous System – sourced by the continental coals and carbonaceous shales of the Mannville Group
- Upper Cretaceous System – sourced by the marine mudstones of the Colorado Group, principally the First and Second White Speckled Shales and the Fish Scales Zone

The Exshaw, Nordegg, and Duvernay source rocks are thought to have supplied most of the hydrocarbons in the Alberta Basin, and hydrocarbon accumulations within upper systems can be sourced from lower systems. For example, a likely source for the Lower Cretaceous crude bitumen deposits is the Lower Mississippian Exshaw Formation.

Conventional oil and gas pools are found throughout the middle carbonate and upper clastic successions. Little oil and gas is known to occur in the lower clastic succession, and the crystalline basement has none. Coals and coalbed methane (CBM) are found within the Jurassic-, Cretaceous-, and Tertiary-age portions of the upper clastic succession. Heavy oil pools and crude bitumen[5] deposits occur mostly in Cretaceous-age strata at the shallow updip edge of the Alberta Basin, near the contact of the sedimentary successions with the underlying crystalline rocks of the Precambrian basement. There is also bitumen in the middle carbonate succession directly underneath.

In addition to these accumulations, there is widespread biogenic generation of methane in the shallow subsurface, mostly found in unconsolidated glacial deposits and shallow coal-bearing bedrock units. This gas is pervasive but does not occur in commercial quantities and sometimes is a geological hazard in shallow water wells in Alberta.

2.1.3 Energy Resource Occurrences – Plays, Deposits, and Pools

Estimates of potential volumes of hydrocarbon generation and migration can be quantified for petroleum systems through a detailed basin analysis. Petroleum-system analyses are not generally performed at scales applicable to issues of resource conservation and industry regulation. Instead, each petroleum system can be subdivided into geological plays.

A geological play can be defined as a set of known or postulated oil or gas accumulations (pools and deposits)[6] within a petroleum system sharing similar geological, geographic, and temporal properties, such as source rock, migration pathways, timing, trapping mechanism, and hydrocarbon type. The geographic limit of each play represents the limits of the geological elements that define the play. An example of a geological play in Alberta would be the Pembina Nisku Formation pinnacle-reef sour-gas play.

5 Crude bitumen is extra heavy oil that in its natural state will not flow to a well. Most bitumen in Alberta has been formed by the biodegradation of lighter crude oils.

6 In general, pools are discrete accumulations of hydrocarbons, whereas deposits are widespread continuous accumulations of hydrocarbons and coal. Pools also can be commingled into larger administrative units.

It is common practice for industry to categorize exploration and development opportunities in terms of geological plays. The AER does not currently designate or otherwise formally declare geological plays. The AER does designate oil sands areas, coal fields, oil and gas pools and fields, and strike areas. These constructs were originally congruous with geological plays, but some have devolved into administrative entities as more geological plays became recognized within and across their boundaries.

During 2014, the AER updated its internal play assignments of all existing oil and gas production as reported to Petrinex[7] and mapped to legally recognized pools in the AER's Board Order System. The original play assignments were made in past decades in support of creating oil and gas ultimate potential estimates discussed below. This updated framework will be used to generate transparent and documented play-by-play estimates of resources and reserves by the AER in forthcoming years. This work has already been used to define the boundaries of the AER's Subsurface Orders No. 1 and No. 3, created in early 2015.

2.2 Alberta's Endowment of Energy Resources

Alberta has access to a treasure trove of energy resources: coal, bitumen, and conventional and unconventional oil and gas.

2.2.1 Coal, Bitumen, and Conventional Oil and Gas

Coal seams underlie nearly half of Alberta and have been commercially developed for nearly 150 years by several thousand small, and several dozen large, surface and underground mines. More recently, natural gas from some of those coal seams, known as coalbed methane or CBM, has begun to be recovered, and the full extent of development potential is still unknown. Other ways of exploiting Alberta's vast coal resources (the largest in Canada), such as through in situ gasification or remote mining, hold out the potential for additional future development.

The AER has conducted numerous assessments of the extent of Alberta's oil sands. Consequently, the AER is confident that there are about two trillion barrels of in-place crude bitumen. As one of the largest known petroleum accumulations in the world, Alberta's oil sands rank with those in the Middle East, Venezuela, Russia, and the United States. While only a relatively small portion (less than ten per cent) is known to be recoverable with current technology and anticipated economics, it is enough to assure a source of production for many decades into the future. Additionally, should other portions of the oil sands prove commercial, as seems reasonable given the history of worldwide resource extraction, bitumen production could occur for a long period of time.

Conventional oil and gas have been produced for more than 100 years and, in May 2014, Turner Valley, site of western Canada's first major oil and gas field, held its centennial celebration of the discovery of oil and gas from

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7 Petrinex is a secure, centralized information network facilitating the exchange of petroleum-related information. It allows producers in Alberta to report, manage, and exchange up-to-date volumetric, royalty, and commercial information with government and members of industry, accurately and efficiently.

Dingman No. 1. The discovery of hydrocarbons at Turner Valley led to the first natural gas plant in Alberta. This discovery, and the discovery of oil at Leduc in 1947, has added substantial wealth to the province. The WCSB is predominately a gas-prone basin with commercial quantities of natural gas having been found almost throughout the entire province. Oil pools are also widely distributed throughout the province but tend to be in several large clusters. Alberta produces almost three-quarters of Canada's natural gas and almost half of Canada's oil.

As the conventional production of oil and gas continues to decline, unconventional recovery methods and the exploitation of unconventional reservoirs are on the rise. Reserves and production of crude oil have increased in the last several years, breaking a trend of decades of decline. Natural gas reserves and production continue to generally decline, but an increasingly higher percentage comes from unconventional sources.

2.2.2 Shale Hydrocarbons

In 2012, the ERCB (the immediate predecessor of the AER) released the report *ERCB/AGS Open File Report 2012-06: Summary of Alberta's Shale- and Siltstone-Hosted Hydrocarbon Resource Potential*. The report provides baseline data, information, and an understanding of the geology, distribution, reservoir characteristics, and hydrocarbon resource potential of key shale units in Alberta.[8]

The study concluded that shale hydrocarbon in-place resources are very large and present an important potential energy supply for Alberta and the world. The results demonstrate the size and distribution of shale gas resources in Alberta and may be used to assist in planning resource development and environmental stewardship.

Table 2.1 summarizes the study's estimates of Alberta's shale- and siltstone-hosted hydrocarbon resource endowment for the six investigated units for which available data allowed at least a preliminary determination in billion cubic metres (10^9 m^3). Geological and reservoir engineering constraints, recovery factors, and additional economic factors, as well as social and environmental considerations, will ultimately determine the potential recovery of these large resources. See **Section 2.3.3** for additional discussion on the potential recovery of shale hydrocarbons from the Montney Formation.

Maps of the distribution of the P_{50} estimate of hydrocarbon resources in each formation are in **Appendix F**. Alberta's shale gas resources are discussed further in **Section 5.1.5**.

2.3 Resource Appraisal Methodologies

The AER uses the term "resource appraisal" to encompass all aspects of quantifying Alberta's in-place resources and recoverable reserves. Resource estimation refers to activities that quantify the amount of energy resources in the ground. Reserves determination means those activities that quantify the recoverable portion of these in-place resources (i.e., the established reserves).

[8] Strictly speaking, the portion of the Montney Formation that contains low permeability strata (which formed a key part of the study) is not a "shale" target. While this formation does contain some higher permeability conventional reservoirs, in Alberta it is dominated by siltstone and was included in the study because it is a target for unconventional resource development.

Table 2.1 Summary of estimates of Alberta shale- and siltstone-hosted hydrocarbon resource endowment[a]

Formation	Average adsorbed gas content (%)	Natural gas (10^9 m^3)	Natural gas liquids (10^6 m^3)	Crude oil (10^6 m^3)
Duvernay	6.8 (5.6–8.5)	12 479 (9 934–15 219)	1 798 (1 190–2 589)	9 803 (7 004–13 172)
Muskwa	6.9 (4.1–10.5)	11 812 (8 132–14 839)	2 350 (949–4 181)	18 296 (11 884–25 412)
Montney	17.7 (10.8–26.0)	60 095 (45 917–79 684)	4 583 (1 852–8 631)	21 653 (12 496–35 035)
Banff/Exshaw[b]	5.7 (3.2–10.0)	993 (446–1 975)	15 (5–35)	3 946 (1 426–7 143)
Nordegg[b]	18.2 (4.6–34.8)	4 164 (1 968–7 905)	228 (77–555)	6 011 (3 161–10 550)
Wilrich[b]	33.7 (6.2–59.2)	6 918 (3 237–16 007)	327 (109–707)	7 611 (3 206–27 380)
Total		**96 461 (3 424 Tcf)[c]**	**9 301 (58.6 10^9 bbl)[d]**	**67 320 (423.6 10^9 bbl)[d]**

[a] The medium estimate (P_{50}) with low (P_{90}) to high (P_{10}) estimates in brackets is shown. Data and interpretations were subjected to geostatistical analysis to provide a probabilistic resource evaluation, indicating P_{10}, P_{50}, and P_{90} confidence results of the initial hydrocarbon in-place.

[b] Estimates based on preliminary data.

[c] Trillion cubic feet.

[d] Barrels.

2.3.1 Resource Estimation

The AER generates its own resource estimates. The in-place resource estimation process starts with the AER receiving raw data from energy resource companies, either as specified by legislation or through regulatory applications or submissions, the vast majority of which is well or borehole data. AER geological staff use pertinent data such as geophysical well logs, cores and drill cuttings, core analyses, and well tests (e.g., pressure), together with industry or academic information (e.g., reports, seismic data, or regional studies), to estimate petrophysical information and various geological surfaces and zones. These geological and petrophysical evaluations are used for both regulatory and resource appraisal purposes. Several techniques, including geostatistics, are used in generating a volumetric estimate of in-place resources for the various energy resources.

2.3.2 Reserves Determination

The AER determines two types of estimates of the recoverable portion of Alberta's in-place resources. The portion determined recoverable from known accumulations or deposits using today's technology is classified as "established reserves." The portion determined from known and unknown resources using reasonably foreseeable technology is classified as the "ultimate potential." Established reserves are determined on an ongoing basis, whereas ultimate potentials usually result from major studies conducted periodically. Both terms are estimates of commercial production and are defined in **Section 2.4.**

In determining the established reserves of an energy resource, the AER considers geology, pressures, production, technology, and present and anticipated economics. When estimating in-place quantities, geological factors are the main consideration. However, additional considerations are usually required to reduce the in-place quantity to a more likely developable quantity and to assure the existence and extent of the recoverable portion.

Alberta's production of oil and gas has predominantly come from conventional pools in which hydrocarbons have accumulated in concentrated quantities in porous and permeable reservoirs drainable by vertical wells. The AER determines reserves of conventional pools through the accepted practices of geology-based volumetric estimation, production decline analysis, and material balance methodology.

Initially there is a higher level of uncertainty in the reserves estimates, but this level decreases over the life of a pool as more information becomes available and actual production is observed and analyzed. Analysis of production decline data is a primary method of determining recoverable reserves. It also gives a realistic estimation of a pool's recovery efficiency when it is combined with a volumetric or a material balance estimate of the in-place resource.

The determination of reserves in deposits is similar to the methods used to determine pool reserves. One or more factors are applied against an in-place volume or tonnage to determine the recoverable portion of the resource. These reserves are often estimated by three-dimensional geological models that routinely involve the data from hundreds or thousands of wells and drillholes.

2.3.3 Ultimate Potential

Ultimate potential estimates represent recoverable quantities. They are determined for each energy resource commodity over the entire province and are based on a future end-of-the-day timescale. These estimates consider all of an energy resource's development up to the time of the estimate and anticipate when exploration activity may end and the type of technology that might reasonably be expected to be used in the future. Potential future economic circumstances are also considered. These estimates form a reasonable and credible basis for longer term production forecasts and government policy decisions on energy resources. Over time, more and more of the ultimate potential quantities are expected to be transitioned into reserve numbers.

In 2013, the National Energy Board, in conjunction with the B.C. Oil and Gas Commission, the AER, and the B.C. Ministry of Natural Gas Development, released the report *Energy Briefing Note – The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta*. **Table 2.2** shows the Alberta portion of both the in-place resource estimates and the recoverable ultimate potential estimates for natural gas, natural gas liquids, and crude oil for the Montney Formation. This formation has the largest volumes of hydrocarbons of the six stratigraphic units listed in **Table 2.1**. The slightly higher in-place values shown in **Table 2.2**, when compared to **Table 2.1**, are due to the inclusion, in Alberta, of the lowermost Doig siltstone (making the stratigraphic unit equivalent to the Upper Montney Formation in British Columbia).

Should the estimated ultimate potential of marketable natural gas shown in **Table 2.2** actually be recovered, it would mark a five-fold increase in Alberta's remaining gas reserves. The potential recoverable natural gas liquids

Table 2.2 Ultimate potential of the Montney Formation, including the lowermost Doig siltstone, unconventional hydrocarbons in Alberta

	Ultimate in-place			Ultimate potential		
Hydrocarbon type	Low	Expected	High	Low	Expected	High
Natural gas (10^9 m^3)	48 124 (1 699)[a]	65 415 (2 309)[a]	83 474 (2 947)[a]	3 286 (116)[a]	5 042 (178)[a]	7 946 (281)[a]
NGLs (10^6 m^3)	1 910 (12 020)[b]	4 863 (30 599)[b]	8 924 (56 150)[b]	122 (769)[b]	298 (1 874)[b]	584 (3 674)[b]
Oil (10^6 m^3)	12 654 (79 621)[b]	22 045 (138 706)[b]	35 373 (222 569)[b]	71 (444)[b]	174 (1 096)[b]	375 (2 360)[b]

[a] Imperial equivalent in trillion cubic feet.

[b] Imperial equivalent in million barrels.

and crude oil would represent a 118 per cent and a 65 per cent increase respectively in Alberta's remaining reserves.

2.4 Resources and Reserves Classification System

The AER reports the reserves of Alberta by commodity (crude bitumen, crude oil, natural gas, natural gas liquids, sulphur,[9] and coal) based on the Inter-Provincial Advisory Committee on Energy (IPACE) system for uniform terminology and definitions in estimating and publishing hydrocarbon reserves information in Canada. The IPACE system was adopted by most government and national bodies for reserves reporting in Canada in 1978 and has been in use since that time. The IPACE system was designed as a simple categorization of reserves to facilitate understanding and transparency in reporting to the public. The key definitions in the IPACE system are as follows:

- Initial volume in-place – the gross volume of crude oil, crude bitumen, or raw natural gas calculated or interpreted to exist in a reservoir before any volume has been produced.
- Established reserves – those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing, or production, plus that judgement portion of contiguous recoverable reserves that are interpreted to exist, from geological, geophysical or similar information, with reasonable certainty.
- Initial established reserves – established reserves prior to the deduction of any production.
- Remaining established reserves – initial established reserves less cumulative production.
- Ultimate potential – an estimate of the initial established reserves that will have become developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects

9 Sulphur reserves are included because they are a direct by-product of sour natural gas development, as well as that portion of raw crude bitumen that is upgraded.

of that area and anticipated technology and economic conditions. Ultimate potential includes cumulative production, remaining established reserves, and future additions through extensions and revisions to existing pools and the discovery of new pools.

The IPACE system was designed, and is most appropriate, for use with conventional oil and gas resources. Consequently, the AER has introduced changes to the IPACE system to make it compatible for all energy resources, including coal. More recently, alterations have also been applied to unconventional resources, such as crude bitumen, to more completely report the resource endowment of Alberta.

Since 1978, and particularly since 1997, the mineral and petroleum industries have strived for tighter definitions of reserves to better suit financial markets. In Canada, these efforts include the promulgation of *National Instrument (NI) 43-101*: *Standards of Disclosure for Mineral Projects*[10] in 2000 for Canadian minerals (including coal) securities reporting, the promulgation of *NI 51-101: Standards of Disclosure for Oil and Gas Activities* in 2003 for petroleum reserve reporting to Canadian securities regulators, and the creation of and updates to the *Canadian Oil and Gas Evaluation Handbook (COGEH)*.[11] International standards include the *International Template for Reporting of Exploration Results, Mineral Resources and Mineral Reserves* in 2003, the *Petroleum Resources Management System (PRMS)*[12] in 2007, and the *United Nations Framework Classification for Fossil Energy and Mineral Reserves and Resources 2009 (UNFC-2009)*.[13] The AER continues to review these efforts and will decide to either maintain or modify the IPACE system or to adopt one or more of these newer frameworks in the future.

[10] The technical basis of *NI 43-101* is the *Definition Standards on Mineral Resources and Mineral Reserves* prepared by the Canadian Institute of Mining, Metallurgy and Petroleum. This standard is based on other international standards that have now been consolidated into the template, which was prepared by the Committee for Mineral Reserves International Reporting Standards.

[11] The COGEH, first published in 2002, was prepared by the Calgary Chapter of the Society of Petroleum Evaluation Engineers and the then Petroleum Society of the Canadian Institute of Mining, Metallurgy and Petroleum (now part of the Society of Petroleum Engineers). COGEH forms the technical basis of *NI 51-101*.

[12] The PRMS was prepared by the Society of Petroleum Engineers and reviewed and jointly sponsored by the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers.

[13] The first edition of *UNFC-2009* was published in 2004.

HIGHLIGHTS

Information on geological plays in Alberta and future work for crude bitumen reserves.

In 2014, total raw bitumen production increased by about 11 per cent, mineable production increased by 6 per cent, and in situ production increased by 14 per cent. Upgraded bitumen production increased by 2 per cent.

The AER expects in situ crude bitumen production to increase to 383.6 10^3 m^3/d by 2024.

3 CRUDE BITUMEN

Crude bitumen is extra-heavy oil that in its natural state does not flow to a well. It occurs in sand (clastic) and carbonate formations in northern Alberta. Crude bitumen and the rock material it is found in, together with any other associated mineral substances other than natural gas, are called oil sands. For administrative purposes, the geological formations and the geographic areas containing the bitumen are designated as oil sands areas (OSAs). Other heavy oil is deemed to be oil sands if it is located within an OSA. Since some bitumen within an OSA will flow to a well, it is amenable to primary development and is considered to be primary crude bitumen in this report.

The three designated OSAs in Alberta are shown in **Figure R3.1**. Combined, they occupy an area of about 142 000 square kilometres (km^2) (54 000 square miles). Within these OSAs are 15 oil sands deposits, which have been designated according to the specific geological zones containing the oil sands. The known extent of the two largest deposits, the Athabasca Wabiskaw-McMurray and the Athabasca Grosmont, as well as the smaller Cold Lake Clearwater and Peace River Bluesky-Gething deposits, are also shown in the figure. As an indication of scale, the right-hand edge shows township markers that are about 50 km (30 miles) apart.

Depending on the depth of the deposit, one of two methods is used to recover bitumen. North of Fort McMurray, crude bitumen occurs near the surface and can be recovered economically by open-pit mining. In this method, overburden is removed, oil sands ore is mined, and bitumen is extracted from the mined material in large facilities using hot water. At greater depths, where it is not economical to recover the bitumen by mining, in situ methods are employed. In situ recovery takes place both by primary development, similar to conventional crude oil production, and by enhanced development. Cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD) are the two main methods of enhanced development whereby the reservoir is heated to reduce the viscosity of the bitumen, allowing it to flow to a vertical or horizontal wellbore.

3.1 Reserves of Crude Bitumen

3.1.1 Provincial Summary

The AER continually updates Alberta's crude bitumen resources and reserves on both a project and deposit basis. The remaining established reserves as of December 31, 2014, are 26.43 billion cubic metres (10^9 m^3). This is a slight reduction from the previous year due to 0.13 10^9 m^3 of production. Of the total

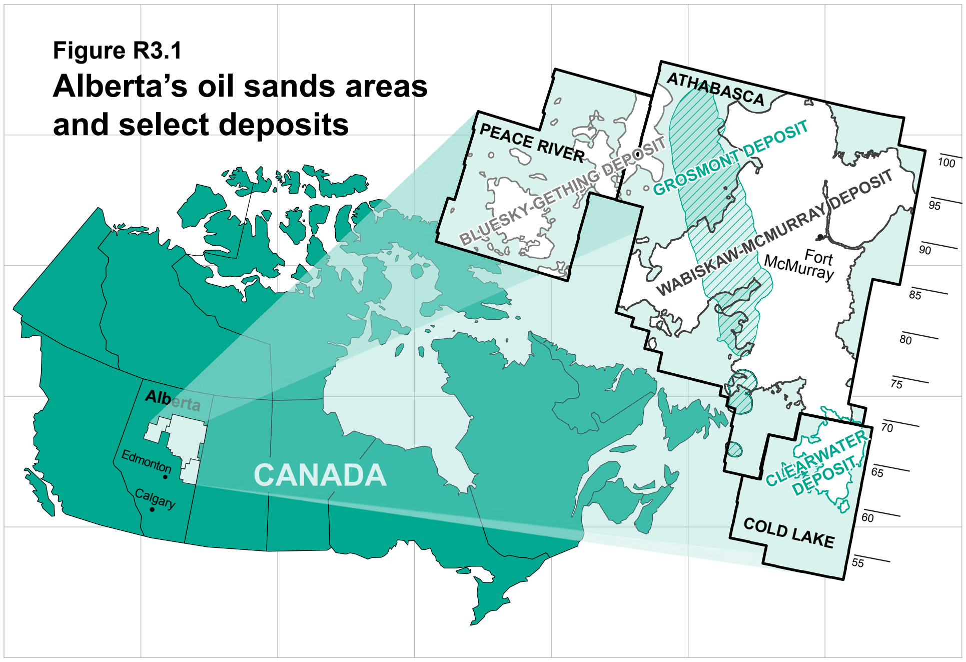


Figure R3.1
Alberta's oil sands areas and select deposits

26.43 10^9 m^3 remaining established reserves, 21.27 10^9 m^3, or about 80 per cent, is considered recoverable by in situ methods, while the remaining 5.16 10^9 m^3 is recoverable by surface mining methods. Of the in situ and mineable totals, the remaining established reserves within active development areas is 3.88 10^9 m^3. **Table R3.1** summarizes the in-place and established mineable and in situ crude bitumen reserves.

The changes, in million cubic metres (10^6 m^3), in initial and remaining established crude bitumen reserves and cumulative and annual production for 2014 are shown in **Table R3.2**. Crude bitumen production in 2014 totalled 134 10^6 m^3, with in situ operations contributing 73 10^6 m^3.

The remaining established reserves in active development areas are presented in **Figure R3.2**. The staircase configuration is due to the start-up of new large mining projects. The slow decline between each new start-up is due to annual production.

3.1.2 Initial In-Place Volumes of Crude Bitumen

The crude bitumen resource volumes and basic reservoir data are presented on a deposit basis in **Appendix B** (**Table B.1** and **Table B.2**) and are summarized by formation in **Table R3.3**. Efforts to update the province's crude bitumen resources and reserves began in 2003. Since then, 11 of the 15 debbposits have been updated (**Table R3.3**). The Athabasca Wabiskaw-McMurray deposit, with the largest cumulative and annual production, was updated for year-end 2004. It was then revised again in 2009 to take new drilling into account. The Cold Lake Clearwater deposit has the second largest production and was updated for year-end 2005. The northern portion of the Cold Lake Wabiskaw-McMurray deposit was also updated for year-end 2005. The Peace River Bluesky-Gething deposit was updated for year-end 2006.

Table R3.1 In-place volumes and established reserves of crude bitumen (10^9 m^3)

Recovery method	Initial volume in-place	Initial established reserves	Cumulative production	Remaining established reserves	Remaining established reserves under active development
Mineable	20.8	6.16	0.99	5.16	3.57
In situ	272.3	21.94	0.67	21.27	0.31
Total	**293.1** (1 845 10^9 bbl)[b]	**28.09**[a] (176.8 10^9 bbl)[b]	**1.66** (10.4 10^9 bbl)[b]	**26.43**[a] (166.3 10^9 bbl)[b]	**3.88** (24.4 bbl)[b]

[a] Any discrepancies are due to rounding.

[b] bbl = barrels.

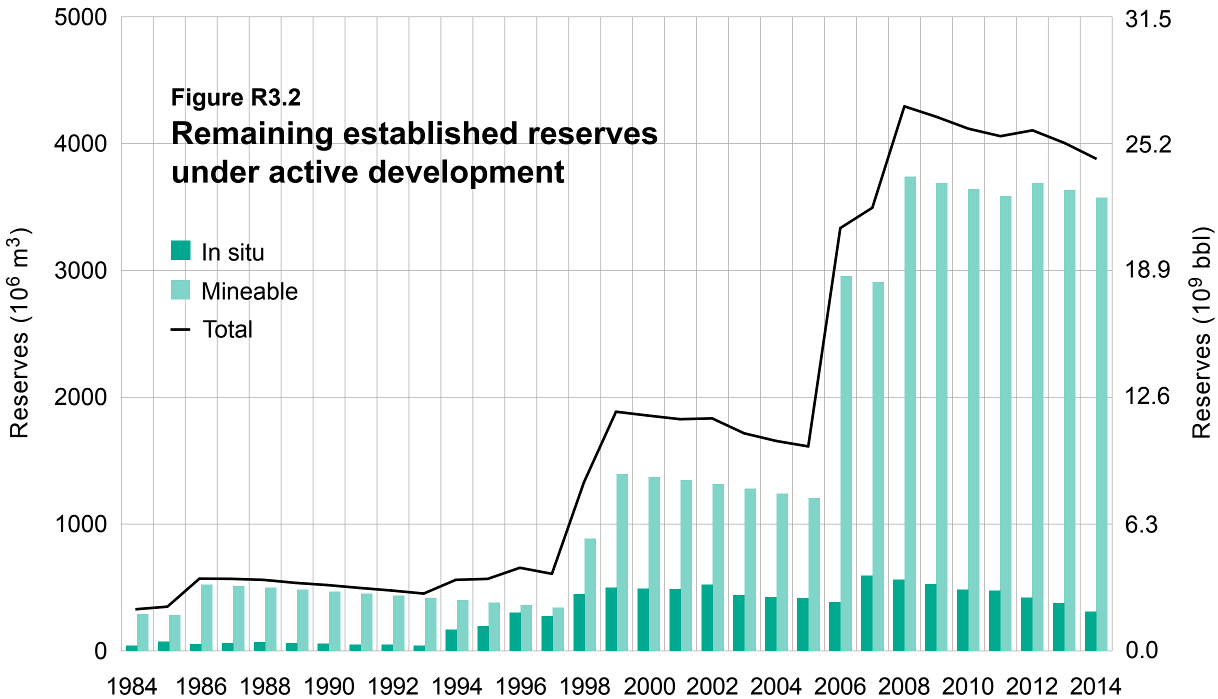
Table R3.2 Reserve and production change highlights (10^6 m^3)

	2014	2013	Change[a]
Initial established reserves			
Mineable	6 157	6 157	0
In situ	21 935	21 935	0
Total[a]	**28 092**	**28 092**	**0**
	(176 780 10^6 bbl)[b]	(176 780 10^6 bbl)[b]	
Cumulative production			
Mineable	991	930	+60[c]
In situ	670	597	+73[c]
Total[a]	**1 661**	**1 527**	**+134**[c]
Remaining established reserves			
Mineable	5 166	5 226	−60
In situ	21 265	21 339	−73
Total[a]	**26 431**	**26 565**	**−1 334**
	(166 325 10^6 bbl)[b]	(167 171 10^6 bbl)[b]	
Annual production			
Mineable	60	57	+3
In situ	73	64	+9
Total[a]	**134**	**121**	**+13**

[a] Any discrepancies are due to rounding.

[b] bbl = barrels.

[c] Change in cumulative production is a combination of annual production and all adjustments to previous production records.



In 2009, the AER completed a major review of the Cold Lake Upper and Lower Grand Rapids deposits and the Athabasca Grosmont deposit. The Athabasca Upper, Middle, and Lower Grand Rapids deposits and the Athabasca Nisku deposit were reassessed for year-end 2011. Bitumen pay thickness maps for these deposits are in **Appendix E**. Also included in **Appendix E** are two structure contour maps of the sub-Cretaceous unconformity. One is a regional map covering all the OSAs, the other is a map detailing the Cold Lake OSA.

Recently, industry has been actively exploring the Leduc Formation for potential bitumen resources west of Fort McMurray. Preliminary results indicate that bitumen pay thickness may exceed 100 m.

The quality of an oil sands deposit depends primarily on the degree of saturation of bitumen within the reservoir and the thickness of the saturated interval. Bitumen saturation decreases as the shale or clay content within the reservoir increases or as the porosity decreases. The relative amount of bitumen is expressed as mass per cent in clastics (the percentage of bitumen relative to the total mass of the oil sands, which includes sand, shale or clay, bitumen, and water). In carbonates, the relative amount of bitumen is expressed as bitumen saturation (the percentage of the volume of pore space that contains bitumen). The selection of appropriate saturation and thickness cutoffs for determining resources and reserves varies depending on the purpose of the resource evaluation and other factors, such as changes in technology and economic conditions.

Initial in-place volumes of crude bitumen in each deposit were determined using geophysical logs, core, and core analyses. Initially, crude bitumen within the Cretaceous sands was evaluated using a minimum saturation cutoff of 3 mass per cent crude bitumen and a minimum saturated zone thickness of 1.5 m for in situ areas. As of year-end 1999, the saturation cutoff was increased to 6 mass per cent for areas amenable to surface mining. The Athabasca Wabiskaw-McMurray; Athabasca Upper, Middle, and Lower Grand Rapids; Cold Lake Clearwater;

Cold Lake Upper and Lower Grand Rapids; and the Peace River Bluesky-Gething deposits, as well as a portion of the Cold Lake Wabiskaw-McMurray deposit, were estimated using a 6 mass per cent saturation cutoff.

The crude bitumen within the carbonate deposits was originally determined using a minimum bitumen saturation of 30 per cent of pore volume and a minimum porosity value of 5 per cent. In the revision of the Athabasca Grosmont and Nisku deposits, a pore volume of 50 per cent and a porosity of 8 per cent were chosen as more appropriate cutoff values.

The AER believes that in measuring the quality of an oil sands area, cutoffs of 6 mass per cent for clastic bitumen deposits and a pore volume of 50 per cent and a porosity of 8 per cent for carbonate bitumen deposits more accurately reflect the volumes from which bitumen can reasonably be expected to be recovered.

Table R3.3 Initial in-place volumes of crude bitumen as of December 31, 2014

Oil sands area / Oil sands deposit	Initial volume in-place (10^6 m^3)	Area (10^3 ha)[a]	Average pay thickness (m)	Average reservoir parameters: Mass (%)	Pore volume oil (%)	Average porosity (%)
Athabasca						
Upper Grand Rapids	5 817	359	8.5	9.2	58	33
Middle Grand Rapids	2 171	183	6.8	8.4	55	32
Lower Grand Rapids	1 286	134	5.6	8.3	52	33
Wabiskaw-McMurray (mineable)	20 823	375	25.9	10.1	76	28
Wabiskaw-McMurray (in situ)	131 609	4 694	13.1	10.2	73	29
Nisku	16 232	819	14.4	5.7	68	20
Grosmont	64 537	1 766	23.8	6.6	79	20
Subtotal	**242 475**					
Cold Lake						
Upper Grand Rapids	5 377	612	4.8	9.0	65	28
Lower Grand Rapids	10 004	658	7.8	9.2	65	30
Clearwater	9 422	433	11.8	8.9	59	31
Wabiskaw-McMurray	4 287	485	5.1	8.1	62	28
Subtotal	**29 090**					
Peace River						
Bluesky-Gething	10 968	1 016	6.1	8.1	68	26
Belloy	282	26	8.0	7.8	64	27
Debolt	7 800	258	25.3	5.1	66	18
Shunda	2 510	143	14.0	5.3	52	23
Subtotal	**21 560**					
Total	**293 125**					

[a] ha = hectare.

Within the Athabasca OSA is the AER-defined surface mineable area (SMA). It encompasses an area of 51½ townships north of Fort McMurray, covering the part of the Athabasca Wabiskaw-McMurray deposit where the total overburden thickness generally does not exceed 65 m. Given the thinner overburden, it is presumed that the main recovery method will be surface mining. Outside of the SMA, in the designated OSAs, in situ technology is the only viable recovery mechanism to date.

The defined boundaries of the SMA are simply for resource administration purposes and carry no regulatory authority. While the AER has estimated mineable reserves from unmined areas within the SMA for provincial resource assessment, surface mining may not actually take place, possibly reducing the estimate of mineable reserves. Within the SMA, just under 50 per cent of the initial mineable bitumen in-place resources occurs at a depth of less than 25 m of overburden. Since the boundaries of the SMA are defined using the boundaries of townships, a few areas of deeper bitumen resources more amenable to in situ recovery are included (i.e., the extent of the SMA covers both mineable and in situ resources). Estimates of mineable bitumen exclude those volumes within the SMA that are beyond mineable depths. Conversely, in situ estimates include all areas outside the SMA, as well as deeper areas within the SMA, which are generally greater than 65 m.

The in-place resource values in **Table R3.3** represent the total crude bitumen accumulated throughout the deposit where the cumulative thickness is equal to or greater than 1.5 m; however, current and anticipated recovery operations often only develop the better quality portion of this total. This developable portion (also known as mineable and exploitable) varies depending on the type of recovery technology employed. Recovery factors are normally applied against this developable portion to determine the established reserves. The parameters used to reduce the total in-place volumes to a developable subset are given in **Section 3.1.3**.

3.1.3 Established Reserves

There are two types of established reserves of crude bitumen: mineable reserves that are expected to be recovered by surface mining operations and in situ reserves that are expected to be recovered through wellbores using in situ recovery methods.

3.1.3.1 Surface-Mineable Crude Bitumen Reserves

With the 2008 expansion of the SMA and the subsequent updating of the Athabasca Wabiskaw-McMurray deposit (the only oil sands deposit in the SMA), the AER now estimates that the SMA contains 20.8 10^9 m^3 of initial bitumen in-place resources at depths most suitable to mining technologies, generally less than 65 m. For year-end 2008, economic criteria were applied to potentially mineable areas in the total in-place portion of the SMA. Economic strip ratio (ESR) criteria, along with a minimum saturation cutoff of 7 mass per cent bitumen and a minimum saturated interval thickness cutoff of 3.0 m, were applied. The ESR criteria are fully explained in Appendix III of *ERCB Report 79-H: Alsands Fort McMurray Project*. This method reduced the total initial mineable bitumen in-place resources of 20.8 10^9 m^3 to 10.3 10^9 m^3 as of December 31, 2008.

Factors were then applied to the initial mineable volume in-place to determine the established reserves. A series of reduction factors were applied to take into account bitumen ore sterilized due to environmental protection corridors along major rivers, small isolated ore bodies, and the location of surface facilities (plant sites, tailings ponds, and waste dumps). Each of these reductions is thought to represent about 10 per cent of the total volume; therefore, each factor is set at 90 per cent. A combined mining and extraction recovery factor of 82 per cent is applied to this reduced resource volume. This recovery factor reflects the combined loss, on average, of 18 per cent of the in-place volume by mining operations and extraction facilities. The resulting initial established reserves of crude bitumen is 6.16 10^9 m^3. As of December 31, 2014, the remaining established mineable crude bitumen reserves has decreased from 5.22 10^9 m^3 at year-end in 2013 to 5.16 10^9 m^3 as a result of production.

The remaining established crude bitumen reserves from deposits under active development as of December 31, 2014, are presented in **Table R3.4**. At the end of 2014, almost three quarters of the initial established reserves were under active development. Currently, Canadian Natural Resources Limited (CNRL Horizon), Shell Canada Energy Limited (Shell Muskeg River and Shell Jackpine), Imperial (Kearl), Suncor Energy Inc. (Suncor), and Syncrude Canada Ltd. (Syncrude) are the only producers in the SMA, with a combined cumulative bitumen production of 991 10^6 m^3. The Fort Hills project (owned by Suncor, Total E&P Canada Ltd. [Total], and Teck Resources Ltd. [Teck]) is not yet producing bitumen but is considered to be under active development and is included in **Table R3.4**. The AER has adjusted the initial mineable volume in-place and the initial established reserves for the Fort Hills mine based on recent drilling information and changes to the project area. Total's Joslyn North mine project was removed from **Table R3.4** as the development was halted. The project reserve estimates are not yet available to include in **Table R3.4**. The only mine project application currently under review is Teck Frontier.

Production from the six current surface mining operations amounted to 60.23 10^6 m^3 in 2014, with 18.00 10^6 m^3 from the Syncrude project, 15.91 10^6 m^3 from the Suncor project, 7.67 10^6 m^3 from the Shell Muskeg River project, 6.50 10^6 m^3 from the Shell Jackpine project, 7.52 10^6 m^3 from the CNRL Horizon project, and 4.64 10^6 m^3 from the Imperial Kearl project.

Table R3.4 Mineable crude bitumen reserves in areas under active development as of December 31, 2014

Development	Project area[a] (ha)	Initial mineable volume in-place (10^6 m^3)	Initial established reserves (10^6 m^3)	Cumulative production (10^6 m^3)	Remaining established reserves (10^6 m^3)
CNRL Horizon	28 482	834	537	34	503
Fort Hills	17 864	556	382	0	382
Imperial Kearl	19 674	1 324	872	6	866
Shell Muskeg River	13 581	672	419	94	325
Shell Jackpine	7 958	361	222	24	198
Suncor	19 155	990	687	347	340
Syncrude	44 037	2 071	1 306	486	820
Total	**150 751**	**6 826**	**4 425**	**991**	**3 435**

[a] The project areas correspond to the areas defined in the project approval.

3.1.3.2 In Situ Crude Bitumen Reserves

The AER has determined in situ initial established reserves for those areas considered suitable for in situ recovery methods (**Table R3.5**). Reserves are estimated using cutoffs appropriate for the type of development and differences in reservoir characteristics. For each oil sands deposit with commercial development, the areas with potential for thermal development were determined using a minimum continuous zone thickness of 10.0 m. For deposits with primary development, a minimum continuous zone thickness of 3.0 m (or lower if currently being recovered at a lesser thickness) was used. While some reserve estimates have been updated using a minimum saturation cutoff of 6 mass per cent bitumen, much of the current data is still based on the 3 mass per cent bitumen cutoff for most deposits. Future reserve estimates will be based on values higher than 3 mass per cent.

Recovery factors of 20 per cent for thermal development and 5 per cent for primary development were applied to areas that met the cutoffs. The deposit-wide recovery factor for thermal development is lower than some of the

Table R3.5 In situ crude bitumen reserves in areas under active development as of December 31, 2014[a]

Development	Initial volume in-place (10^6 m^3)	Recovery factor (%)	Initial established reserves (10^6 m^3)	Cumulative production[b] (10^6 m^3)	Remaining established reserves (10^6 m^3)
Peace River Oil Sands Area					
Thermal commercial projects	63.7	40	25.5	12.1	13.4
Primary recovery schemes	375.0	10	37.5	20.4	17.1
Subtotal[c]	**438.7**		**63.0**	**32.6**	**30.4**
Athabasca Oil Sands Area					
Thermal commercial projects	391.8	50	195.9	190.6	5.3
Primary recovery schemes	1 026.2	5	51.3	26.9	24.4
Enhanced recovery schemes[d]	(365.0)[e]	10	36.5	30.4	6.1
Subtotal[c]	**1 418.0**		**283.7**	**247.9**	**35.8**
Cold Lake Oil Sands Area					
Thermal commercial (CSS)[f]	1 212.8	25	303.2	269.8	33.4
Thermal commercial (SAGD)[g]	33.8	50	16.9	5.8	11.1
Primary recovery schemes	6 257.5	5	312.9	114.1	198.8
Subtotal[c]	**7 504.1**		**633.0**	**389.7**	**243.3**
Total[c]	**9 360.8**		**979.7**	**670.1**	**309.6**

[a] Thermal reserves are reported only for lands on which thermal recovery is approved and drilling development has occurred.

[b] Includes amendments to production reports.

[c] Any discrepancies are due to rounding.

[d] Schemes currently on polymer injection or waterflooding in the Brintnell-Pelican area. Previous primary production is included under primary recovery schemes.

[e] The in-place number is that part of the initial volume available for primary recovery schemes that will see incremental production due to polymer injection or waterflooding.

[f] Cyclic steam stimulation projects.

[g] Steam-assisted gravity drainage projects.

recovery factors for projects under active development to account for the uncertainty in the recovery processes and the uncertainty of development in the poorer quality resource areas.

The volume of the in-place crude bitumen was reassessed in the Athabasca Grosmont deposit in 2009 and the Athabasca Nisku and Upper, Middle, and Lower Grand Rapids deposits in 2011. No reserves were estimated as no commercial projects are currently operating within these deposits. Exploration has occurred and different recovery methods have been experimented with, but commercial operations have yet to be established. The AER estimates reserves only in deposits where commercial operations are in place.

In 2014, the in situ bitumen produced was 73.43 10^6 m^3, an increase from 64.40 10^6 m^3 in 2013. Cumulative production within in situ areas now totals 670.1 10^6 m^3, of which 389.7 10^6 m^3 is from the Cold Lake OSA. The remaining established reserves of crude bitumen from in situ areas decreased from 21.34 10^9 m^3 in 2013 to 21.27 10^9 m^3 in 2014 due to production of 0.07 10^9 m^3.

The AER's 2014 estimate of the established in situ crude bitumen reserves under active development is shown in **Table R3.5.** For 2014, the estimates of crude bitumen for enhanced recovery schemes in the Athabasca OSA have been reassessed; the part of the initial volume available for primary recovery schemes that will see incremental production from polymer injection or waterflooding has increased. The remaining established reserves for Athabasca enhanced recovery schemes have increased from 2.8 10^6 m^3 in 2013 to 6.1 10^6 m^3 in 2014. Information on experimental schemes has been removed from the table due to the limited number of experimental schemes and the confidential nature of the associated production data.

The AER has assigned initial volumes in-place and initial and remaining established reserves for commercial projects and primary recovery schemes where all or a portion of the wells have been drilled and completed. An aggregate reserve is also shown for all commercial projects and primary recovery schemes within a given oil sands deposit and area. Initial established reserves under primary development are based on a 5 per cent average recovery factor. In the Peace River OSA, however, a 10 per cent recovery factor, based on production, is used. The application of various steaming strategies and project designs are reflected in the recovery factors of 40, 50, and 25 per cent for thermal commercial projects in the Peace River, Athabasca, and Cold Lake OSAs, respectively.

The remaining established reserves of crude bitumen within active in situ project areas are estimated to be 309.6 10^6 m^3, a decrease from 375.4 10^6 m^3 in 2013 due to production.

3.1.3.3 Geological Plays of Alberta

A geological play can be defined as a set of known or estimated oil or gas accumulations (pools and deposits[1]) within a petroleum system (a linked assemblage of source rock, migration routes, and ultimate traps) sharing similar geological, geographic, and temporal properties, such as source rock, migration pathways, timing,

[1] When referring to a geological play, a deposit is smaller spatially than the deposits referred to elsewhere in this chapter, which are of a size similar to that of a formation.

trapping mechanism, and hydrocarbon type. The Western Canada Sedimentary Basin contains at least eight petroleum systems (as discussed in **Section 2.1.2**). The oil sands in Athabasca and Cold Lake are mostly within the Exshaw petroleum system whereas Peace River is mixed Gordondale (Nordegg) and Exshaw. Estimates of volumes of hydrocarbon can be quantified for petroleum systems.

Each petroleum system has a number of stratigraphic intervals that can be subdivided into geological plays. The geographic limit of each play represents the limits of the geological elements that define the play. An example of a geological play in Alberta would be the Pembina Nisku Formation pinnacle-reef sour-gas play.

In the future, the AER will use what it understands to be and has defined as a geological play to generate estimates of resources and reserves for geological plays. The AER is currently evaluating a number of geological plays. Numerous factors are considered in determining priority for review, such as industry activity, environmental impact, and safety. At this time the AER is focusing on a number of plays within the Wabiskaw-McMurray stratigraphic interval.

3.1.4 Ultimate Potential of Crude Bitumen

The ultimate potential of crude bitumen recoverable by in situ methods is estimated to be 33 10^9 m^3 from Cretaceous clastic sediments and 6 10^9 m^3 from Paleozoic carbonate sediments. Nearly 11 10^9 m^3 of bitumen was expected to be recovered within the original boundaries of the SMA. The ultimate potential from within the area of expansion has yet to be estimated, leaving the total ultimate potential for crude bitumen unchanged at 50 10^9 m^3.

3.2 Supply of and Demand for Crude Bitumen

This section includes crude bitumen production, upgrading, and disposition of both upgraded and nonupgraded bitumen. Nonupgraded bitumen refers to crude bitumen that is blended with a lighter-viscosity product (referred to as a diluent) to meet specifications for transport through pipelines. Upgraded bitumen refers to the portion of crude bitumen production that is upgraded to synthetic crude oil or other petroleum products. Most upgraded bitumen is used by refineries as feedstock.

To improve the quality of crude bitumen, upgraders chemically alter the bitumen by adding hydrogen, removing carbon, or both.[2] In upgrading, most of the sulphur and other impurities contained in bitumen are removed. The bitumen upgrading process produces off-gas that is high in natural gas liquids (NGLs) and olefins. The off-gas has primarily been used as fuel in oil sands operations; however, there are increasing volumes of off-gas being processed to remove the NGLs and olefins, which are used as feedstock in the petrochemical industry. Most oil sands coke recovered as a by-product of the upgrading process is stockpiled, while small amounts

2 An upgrader is an oil sands processing plant that upgrades bitumen into lighter hydrocarbon products. The AER regulates upgraders as processing plants under the *Oil Sands Conservation Act* and as oil sands processing plants under the *Environmental Protection and Enhancement Act*.

are burned to generate electricity or are sold to market. Sulphur is either stockpiled or shipped to facilities that convert it to sulphuric acid, which is mainly used to manufacture fertilizers.

Condensate and upgraded bitumen are two main types of diluent used to lower the viscosity of bitumen for transport in pipelines, although naphtha, light crude oil, and butanes can also be used to enable the bitumen to meet pipeline specifications.[3] Condensate is lighter than upgraded bitumen as a diluent, which means a smaller volume of condensate is required to move bitumen through a pipeline. On average, a blend of bitumen and condensate will contain about 30 per cent condensate, whereas a blend using upgraded bitumen will contain up to 50 per cent upgraded bitumen to meet pipeline specifications.

If condensate is used as a diluent to transport bitumen to destinations within Alberta, they are usually recycled. However, if they are used to transport bitumen to markets outside Alberta, they are generally not returned to the province. Instead, the condensate is used as part of the feedstock for upgraders and refineries downstream. As demand for condensate has grown, the number of projects aimed at delivering condensate to the province has increased. Details on these projects can be found in **Table S3.2**.

The forecast of crude bitumen and upgraded bitumen production relies heavily on information from project proponents. This includes data on production capacity submitted during a project's application process, in addition to other publicly available materials, such as quarterly reports, presentations, and press releases, which give information on schedules for bringing the resource on stream. A project's viability depends largely on the cost-price relationship between production, capital cost, operating and transportation costs (supply), and the market price for bitumen and upgraded bitumen (demand). Other factors include the refining capacity to handle bitumen or upgraded bitumen and competition with other sources of supply in U.S. and Canadian markets. The forecasts for crude bitumen and upgraded bitumen include production from existing projects, expansions of existing projects, and new projects that have been granted or are currently seeking approval. Demand for upgraded bitumen and nonupgraded bitumen in Alberta is based on refinery demand and transportation needs. Alberta upgraded and nonupgraded bitumen supply in excess of Alberta demand is marketed outside the province.

Project sponsors' projections of existing and future bitumen production can change over time for various reasons with price playing a significant role in their decision-making. In addition, large oil sands production projects are complex and capital intensive. They require long lead and construction times, making the projects vulnerable to material and labour cost increases throughout the planning, construction, and production phases.

3.2.1 Crude Bitumen Production – 2014

Surface mining and in situ production for 2014 are shown graphically by OSA in **Figure S3.1**. In 2014, Alberta produced an average of 366.3 thousand (10^3) m^3/d of crude bitumen from all three OSAs. Compared with 331.4 10^3 m^3/d in 2013, this is an increase of 34.9 10^3 m^3/d, of which 25 10^3 m^3/d is from in situ schemes and

[3] The term condensate, as used in this section, applies to Alberta production of condensate and pentanes plus in addition to imported volumes of condensate.

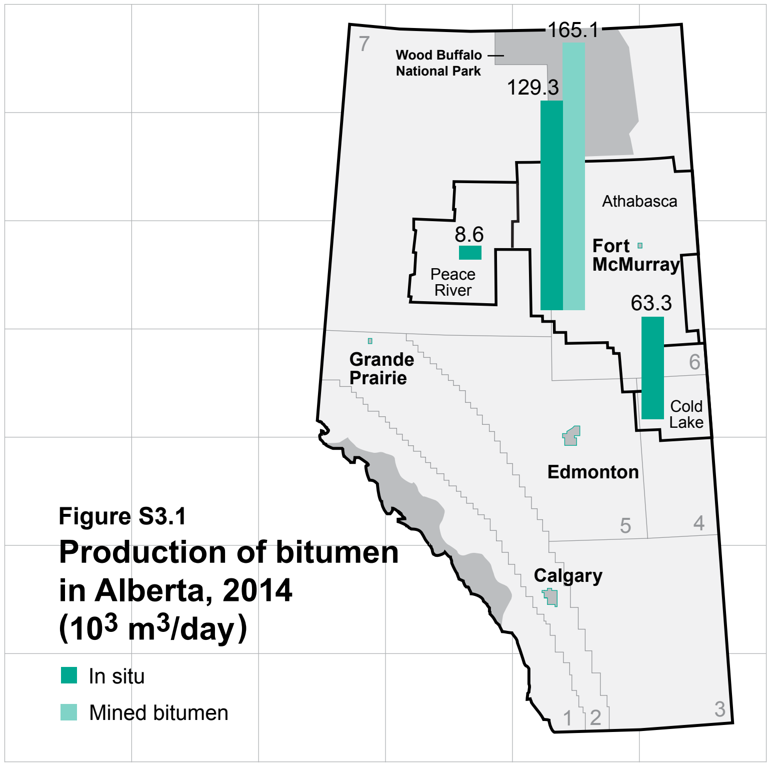


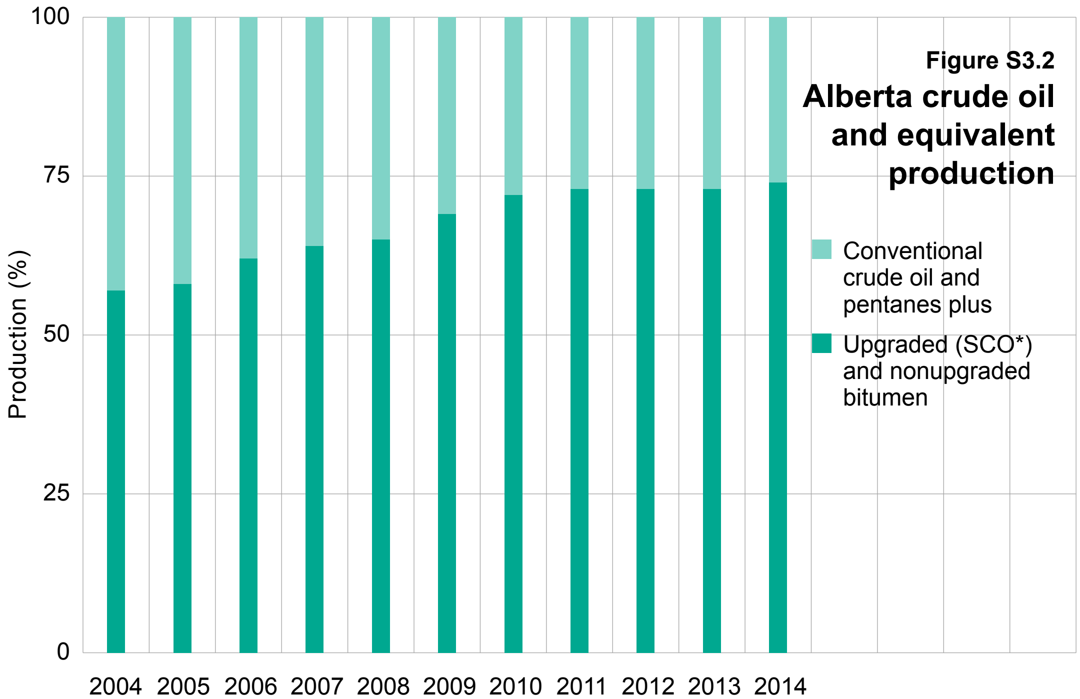
Figure S3.1
Production of bitumen in Alberta, 2014 (10^3 m^3/day)

9.9 10^3 m^3/d is from mining. Regionally, in situ production growth was strongest in Athabasca (24.9 per cent increase) followed by Peace River (1.2 per cent increase). Significant increases in production within Athabasca since 2003 are due to the expansion of steam-assisted gravity drainage (SAGD) development. Cold Lake experienced a decrease (1.4 per cent), mainly due to the shut in of some wells in the area.

Overall, the increase in crude bitumen production of 34.9 10^3 m^3/d represents an annual increase of 10.5 per cent, which is higher than the production increase of 8 per cent between 2012 and 2013. Production from in situ projects continued to exceed mined production in 2014 and is expected to continue to do so going forward. In 2014, in situ production accounted for 55 per cent of total bitumen production, compared with 53 per cent in 2013. **Figure S3.2** shows combined upgraded bitumen and nonupgraded bitumen production as a percentage of Alberta's total crude oil and equivalent production. The combined volume of upgraded bitumen and nonupgraded bitumen has increased from 48 per cent of the province's total crude oil production in 2002 to 74 per cent in 2014. Highlights of annual activity can be found in **Table S3.1**.

3.2.1.1 Mined Crude Bitumen

Annual mined production growth was 9.9 10^3 m^3/d in 2014 as daily volumes grew to an average 165.1 10^3 m^3/d, up from 155.2 10^3 m^3/d in 2013. Production growth in 2014 at 6.4 per cent was slightly higher than growth in 2013 at 5 per cent. The majority of the increase was due to a rate of production of 8.7 10^3 m^3/d from Imperial's Kearl project.



*Synthetic crude oil.

Table S3.1 Crude bitumen production and change highlights (10^3 m^3/d)

	2014	2013	Change	Change (%)[a]
Raw production				
Mineable	165.1	155.2	+9.9	+6.4
In situ	201.2	176.2	+25.0	+14.2
Total	**366.3**	**331.4**	**+34.9**	**+10.5**
Upgraded and nonupgraded production				
Upgraded	151.6	148.8	+2.8	+1.9
Nonupgraded	192.6	160.8	+31.8	+19.8
Total	**344.2**	**309.6**	**+34.6**	**+11.2**

[a] Per cent changes are based on annual production volumes.

The Syncrude (Mildred Lake), Suncor (all mining operations), Shell (Muskeg River and Jackpine), CNRL (Horizon), and Imperial (Kearl) projects accounted for 29.9, 26.4, 23.5, 12.5, and 7.7 per cent of total mined bitumen, respectively.

Syncrude's mined bitumen production in 2014 decreased by 5 per cent relative to 2013 and averaged 49.3 10^3 m^3/d, mainly due to downtime for additional maintenance. Production of mined bitumen at Suncor averaged 43.6 10^3 m^3/d, up 1.7 per cent since 2013. Shell's Muskeg River and Jackpine mining projects combined produced 38.8 10^3 m^3/d in 2014, about 3 per cent increase over 2013. CNRL's Horizon project produced 20.6 10^3 m^3/d in 2014, an increase of 11 per cent since 2013. Imperial's Kearl project started operation earlier than anticipated, which resulted in a significant increase in production of 218 per cent year over year.

3.2.1.2 In Situ Crude Bitumen

In situ crude bitumen production for 2014 increased to an average of 201.2 10^3 m^3/d from 176.2 10^3 m^3/d in 2013, partially due to increases in production at the MEG Christina Lake and the fact that Devon Jackfish Phase 3 project started operation earlier than anticipated. The change in production represents a 14 per cent increase from 2013 to 2014, higher than the annual average growth rate of 12 per cent seen between 2004 and 2013.

Annual total in situ bitumen production, along with the number of bitumen wells on production for each year, is shown in **Figure S3.3**. Currently, there are three main methods for producing in situ bitumen: primary production, cyclic steam stimulation (CSS), and SAGD. The number of producing bitumen wells has increased along with in situ crude bitumen production from 2300 in 1992 to 13 359 in 2014. The average annual productivity of in situ bitumen wells continued to increase, reaching 15.1 m^3/d in 2014, up 6 per cent from 14.2 m^3/d in 2013.

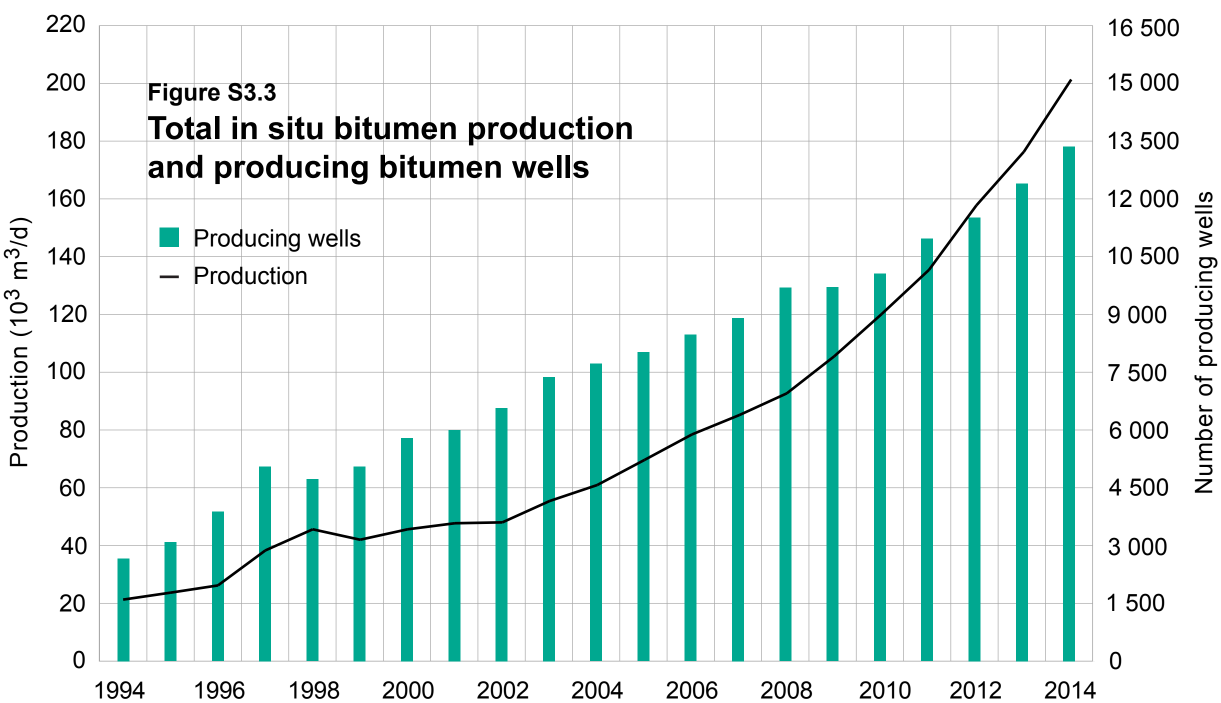


Figure S3.3
Total in situ bitumen production and producing bitumen wells

This change is due to the increase in the number and proportion of SAGD wells, which have higher average productivity rates, compared to CSS wells and primary production wells.

Figure S3.4 shows historical in situ production by OSA. The majority of production continues to come from the Athabasca OSA, accounting for 64 per cent of total production. In 2014, the Athabasca, Cold Lake, and Peace River OSAs produced 129.3 10^3 m^3/d, 63.3 10^3 m^3/d, and 8.6 10^3 m^3/d, respectively.

In situ bitumen production by recovery method per year is shown in **Figure S3.5**. In this report, primary production also includes those schemes that use water and polymer injection (or enhanced recovery) as a recovery method. In 2014, 58 per cent of in situ production was recovered by SAGD, 23 per cent by primary production, and 19 per cent by CSS. SAGD production increased by 26 per cent and was responsible for 97 per cent of the total growth in production between 2013 and 2014. For the second consecutive year, primary production surpassed CSS production, increasing by 5.3 per cent over 2013 levels. CSS declined slightly, falling by 1.5 10^3 m^3/d, or 4 per cent, from 2013 levels.

Figure S3.6 shows the average well productivity in 2014 by recovery method for SAGD, CSS, and primary production. The highest well productivity rates belong to the SAGD method holding the lowest number of wells.

3.2.1.3 Upgraded Bitumen

Currently, the majority of Alberta mined bitumen (about 92.3 per cent) and a small portion of in situ production (about 10.5 per cent) are upgraded. Upgraded bitumen production in 2014 averaged 151.6 10^3 m^3/d, whereas in 2013 it was 148.8 10^3 m^3/d. **Table S3.2** shows upgraded bitumen production in 2014 by individual operator. The ratio of mined bitumen upgraded in Alberta declined by almost 7 per cent compared to 2013 levels. This could be

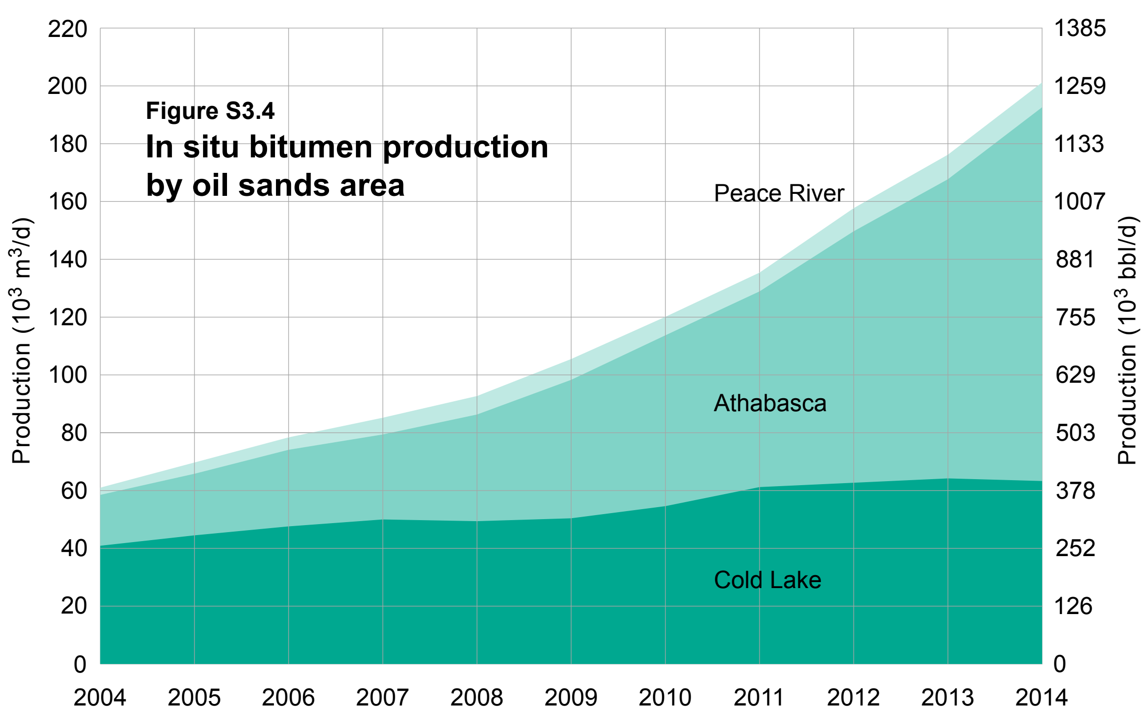


Figure S3.5
In situ bitumen production by recovery method

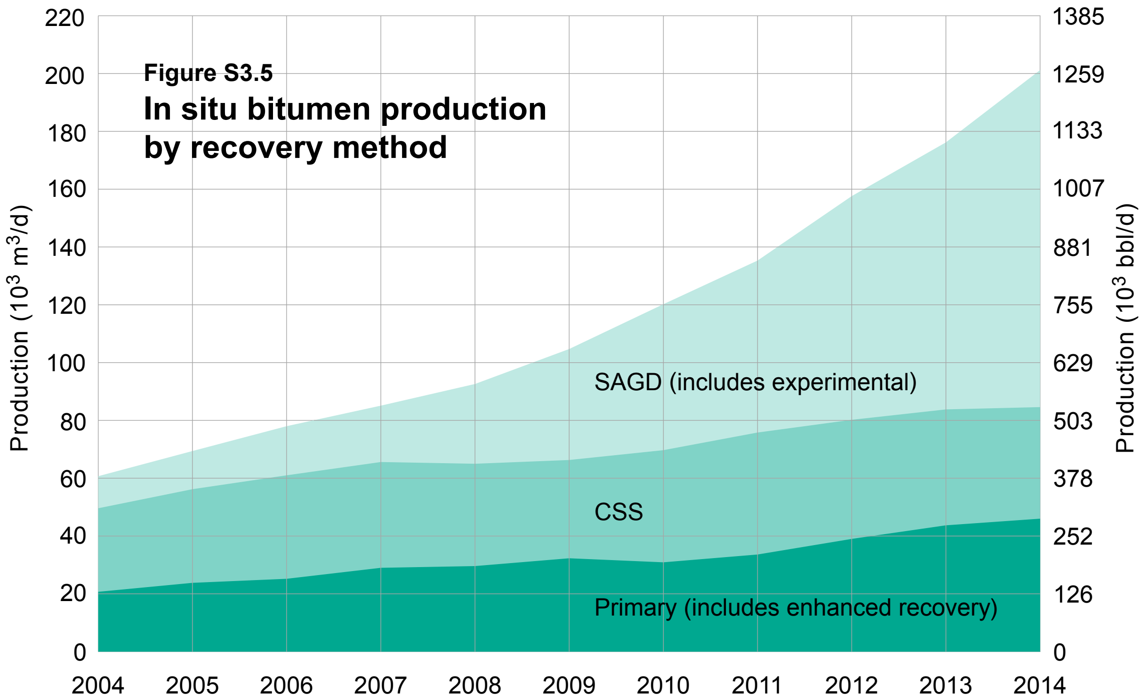


Figure S3.6
In situ bitumen average well productivity by recovery method

[Number of wells]
Productivity m^3/day

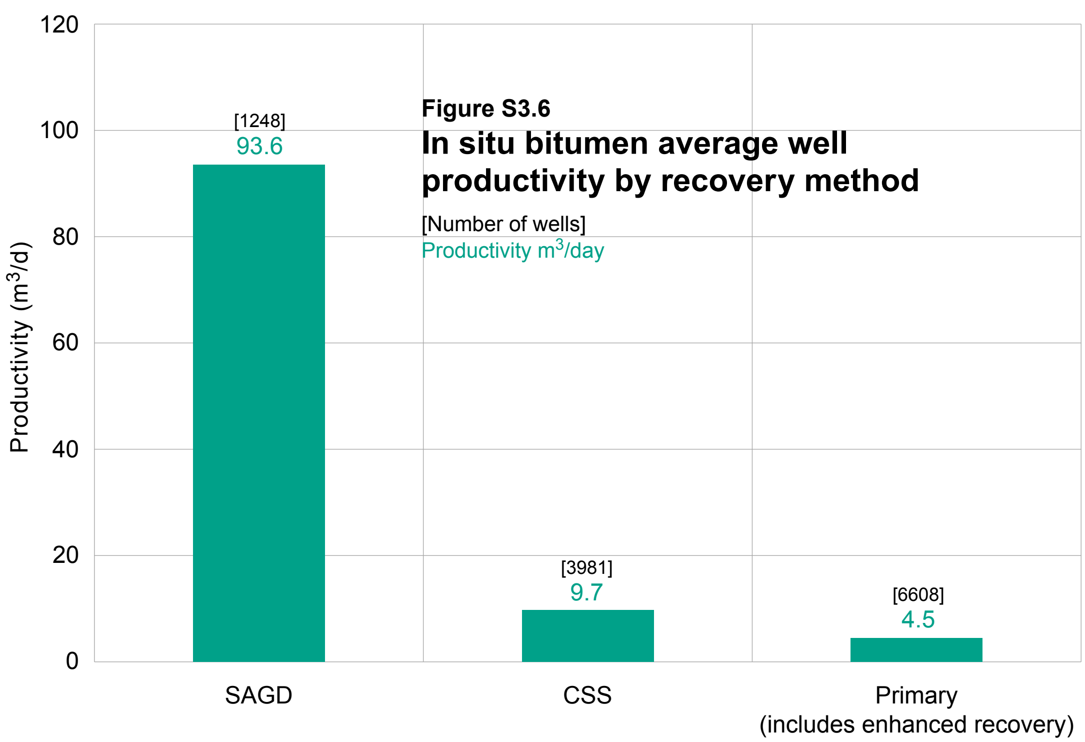


Table S3.2 Average daily upgraded bitumen production in 2014[a]

Company/project name	Production (10^3 m^3/d)
Syncrude	41.5
Suncor	47.0
Shell Canada Scotford	39.2
CNRL Horizon	17.7
Nexen Long Lake	6.1
Total	**151.6**

[a] Any discrepancies are due to rounding.

due to Imperial's Kearl project coming on production earlier than anticipated. Kearl uses a method that greatly enhances its environmental performance and reduces energy needs using a proprietary froth treatment process that eliminates the need to build an upgrader.

Alberta's five upgraders produce a variety of upgraded products: Suncor produces synthetic light sweet and medium sour crudes, including diesel; Syncrude, CNRL Horizon, and Nexen Long Lake produce light sweet synthetic crude; and Shell produces an intermediate refinery feedstock from their Scotford upgrader for their refinery, as well as sweet and heavy synthetic crude oil. Production from new upgraders is expected to align in response to specific refinery product requirements.

Most of the projects use delayed coking as their primary upgrading technology and achieve volumetric liquid yields (upgraded bitumen produced per bitumen processed) of 80 to 90 per cent, whereas projects employing hydrogen addition can achieve volumetric liquid yields of 100 per cent or more. The Nexen Long Lake project uses a carbon rejection upgrading process using conventional thermal cracking, distillation, and solvent deasphalting equipment. The total 2014 production of upgraded bitumen of 56.2 10^6 m^3 was produced from 63.9 10^6 m^3 of raw crude bitumen, an 87.9 per cent overall yield.

3.2.1.4 Gasification

Gasification allows companies to convert materials that would otherwise be low-value products into energy sources and reduces the reliance on external energy sources. Gasification can be used to convert asphaltenes, petroleum coke, and vacuum distillation bottoms into a synthetic gas (syn gas) fuel.

The Nexen Long Lake project integrates the gasification of asphaltenes to produce a syn gas that is used in the SAGD and upgrading operations, significantly reducing the amount of natural gas that is required.

Gasification of low-value products is also being planned for the North West Upgrader currently under construction. The gasifier will produce syn gas and hydrogen from refinery bottoms.

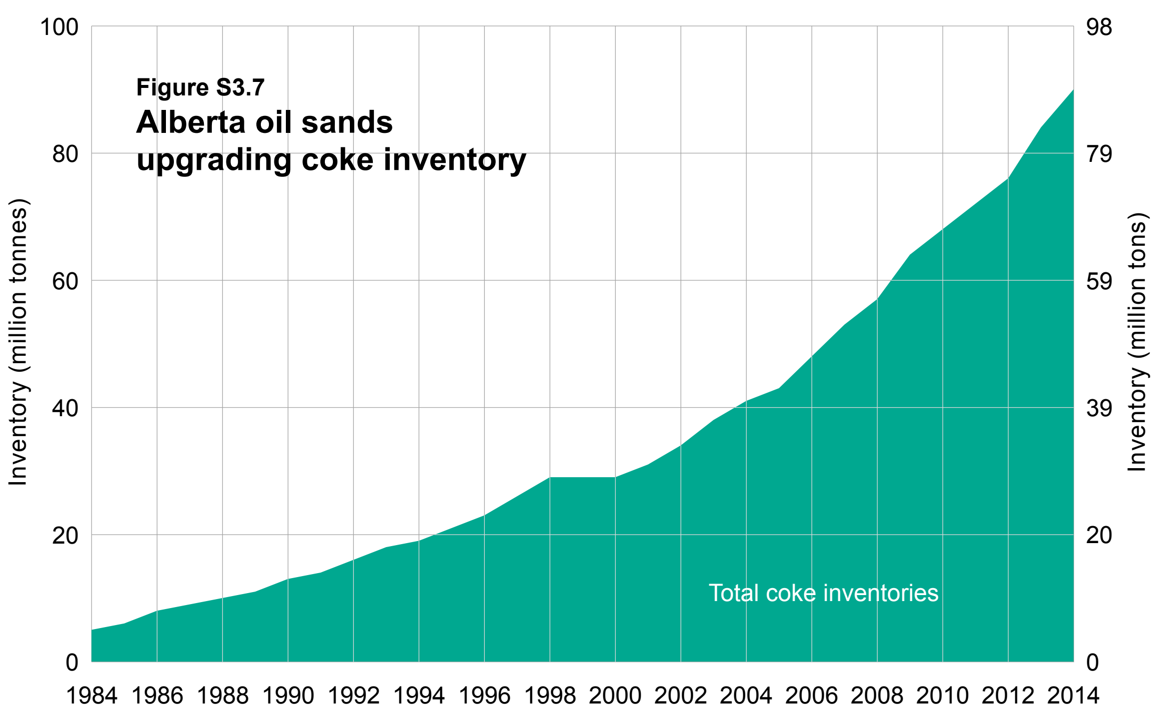
3.2.1.5 Petroleum Coke

Petroleum coke, a by-product of oil sands upgrading, is currently being stockpiled in Alberta because it is considered a potential source of energy. It is high in sulphur but has a lower ash content than conventional crude oil petroleum coke. Suncor, Syncrude, and CNRL Horizon operate oil sands mines near Fort McMurray and have both on-site extraction and upgrading. All three operations produce coke.

Suncor has been burning coke in its boilers for decades at its mine near Fort McMurray, with about 10 per cent of its annual coke production being used for site fuel in 2014. Syncrude began using coke as a site fuel in 1995 and by 2014 used 21 per cent of its annual coke production as site fuel. At CNRL's Horizon project, all coke produced is stockpiled, accounting for about 6 per cent of total coke inventories.

Suncor has been exploring new ways to use its coke surplus, such as using it as a reclamation material to create a solid surface at its Pond 5 project. Suncor's Pond 5 project uses some of the greatest field tailings technology in the world and is projected to be completed in 2019. Although coke capping is not the ultimate solution for closing ponds quicker, it is certainly becoming a viable method to accelerate the process.

Statistics of coke inventories reported in *ST39: Alberta Mineable Oil Sands Plant Statistics* show increases in the total closing inventories per year, as illustrated in **Figure S3.7**. In 2014, coke inventories reached 90 million tonnes, up 6 million tonnes from 2013. This represents an increase of about 7 per cent, which is lower than the 9 per cent rate of growth in 2013. As can be seen in **Figure S3.7**, inventories remained constant from 1998 to 2000 due to higher on-site use of coke by the upgraders; however, this has been followed by a trend of rising inventories that is expected to continue unless other usages or markets are developed.



3.2.2 Supply Costs

The supply cost for a resource project can be defined as the minimum constant dollar price required to recover all capital expenditures, operating costs, royalties, and taxes, as well as to earn a specified return on investment. The supply cost calculation determines a value received per unit of production. For SAGD and standalone mining, this involves solving for a bitumen price at plant gate. For a more meaningful comparison, the results of the supply cost analysis have been converted to a West Texas Intermediate (WTI) price. This price can then be compared with current market prices to assess whether a project or resource is economically attractive. It can also be used for comparative project economics.

3.2.2.1 Assumptions

Although each project is unique in its location and the quality of its reserves, the supply cost analysis relies on more generic project specifications and capital and operating cost estimates.

The generic projects represent proposed project types, including in situ SAGD (with and without cogeneration) and standalone mining with cogeneration. An integrated mine was not considered for this analysis as there are currently no proposed integrated bitumen projects in Alberta. Although significant production currently comes from CSS projects, few new CSS projects have been proposed; therefore, supply costs have not been determined for this recovery method. The wide range in SAGD capital costs represents the current economic environment in which producers are pursuing additional phases, as well as green field development, with the lower range of the capital cost being applicable to phased additions where portions of the infrastructure are already in place.

A major component of operating costs is purchased natural gas for fuel and feedstock. This analysis assumes an average real Alberta reference price of Cdn$3.80 per gigajoule over a project's 30- to 40-year life. For 2014 and beyond, the analysis assumes a nominal discount rate of 10 per cent.

3.2.2.2 Results

The results of the AER's supply cost analysis for crude bitumen projects are shown in **Table S3.3**. Results are provided in both metric and imperial units since North American price data are based on the price of WTI. The input cost data and the resultant supply cost outputs are in 2014 dollars. The capital cost was increased for in situ projects. The range for mining has increased to reflect higher capital costs of projects currently underway due the recent changes in the U.S./Canadian dollar exchange rate.

Given the current and forecast oil prices, **Table S3.3** shows that the near future development of many in situ and mining projects is still supported.

3.2.3 Crude Bitumen Production – Forecast

3.2.3.1 Mined Crude Bitumen

In projecting the future supply of bitumen from mining, the AER considered potential production from existing facilities and supply from future projects. Production from future mining projects considers the high cost of

Table S3.3 Crude bitumen supply costs, 2014

	Production		Capital cost range	Capacity utilization	Estimated supply cost	Purchased natural gas requirement	
Project type	**(10^3 m^3/d)**	**(bbl/d)[a]**	**(millions of dollars)**		**($US WTI equivalent per barrel)**	**(10^3 m^3 gas/ m^3 oil)**	**(Mcf/bbl)[b]**
In situ SAGD	4.8	30 000	900–1 750	90%	50–80	0.177–0.354	1.0–2.0
Standalone mine	15.9	100 000	7 500–9 000	90%	90–105	0.071–0.106	0.4–0.6

[a] bbl/d = barrels per day.

[b] Mcf/bbl = Thousand cubic feet per barrel.

engineering and materials and the substantial amount of skilled labour required to expand existing and new projects. The AER also recognizes that other key factors, such as the forecast of oil prices and the length of the construction period, will affect project timing. Projects that have been approved or have been applied for are considered for the forecast. Announced projects are generally not included in AER forecasts. The projects actually included for the forecast are shown in **Table S3.4**.

Projects awaiting regulatory or corporate approval are generally discounted at 50 per cent, while those under construction or soon to be operating are discounted at rates reflective of past similar schemes projects. Due to uncertainties regarding timing and project scope, some projects, including Syncrude's Aurora expansion project and Teck's Frontier project, have not been considered in this forecast.

In projecting total mined bitumen over the forecast period, the AER considered factors such as the crude oil price environment and the availability of refinery capacity.

By 2024, mined bitumen is expected to reach 258.2 10^3 m^3/d, a 2.5 per cent decrease over last year's forecast in which mined bitumen was expected to reach 264.9 10^3 m^3/d by 2023. This is mainly due to anticipated delays in projects previously assumed to be coming on production during the forecast period. Mined bitumen production compared to total bitumen production over the forecast period is illustrated in **Figure S3.8**, which shows that the percentage of mined bitumen to total production is expected to decrease from 45 per cent in 2014 to 40 per cent in 2024.

3.2.3.2 In Situ Bitumen

Similar to surface mining, the forecasted supply of in situ bitumen includes production from existing projects, expansions to existing projects, and new projects. The AER has considered all approved and applied for projects and has assumed that all existing projects will continue producing at their current or projected production levels over the forecast period.

Projects awaiting regulatory or corporate approval are generally discounted at 50 per cent, while those under construction or soon to be operating are discounted at rates reflective of past production of similar schemes. The projects considered for the forecast are shown in **Table S3.5**.

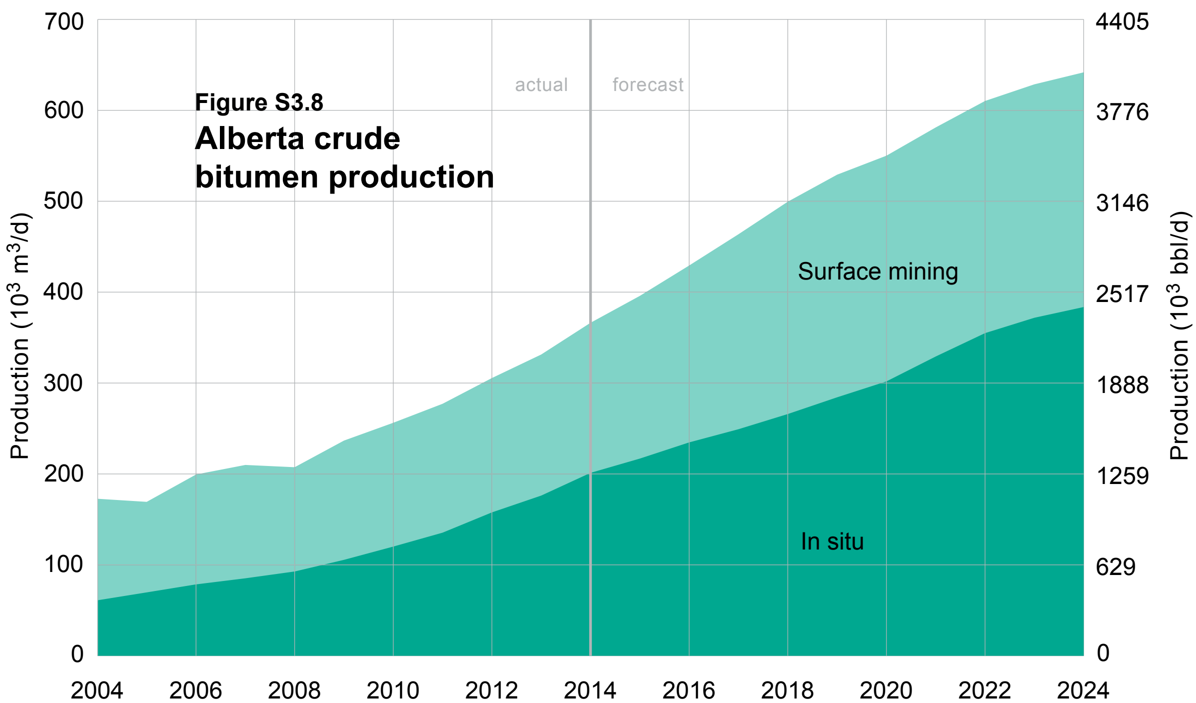


Table S3.4 Proposed surface-mined bitumen projects[a]

Company Project name	Capacity (10^3 m³/d)	Status
Alberta Oil Sands Project (Shell)		
Muskeg River expansion and debottlenecking	18.3	Approved
Jackpine Phase 1B	15.9	Approved
Jackpine Phase 2	15.9	Approved
Pierre River Phase 1	15.9	On hold
Pierre River Phase 2	15.9	On hold
CNRL		
Horizon Phase 2B	21.5	Construction
Horizon Phase 3	21.5	Construction
Suncor/Total E&P Canada		
Fort Hills Phase 1	25.4	Construction
Fort Hills debottleneck	3.2	Approved
Imperial Oil/Exxon Mobil		
Kearl Phase 2	17.5	Construction
Kearl Phase 1 debottleneck 1	4.5	Approved
Kearl Phase 1 debottleneck 2	5.0	Approved
Kearl Phase 2 debottleneck 1	4.5	Approved
Kearl Phase 2 debottleneck 2	5.0	Approved
Total E&P Canada/Suncor		
Joslyn (North)	15.9	On hold
Teck Resources Limited		
Frontier Phase 1	11.9	Application
Frontier Phase 2	13.3	Application
Frontier Phase 3	12.6	Application
Frontier Phase 4	6.3	Application

Source: AER and company releases.

[a] Projects are considered proposed until operational.

Table S3.5 Proposed in situ crude bitumen projects[a]

Company Project	Capacity (10^3 m^3/d)	Status
Athabasca Oil Sands Area		
Alberta Oil Sands		
Clearwater West	1.6	Application
Athabasca Oil		
Dover Clastics	1.9	Application
Hangingstone	1.9	Construction
BlackPearl		
Blackrod Commercial Phase 1–3	12.8	Application
Brion Energy (formerly Dover Operating Co.)		
Dover Phases 1–5 (approved in early 2014)	40.0	Approved
MacKay River Phase 1	5.6	Construction
MacKay River Phases 2–4	18.4	Approved
Cavalier		
Hoole Grand Rapids	1.6	Application
Cenovus		
Christina Lake Phase F	7.9	Construction
Christina Lake Phase G	7.9	Approved
Foster Creek Phase G	5.6	Construction
Foster Creek Phase H	5.6	Construction
Foster Creek Phase J	5.6	Application
Narrows Lake Phase 1	7.2	Construction
Narrows Lake Phase B and C	13.5	Approved
Pelican Lake Grand Rapids Phase A	1.4	Approved
Pelican Lake Grand Rapids Phases B and C	13.6	Application
Telephone Lake Phases A and B	14.4	Approved
CNRL		
Grouse Stage 1	6.4	Application
Kirby North Phase 1	6.4	Approved
Kirby North Phase 2	9.5	Construction
Connacher		
Great Divide Expansion Phases 1–3	3.8	Approved
ConocoPhillips		
Surmont Phase 2	18.8	Construction
Surmont Phase 3	21.5	Application
Devon		
Pike 1 Phases A–C	16.8	Approved
Walleye	1.4	Application
Grizzly Oil Sands		
Algar Phase 2	1.0	Approved
May River Phase 1	1.9	Approved
Harvest		
BlackGold Phase 2	3.2	Approved
Husky		
Sunrise Phase 1	9.5	Construction
Sunrise Phases 2–4	22.2	Approved
Imperial		
Aspen Phases 1–3	21.5	Application
Ivanhoe		
Tamarack Phases 1 and 2	3.2	On hold
JACOS		
Hangingstone Expansion	3.2	Construction
Koch Exploration		
Muskwa	1.6	Approved
Laricina		
Germain Phases 2–4	23.8	Application
Saleski Phase 1	2.0	Approved
Marathon		
Birchwood	1.9	Application
MEG		
Christina Lake Phases 3A–3C	23.8	Approved
Surmont Phases 1–3	19.0	Application
Nexen		
Kinosis Phase 1A	3.2	Construction
Kinosis Phases 1 and 2	19.0	Approved
Osum		
Sepiko Kesik	9.6	Application

(continued on next page)

Table S3.5 Proposed in situ crude bitumen projects[a] (continued)

Company / Project	Capacity (10^3 m^3/d)	Status
SilverWillow Energy		
Audet	1.9	Application
Statoil		
Kai Kos Dehseh Leismer Expansion	3.2	Approved
Kai Kos Dehseh Corner	6.4	On hold
Suncor		
Firebag Phases 5 and 6	19.8	Approved
Firebag Phases 3-6 Debottleneck	3.7	Approved
MacKay Phase 2	3.2	Approved
Sunshine Oilsands		
Legend Lake	1.6	Application
Thickwood	1.6	Approved
West Ells Phases A1	0.8	Construction
West Ells Phases A2	0.8	Approved
Surmont Energy		
Wildwood	1.9	Application
Value Creation		
Terre de Grace Phase 1	1.6	On hold
Advanced TriStar	11.9	Application
Cold Lake Oil Sands Area		
Husky		
Caribou Lake Phase 1	1.6	Approved
Imperial		
Cold Lake Phases 14–16	4.8	Construction
Baytex Energy Corp.		
Gemini Phase 2 (incl. pilot)	0.8	Approved
Osum		
Taiga Phases 1-3	7.2	Approved
Pengrowth		
Lindbergh Phase 1	1.8	Construction
Lindbergh Phase 2	2.8	Application
Orion (Hilda Lake) Phase 2	1.6	Approved
Peace River Oil Sands Area		
Penn West		
Seal Main Commercial	1.6	Application
Shell Peace River		
Carmon Creek Phase 1	6.3	Construction
Carmon Creek Phase 2	6.3	Approved

Source: AER and company releases.

[a] Projects are considered proposed until operational.

To this projection, the AER has added crude bitumen production from new and expanded schemes. The production forecasts for future crude bitumen projects take into account past experiences of similar schemes, project modifications, crude oil and natural gas prices, light crude and bitumen price differentials, and the ability of North American markets to absorb the increased volumes.

As shown in **Figure S3.8**, the AER expects in situ crude bitumen production to increase to 383.6 10^3 m^3/d by 2024, a slight increase compared to last year's forecast of 379.4 10^3 m^3/d by 2023. This growth is mainly because of new projects being added. However, compared to last year's forecast, this is slightly lower overall due to project delays. By 2024, in situ bitumen is expected to account for 60 per cent of total bitumen produced. Factors that may affect the pace of development were considered in the forecast, such as the availability of labour and equipment.

In 2014, approximately 10.5 per cent of in situ production in Alberta was upgraded, mostly from Suncor's Firebag project. The percentage of in situ bitumen being upgraded is expected to decline by 2024 as the amount of nonupgraded bitumen production increases.

3.2.3.3 Upgraded Bitumen

In its forecast of upgraded bitumen production, the AER includes existing production from the facilities and existing expansions of Suncor, Syncrude, Shell, CNRL, and Nexen and new production expected from the new projects and planned expansions listed in **Table S3.6**. The North West upgrader is still expected to come on stream in 2018. However, phase 2 of Nexen's Long Lake project has been placed on hold and is not included in the forecast period. Production from future upgrading projects considers the high cost of engineering and

Table S3.6 Proposed upgraded bitumen projects

Company Project	Upgrading capacity (10^3 m^3/d)	Status
Athabasca Region		
CNRL		
Horizon Phases 2B and 3	19.9	Construction
Nexen		
Long Lake Phase 2	9.3	On hold
Value Creation		
Terre de Grace	1.3	Approved
Advanced TriStar	10.2	Application
Industrial Heartland Region		
North West Upgrading		
NW Upgrader Phase 1	7.9	Construction
NW Upgrader Phase 2 and 3	15.8	Approved

Source: AER and company releases.

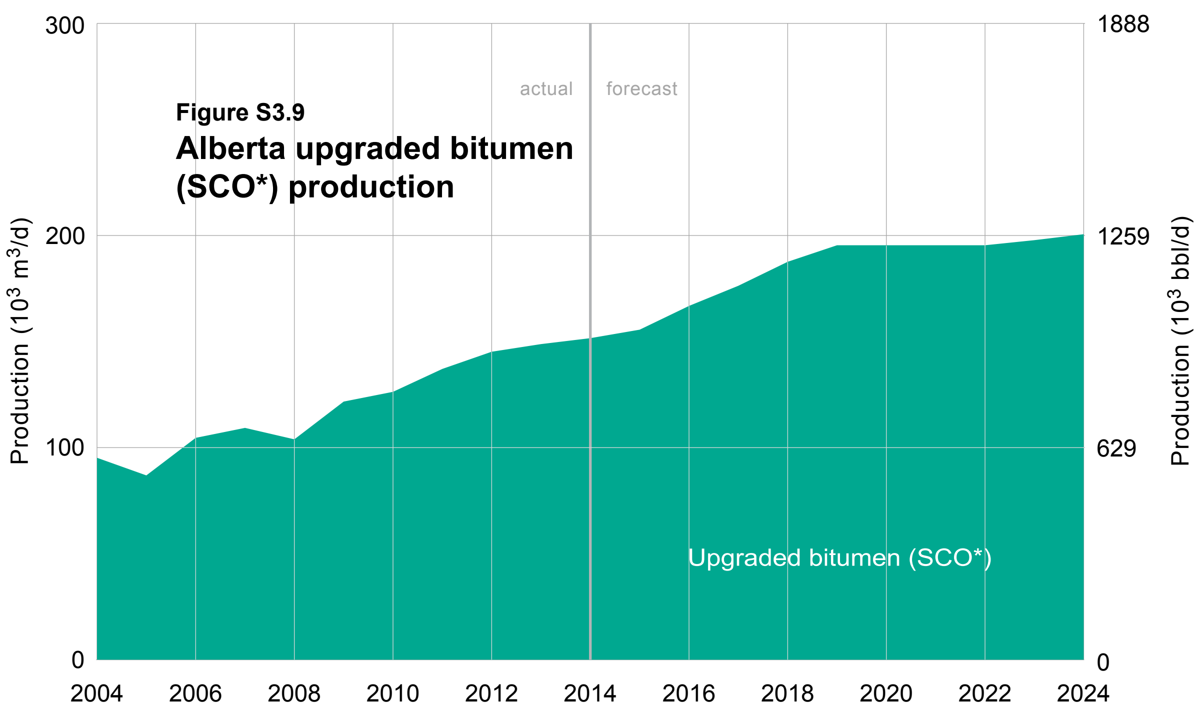
materials and the substantial amount of skilled labour required to expand existing and new projects. The AER also recognizes that other key factors, such as oil price forecasts, the price differential between light crude oil and bitumen, the length of the construction period, and the market penetration of new upgraded volumes, will affect project timing.

Over the forecast period, the percentage of crude bitumen being upgraded is expected to decline from 47.4 per cent of total crude bitumen in 2014 to 36.7 per cent in 2024 due to the growth in production of bitumen outpacing the growth in upgrading capacity.

Figure S3.9 shows the AER's projection of upgraded bitumen production, which is expected to increase from 151.6 10^3 m^3/d in 2014 to 155.6 10^3 m^3/d in 2015. This increase assumes operators will be able to reach their planned production targets. Production is forecast to increase to 200.6 10^3 m^3/d by 2024, a 4 percent decrease from last year's forecast of 208.7 10^3 m^3/d by 2023. This decline is the result of some delays in previously anticipated project expansions, such as Nexen's Long Lake Phase 2 and Syncrude's Aurora expansion.

3.2.4 Demand for Upgraded and Nonupgraded Bitumen

Upgraded bitumen (synthetic crude oil) is mostly light sweet crude oil while blended bitumen (nonupgraded bitumen with diluent) is a heavy crude oil. Consequently, Alberta's crude bitumen and conventional crude oil production often services the same refineries and uses the same transportation infrastructure to make it to market. As such, when considering existing and potential future markets for bitumen and upgraded bitumen, production of conventional crude oils, especially heavier crude oils, must be accounted for in the analysis.



*Synthetic crude oil.

Overall demand for Alberta upgraded bitumen and blended bitumen is influenced by many factors, including the price differential between light and heavy crude oil, the expansion of refineries currently processing upgraded bitumen and blended bitumen, the altering of current light crude oil refineries to process upgraded bitumen and blended bitumen, and the availability and price of diluent for shipping blended bitumen. The supply forecast relies on a growth in demand in Alberta and the ability of Alberta production to supply export markets.

In 2014, the four refineries in Alberta, with a total Alberta throughput of 73 10^3 m^3/d, used 49.4 10^3 m^3/d of upgraded bitumen and 3.7 10^3 m^3/d of nonupgraded bitumen. Additional demand for upgraded bitumen as diesel fuel and plant fuel accounted for 6.7 10^3 m^3/d in 2014, compared with 5.5 10^3 m^3/d in 2013, an increase of 22 per cent. Alberta refineries consumed 32.6 per cent of Alberta upgraded bitumen production and 1.9 per cent of nonupgraded bitumen production in 2014, which is very similar to 2013 levels. Overall, total Alberta demand for upgraded and nonupgraded bitumen was 59.4 10^3 m^3/d in 2014, which is a 7.2 per cent increase from 55.5 10^3 m^3/d in 2013.

Upgraded bitumen is also used by oil sands upgraders as fuel for transportation and as plant fuel. Suncor reports that it sells bulk diesel fuel to companies that transport upgraded bitumen to markets in tanker trucks. Suncor sells diesel fuel supplied from its oil sands operation in the Fort McMurray area. In 2014, the sale of refined upgraded bitumen as diesel fuel oil accounted for about 8.7 per cent of Alberta upgraded bitumen demand, up from 7 per cent in 2013.

Beyond the addition of the North West upgrader, the AER assumes that there will only be limited growth in demand in Alberta over the forecast period. As a result, the anticipated growth in supply will be removed from the province to service other markets.

Traditionally, removals from Alberta service the U.S. Rocky Mountain and the U.S. Midwest regions, with a total refining capacity of 705.6 10^3 m^3/d. In addition to partially supplying western Canada's eight refineries, with a total capacity of 108 10^3 m^3/d, Alberta crude oil also supplies four refineries in the Sarnia area of eastern Canada, with a total capacity of 75.2 10^3 m^3/d. In 2014, removals of upgraded bitumen and nonupgraded bitumen amounted to 95.4 10^3 m^3/d and 189.4 10^3 m^3/d, respectively.

Resurgent light oil production in other supply basins in North America has led to increased competition in what have traditionally been the largest export markets for Alberta upgraded and nonupgraded bitumen. As such, there is increasing interest in accessing other market regions, such as the U.S. Gulf Coast, with a refining capacity of 1454.7 10^3 m^3/d. Further access to this region is of particular importance for nonupgraded bitumen, as this region has refineries capable of handling heavier crude oils. Transportation is going to play a key role in accessing additional markets as Alberta producers seek to move beyond their traditional markets. Pipeline and rail transportation is discussed in **Section 9.1.1** and **Section 9.1.2**.

While the inventory issues at Cushing, Oklahoma, have eased with the start-up of the southern leg of TransCanada's Keystone XL project (the Gulf Coast project) and the expansion of the Seaway pipeline, limited takeaway capacity has continued to affect Enbridge's ability to take advantage of unused capacity on its Mainline system before it reaches Superior, Wisconsin. This is expected to change as pipeline projects aimed at expanding capacity on the Mainline and Lakehead systems are pursued. These projects would include an expansion of the Alberta Clipper line and the Southern Access line, in addition to the proposed Flanagan South project, which would mirror the Spearhead pipeline. In addition to Enbridge's projects aimed at accessing the Gulf Coast markets, completion of the northern leg of TransCanada's Keystone XL project, if approved, would give Alberta producers direct access to the U.S. Gulf Coast markets.

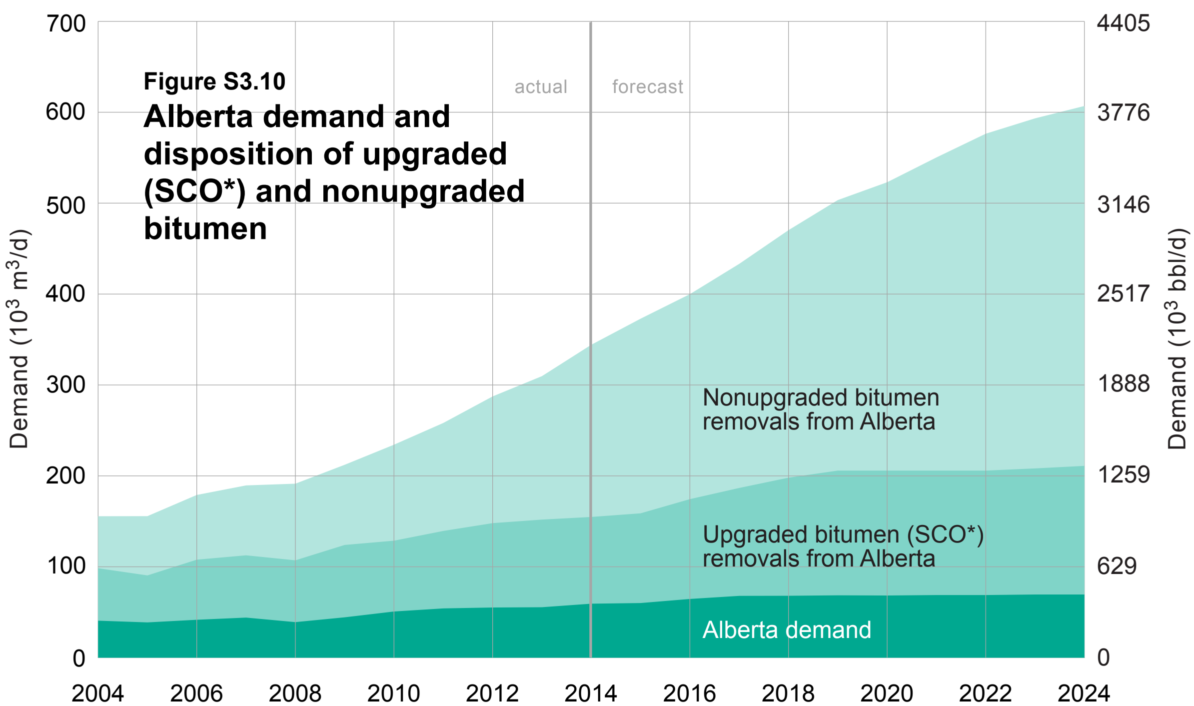
Beyond accessing the Gulf Coast markets, considerable attention is being given to accessing markets not traditionally served by Alberta production, such as the East Coast, West Coast, and Asian markets. Among the projects aimed at providing access to the East Coast is the proposed conversion of a portion of TransCanada's Mainline natural gas system to oil service, dubbed the Energy East project, and the proposed reversal of Lines 9A and 9B by Enbridge. Projects aimed at accessing the West Coast and points beyond include Enbridge's proposed Northern Gateway pipeline and Kinder Morgan's proposed expansion to its Trans Mountain pipeline. Both projects would give port access for Alberta production allowing it to access international markets. More information regarding Alberta's petroleum pipelines can be found in **Section 9.1.1.1**.

Rail shipments represent a small but significant portion of total volumes of oil moved from Alberta. At present, rail is primarily being used to service projects with limited or no access to pipeline capacity. However, this is expected to change in the near term as producers such as Southern Pacific, MEG Energy, and Cenovus contract rail transport to secure transportation for their production and to access higher value markets. In the long term, however, growth in shipments of oil by rail will depend on several factors, such as the differential between WTI and Western Canadian Select (WCS), the availability and supply of diluent, pipeline capacity, cost of rail transportation, and the development of handling facilities to fill railcars with bitumen.

In late 2013, Canexus finished expansions to its rail terminal capacity at its Bruderheim facility (northeast of Edmonton) where, in late 2014, Canada's first crude bitumen unit train was loaded. Keyera's South Cheecham rail and truck terminal (southeast of Fort McMurray) provides oil sands producers' services within the Athabasca oil sands area. These services include handling diluent, diluted bitumen (dilbit), solvents, and NGLs delivered to the terminal by pipeline, truck, and rail. Gibson's Hardisty Rail Terminal started operating in June 2014 and Kinder Morgan's Edmonton Rail Terminal is slated to open in early 2015.

Over the past five years, North America has witnessed a sharp increase in oil production. The new supplies have mainly come from shale oil resources in the United States and from Canada's oil sands. This increase in supply has resulted in a decline of oil imported from overseas into the United States. Currently crude bitumen removals are only sent to the United States. To expand into other markets, industry is proposing ex-Alberta options. With the Energy East pipeline proposal, potential markets for crude bitumen would be eastern Canada and Europe. To date, very little Alberta oil has been sold to European countries, with a few cargos shipped in 2014 as experimental shipments to test refining capability.

Considering the general growth in Alberta demand and the North West upgrader coming on production in 2018, it is expected that by 2024, Alberta demand for upgraded and nonupgraded bitumen will increase to about 69.5 10^3 m^3/d. It is projected that, on average, upgraded bitumen will account for approximately 86 per cent of total Alberta marketable bitumen demand, and nonupgraded bitumen will account for about 14 per cent throughout the forecast period. Removals of upgraded bitumen from Alberta are expected to increase from 95.4 10^3 m^3/d in 2014 to 141.5 10^3 m^3/d in 2024, with removals of nonupgraded bitumen increasing from 189.4 10^3 m^3/d to 395.9 10^3 m^3/d over the same period. Alberta demand and removals from Alberta are shown in **Figure S3.10.**



*Synthetic crude oil.

HIGHLIGHTS

Remaining established reserves increased by 2 per cent in 2014 to 288 million cubic metres.

Reserves additions from new drilling and enhanced recovery schemes replaced 111 per cent of production in 2014.

Total crude oil production from all wells increased 1 per cent in 2014 over 2013 levels.

There were 2577 oil wells placed on production in 2014, a decrease of 7 per cent from 2013.

4 CRUDE OIL

In Alberta, crude oil (also known as conventional oil) is deemed to be oil produced outside the oil sands areas or, if within the oil sands areas, from formations other than the Mannville or Woodbend. Crude oil is classified as light-medium if its density is less than 900 kilograms per cubic metre (kg/m^3) or as heavy if its density is 900 kg/m^3 or greater.

The AER refers to unconventional crude oil as "tight" oil, that is oil found in low-permeability rock, such as sandstone, siltstone, shale, and carbonates. The AER, however, does not separately estimate or report tight oil reserves or production for historical, regulatory, and administrative reasons. It is often difficult or impossible to separate the tight portion of the reserves or production of a conventional reservoir and, therefore, any unconventional tight oil volumes are included within the AER's conventional crude oil reserves and production reporting.

Crude bitumen from Alberta's oil sands, discussed separately in **Section 3**, is not considered unconventional oil.

4.1 Reserves of Crude Oil

4.1.1 Provincial Summary

The AER estimates the remaining established reserves of conventional crude oil in Alberta to be 288.2 million cubic metres (10^6 m^3)—more than one third of Canada's remaining conventional reserves. This is a year-over-year increase of 4.8 10^6 m^3, or 1.6 per cent, and is a result of all reserves additions less production during 2014.

Table R4.1 shows the changes in Alberta's reserves and production of light-medium and heavy crude oil as of December 31, 2014, while **Figure R4.1** shows the province's remaining conventional oil reserves over time. Remaining reserves are now 24 per cent of the peak reserves of 1223 10^6 m^3, which was set in 1969.

4.1.2 In-Place Resources

The total initial in-place and remaining in-place resources for conventional oil in Alberta stand at 12 927 10^6 m^3 and 10 205 10^6 m^3, respectively. This remaining in-place resource represents a substantial potential for increased recovery through enhanced oil recovery (EOR) or new drilling and completion techniques, such as high-density drilling and multistage fracturing technology. On average, 23 per cent of the total oil in place in these pools is expected to be recovered with today's technology. Additionally, the shale- and siltstone-hosted hydrocarbon resources

Table R4.1 Reserves and production change highlights (10^6 m^3)

	2014	2013	Change
Initial established reserves[a]			
Light-medium	2 589.3	2 562.9	+26.4
Heavy	420.7	407.0	+13.7
Total	**3 010.0**	**2 969.9**	**+40.1**
Cumulative production[b]			
Light-medium	2 371.2	2 345.7	+25.5
Heavy	350.6	340.7	+9.9
Total	**2 721.8**	**2 686.4**	**+35.4**[b]
Remaining established reserves[a]			
Light-medium	218.1	217.2	+0.9
Heavy	70.1	66.2	+3.9
Total	**288.2**	**283.4**	**+4.8**
	(1 814 10^6 bbl)[c]	(1 783 10^6 bbl)[c]	(30 10^6 bbl)[c]
Annual production			
Light-medium	25.6	24.9	+0.7
Heavy	8.6	8.9	-0.3
Total	**34.2**	**33.8**	**+0.4**

[a] Any discrepancies are due to rounding.

[b] May differ from annual production due to amendments to reported production and other reasons.

[c] bbl = barrels.

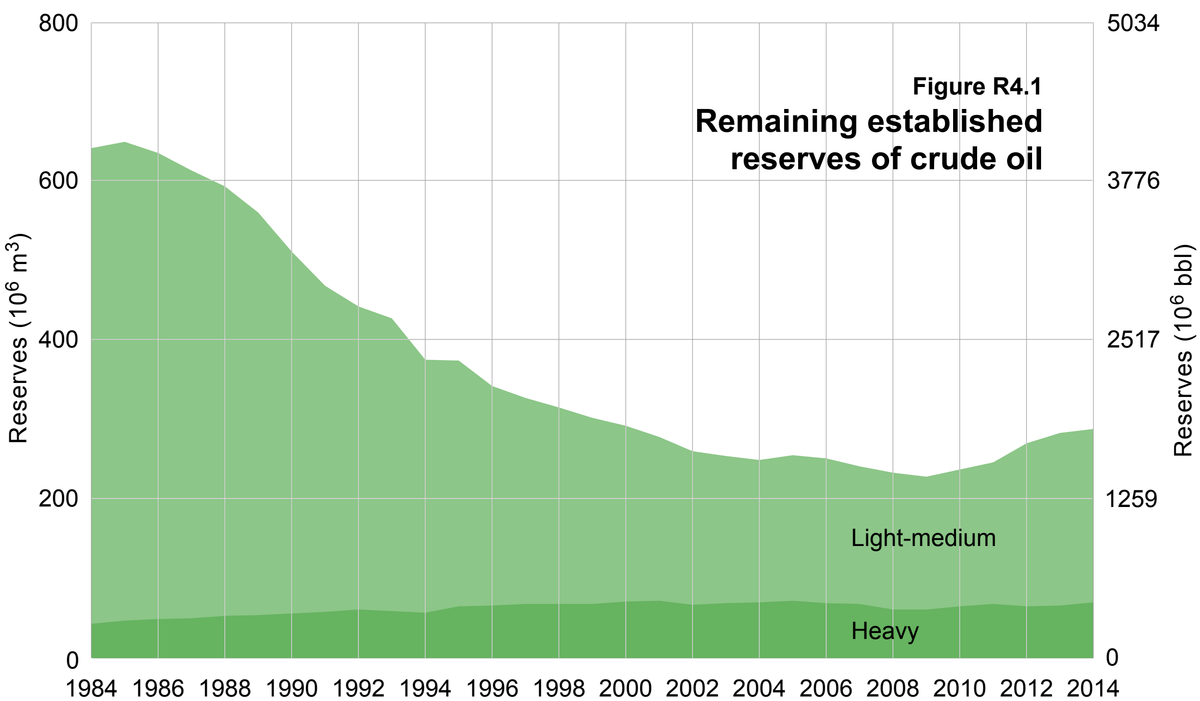


Figure R4.1
Remaining established reserves of crude oil

study described in **Section 2.2.2** identified 67 320 10^6 m^3 of unconventional in-place shale oil resources in six key shale formations in Alberta.

4.1.3 Established Reserves

As of December 31, 2014, the initial established reserves was 3010 10^6 m^3. The initial established reserves attributed to the 224 new oil pools defined in 2014 totalled 4.3 10^6 m^3 (an average of 19 thousand [10^3] m^3 per pool), down from 4.8 10^6 m^3 in 2013. Many of the 224 new oil pools can be attributed to the exploration for and expansion of reservoirs with low permeability. A significant number of these pools are classified administratively as single well pools but have the potential to be reclassified, based on development, into multiwell pools. **Table R4.2** breaks down the changes to initial established reserves in 2014 into the following categories: new discoveries, development of existing pools, new and expansions to EOR schemes, and revisions to existing reserves. **Figure R4.2** shows the history of additions and net revisions to reserves. Net revisions represent the sum of all negative and positive revisions to pool reserves made over the year.

Table R4.2 Breakdown of changes in crude oil initial established reserves (10^6 m^3)

	Light-medium	Heavy	Total[a]
New discoveries	3.4	0.9	**4.3**
Development of existing pools	20.9	5.8	**26.7**
Enhanced recovery (new/expansions)	3.8	3.0	**6.8**
Revisions	−1.6	+3.9	**+2.3**
Total[a]	**+26.5**	**+13.6**	**+40.1**

[a] Any discrepancies are due to rounding.

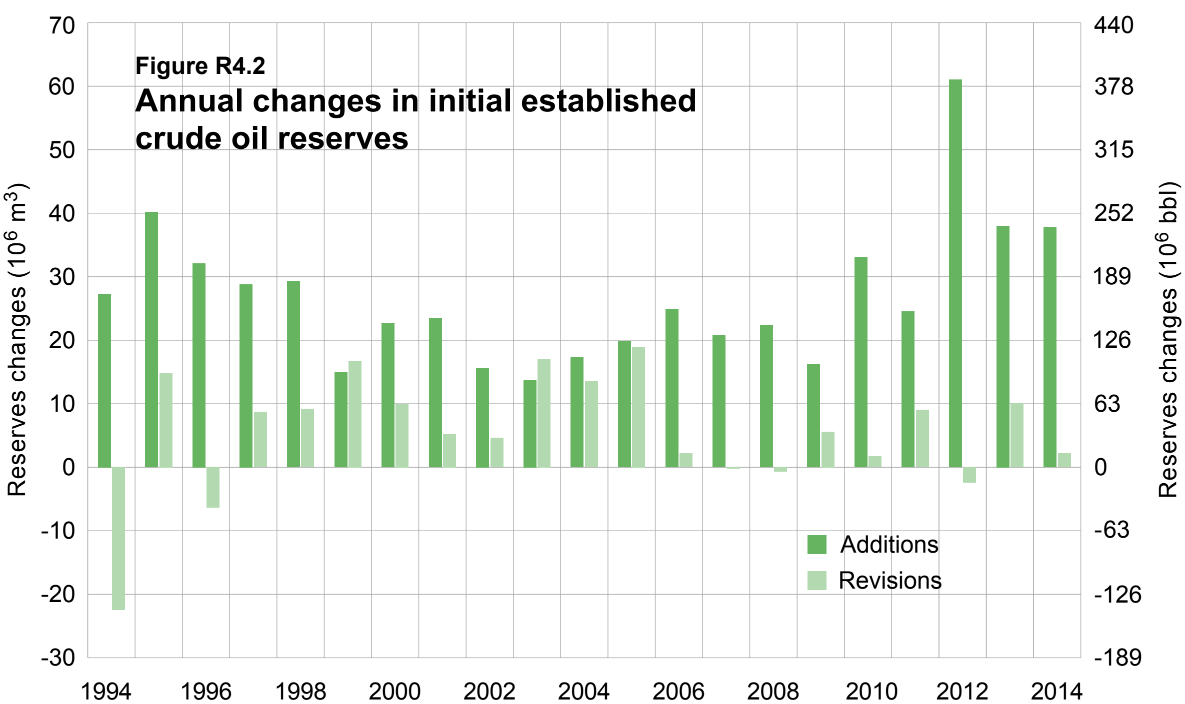
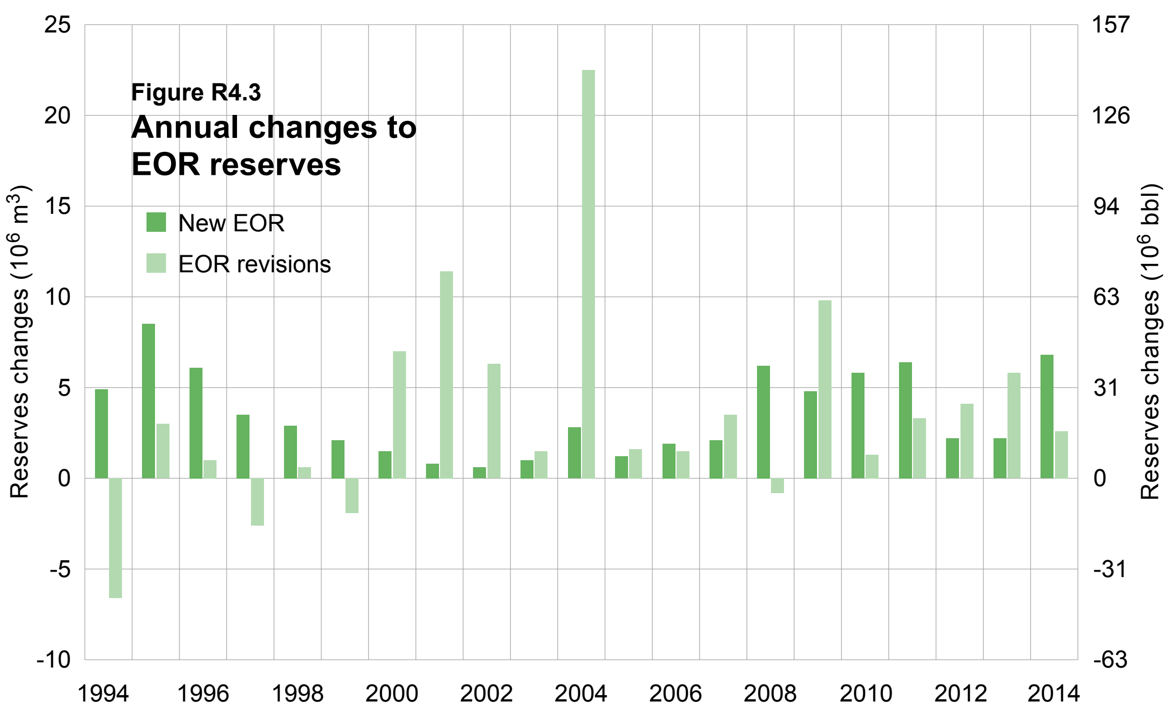


Figure R4.2
Annual changes in initial established crude oil reserves

In 2014, the AER processed 37 applications for new EOR schemes, down slightly from the 41 processed in 2013. These new schemes, along with expansions to existing EOR schemes, resulted in reserves additions totalling 6.8 10^6 m^3, compared with 2.2 10^6 m^3 in 2013 (**Figure R4.3**). Development of existing pools added established reserves of 26.7 10^6 m^3. This is discussed in more detail in **Section 4.1.3.1**. Total reserves growth from new drilling plus new and expanded EOR schemes (excluding revisions) amounted to 37.8 10^6 m^3, replacing 111 per cent of the 34.2 10^6 m^3 total conventional crude oil production in Alberta. This is comparable to 112 per cent in 2013 and the previous five-year average replacement ratio of about 116 per cent. Revisions to existing reserves resulted in an overall net positive change of 2.3 10^6 m^3. The total increase in initial established reserves for 2014 amounted to 40.1 10^6 m^3, compared with 48.1 10^6 m^3 in 2013. **Table B.3** in **Appendix B** gives a history of conventional oil reserves growth and cumulative production from 1968 to 2014.

As of December 31, 2014, oil reserves were assigned to 11 176 light-medium and 2981 heavy crude oil pools in the province, up from the respective 2013 numbers of 11 073 and 2939. While some of these pools contain thousands of wells, most consist of a single well. About 70 per cent of the province's remaining oil reserves are recoverable from the largest 3 per cent of pools (400 pools), a majority of which were discovered before 1980. The largest of these pools in terms of remaining reserves are, in order of decreasing size, Pembina Cardium, Swan Hills Commingled Pool 001, Turner Valley Rundle, Willesden Green Commingled Pool 007, and Ferrier Commingled Pool 001.

While the median pool size of new discoveries has consistently been less than 10 10^3 m^3 since the mid-1970s, the average size has declined from 155 10^3 m^3 in 1970 to about 25 10^3 m^3 in recent years. The largest oil pools discovered over the past ten years are the Pembina Cardium JJJ Pool, the Ferguson Lwr Banff-Exshaw-



BV B Pool, and the Elnora Nisku B Pool (all revised in 2014), with currently booked remaining reserves of 2085 10^6 m^3, 1966 10^6 m^3, and 1825 10^6 m^3, respectively.

A detailed pool-by-pool list of reservoir parameters and reserves data for all of Alberta's oil pools is available as an electronic data file from the AER's Order Fulfillment Team (see **Appendix C**).

4.1.3.1 Largest Reserves Changes

Table R4.3 lists pools with the largest reserves changes in 2014. The most significant change was to the Provost Commingled MFP 9515, which saw initial established reserves increase by 2516 10^3 m^3 to 8501 10^3 m^3 as a result of pool development. There continues to be a potential for significant reserves growth from new horizontal drilling in the Cardium Formation at Pembina, Willesden Green, and other surrounding fields. Horizontal wells using multistage fracturing technology are being drilled on the periphery of the main pools, into reservoir areas where permeability declines to generally less than 1 millidarcy (mD) as a result of a change to a shalier facies. The largest negative revision to any pool was in the Lloydminster Sparky G Pool, which decreased by 636 10^3 m^3.

4.1.3.2 Distribution by Recovery Mechanism

The overall recovery efficiency for Alberta's conventional crude oil averages 23.3 per cent based on the total initial volume in-place and the initial established reserves of 12 927 10^6 m^3 and 3010 10^6 m^3, respectively. This average overall recovery has been slowly declining over the last decade from an average of 26.6 per cent in 2004. The decline in recovery efficiency is mainly due to the development of reservoirs with lower permeability and porosity within the province. These types of reservoirs have limited potential for enhanced recovery and, therefore, diminish the overall provincial recovery factor. **Figure R4.4** and **Table R4.4** show the distribution of in-place volumes and reserves by recovery mechanism and crude oil classification.

In light-medium pools under waterflood, recovery increased from an average of 15 per cent under primary depletion to an average of 28 per cent under waterflood. Pools under solvent flood, on average, recovered 12 per cent more than projected theoretical waterflood recovery. Additionally, solvent flooding, as well as gas flooding, is usually only undertaken in pools with better quality reservoir characteristics, as demonstrated by the markedly higher average primary recovery factors.

Primary recovery in heavy crude pools has increased from an average of 8 per cent in 1990 to 11 per cent in 2014 because of improved water handling, increased drilling density, and the use of horizontal wells using multistage fracturing technology. Incremental recovery from all waterflood projects represents about 18 per cent of the province's initial established reserves, while polymer floods are projected to add 11 per cent to the province's recoverable reserves. Alkali surfactant polymer (ASP) flooding has proven to be very effective, typically adding 3 to 10 per cent recovery over waterflood. Polymer flooding is used mainly in heavy oil pools where it is most effective.

4.1.3.3 Distribution by Geological Formation and Area

The distribution of reserves by geological period (**Figure R4.5**) shows that the Cretaceous and Upper Devonian ages are the major sources for remaining conventional oil. Most of the initial and remaining reserves are in the central and foothills regions of the province, with Petroleum Services Association of Canada (PSAC) Areas 2 and 5, containing about 60 per cent of the initial reserves and 50 per cent of remaining reserves between them.

Table R4.3 Major oil reserves changes, 2014

	Initial established reserves (10^3 m^3)		
Pool	**2014**	**Change**	**Main reason for change**
Provost Commingled MFP9515	8 501	+2 516	Pool development
Medicine Hat Glauconitic C	7 559	+1 280	Reassessment of reserves
Lloydminster Lloydminster M	1 624	+1 097	New waterflood scheme and reassessment of reserves
Ante Creek North Triassic E	3 866	+983	Pool development
Provost Cummings I	7 302	+958	Pool development and reassessment of reserves
Mooney Bluesky A	3 251	+788	Pool development
Kaybob Triassic G	3 128	+786	Pool development
Elnora Nisku B	2 084	+756	New waterflood scheme and pool development
Pembina Cardium JJJ	2 600	+685	Pool development
Elmworth Dunvegan JJJ	867	+680	Pool development
Lloydminster Sparky G	2 288	-636	Removal of waterflood scheme and reassessment of reserves
Hythe Halfway F	1 071	+608	Pool development
Leduc-Woodbend D-2 A	15 148	+560	Pool development
Bantry Mannville A	11 610	−560	Reassessment of reserves
Waskahigan Montney F	1 017	+496	Pool development
Pembina Commingled Pool 011	996	+486	New waterflood scheme and pool development
Swimming McLaren D	1 259	+446	Pool development
Mannville Upper Mannville B	1 105	+419	New waterflood scheme
Wildmere Commingled Pool 003	9 476	+413	Pool development
Brazeau River Belly River C6C	717	+404	Pool development
Mikwan D-2 S	501	+391	Pool development
Penny Baron A	1 603	+379	Reassessment of reserves
Wapiti Commingled Pool 001	2 699	+377	Pool development
Taber South Mannville A	2 900	+370	Reassessment of reserves
Roxana Montney H	829	+357	New waterflood scheme
Pouce Coupe South Commingled Pool 012	1 230	+335	Pool development and reassessment of reserves

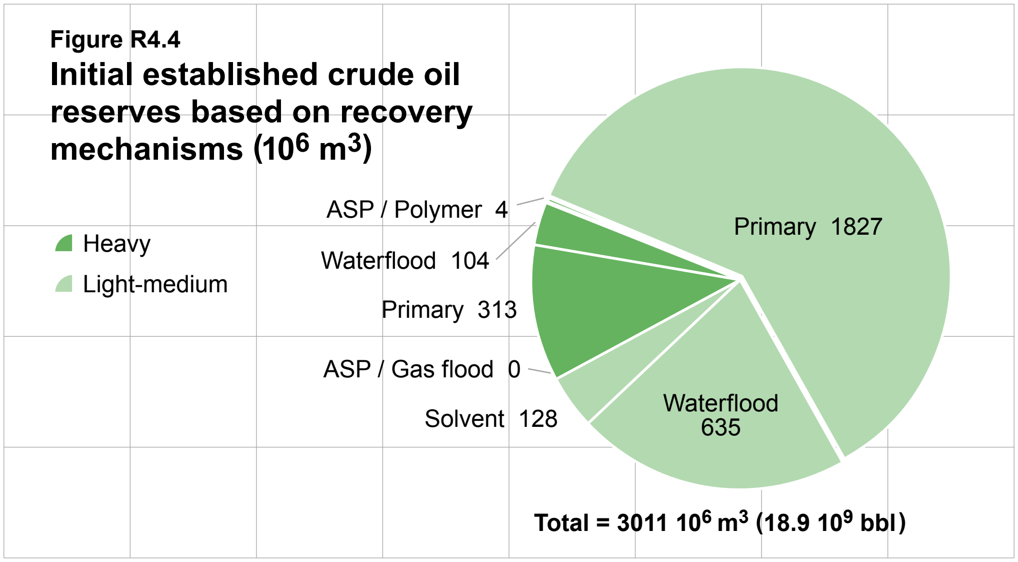
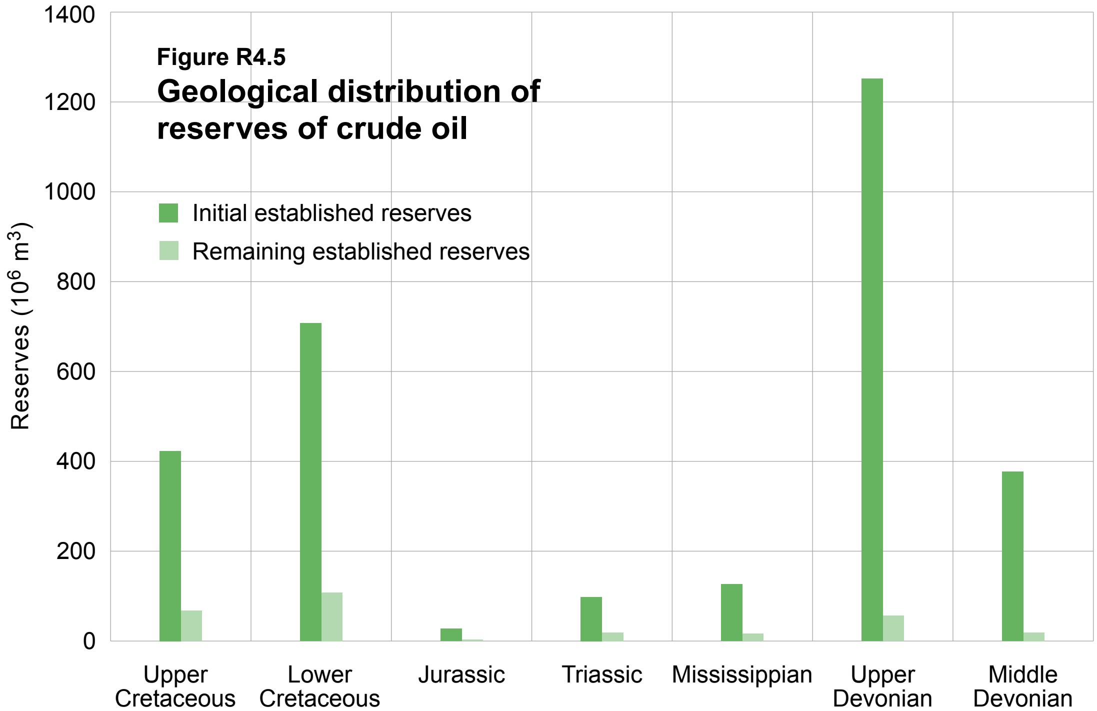


Table R4.4 Conventional crude oil reserves by recovery mechanism as of December 31, 2014

Crude oil type and pool type	Initial volume in-place (10^6 m^3)	Initial established reserves (10^6 m^3)				Average recovery (%)			
		Primary	Water/ gas flood	Solvent flood	Total	Primary	Water/ gas flood	Solvent flood	Total
Light-medium									
Primary	5 548	994	0	0	**994**	18	-	-	**18**
Waterflood	3 470	521	445	0	**966**	15	13	-	**28**
Solvent flood	1 033	273	177	128	**578**	26	17	12	**56**
ASP	9	1	3	0	**4**	11	33	-	**44**
Gas flood	145	38	10	0	**48**	26	7	-	**33**
Heavy									
Primary	1 931	215	0	0	**215**	11	-	-	**11**
Waterflood	720	91	94	0	**185**	13	13	-	**26**
Polymer	32	3	5	0	**8**	9	16	0	**25**
ASP	39	4	5	4	**13**	10	13	10	**33**
Total	**12 927**	**2 140**	**739**	**132**	**3 011**	**17**	**6**	**1**	**23**
Percentage of total initial established reserves		71%	25%	4%	**100%**				



4.1.3.4 Geological Plays of Alberta

A geological play can be defined as a set of known or estimated oil or gas accumulations (discrete and continuous) within a petroleum system (a linked assemblage of source rock, migration routes, and ultimate traps) sharing similar geological, geographic, and temporal properties, such as source rock, migration pathways, timing, trapping mechanism, and hydrocarbon type. Estimates of volumes of hydrocarbon can be quantified for petroleum systems. The Western Canada Sedimentary Basin contains at least eight petroleum systems (as discussed in **Section 2.1.2**).

Each petroleum system has a number of stratigraphic intervals that can be subdivided into geological plays. The geographic limit of each play represents the limits of the geological elements that define the play. An example of a geological play in Alberta would be the Pembina Nisku Formation pinnacle-reef sour-gas play.

The AER is currently in the process of evaluating a number of geological plays based on priority, for the purpose of generating estimates of resources and reserves for each geological play. Numerous factors are considered in determining priority for review, such as industry activity, environmental impact, and safety. At this time, the AER is focusing on a number of plays within the Cardium, Montney, and Duvernay stratigraphic intervals.

4.1.3.5 Oil Reserves Methodology

The process of quantifying reserves is governed by many geological, engineering, and economic considerations. Initially, there is a higher uncertainty in the reserves estimates, but this uncertainty decreases over the life of a pool as more information becomes available and actual production is observed and analyzed. The earliest reserves estimates are usually based on volumetric estimation. An estimate of bulk rock volume is based on net pay isopach maps derived primarily from geological evaluation of well log data. This is combined with data gathered on rock properties, such as porosity and water saturation, to determine the oil in-place at reservoir conditions. Areal assignments for new single-well oil pools range from 64 hectares (ha) for light-medium oil producing from regionally correlatable geological units to 32 ha or less for heavy oil pools and small reef structures.

Converting volume in-place to standard conditions at the surface requires applying oil shrinkage data obtained from a pressure, volume, and temperature (PVT) analysis. A recovery factor is applied to the in-place volume to yield recoverable reserves. Oil recovery factors vary depending on oil viscosity, rock permeability, drilling density, rock wettability, reservoir heterogeneity, and reservoir-drive mechanism. Recoveries range from 5 per cent for heavy oils to over 50 per cent for light-medium oils producing from highly permeable reefs with full pressure support from an active underlying aquifer. Provincially, 23 per cent of the in-place resource is recovered on average.

Once there are sufficient pressure and production data, material balance or production decline methods can be used as an alternative to volumetric estimation to determine in-place resources. Analysis by material balance is seldom used as it requires good pressure and PVT data. A production decline analysis, therefore, is the primary method for determining recoverable reserves. When combined with a volumetric estimate of the in-place resource, it also gives a realistic estimate of the pool's recovery efficiency.

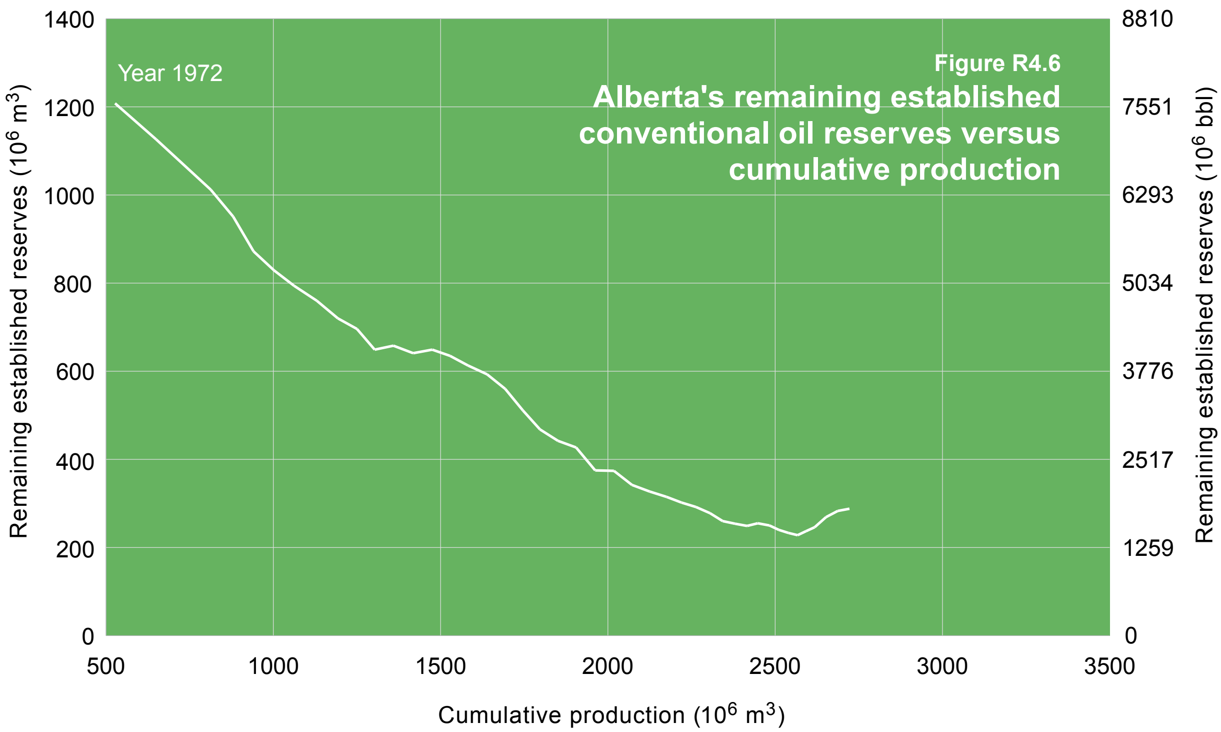
Secondary recovery techniques using artificial means of adding energy to a reservoir by water or gas injection can considerably increase oil recoveries. Less common tertiary recovery techniques may be applied by injecting fluids that are miscible with the reservoir oil at high pressures. This improves recovery efficiency by reducing the residual oil saturation at abandonment. However, irregularities in rock quality can lead to channelling, which causes low sweep efficiency and oil to be bypassed in some areas in the pool.

Incremental recovery over primary depletion is estimated for pools approved for waterflood and is displayed separately in the AER's oil reserves database. To accommodate the Alberta government's royalty incentive programs, incremental recovery over an estimated base-case waterflood recovery is determined for tertiary schemes. Typically a base-case waterflood recovery is estimated even in cases where no waterflood was implemented before the solvent flood.

Reserve numbers published by the AER are estimates for in-place, recoverable reserves. Recovery factors are based on the most reasonable interpretation of available information from volumetric, production decline, and material balance methods.

4.1.4 Ultimate Potential

In 1994, based on the geological prospects at that time, the AER estimated the ultimate potential of conventional crude oil to be 3130 10^6 m^3. This estimate only includes conventional reservoirs and does not include oil from tight oil or shale oil plays. Refer to **Section 2.3.3** for a discussion of the ultimate potential for oil within the shale and siltstone portion of the Montney Formation in Alberta. **Figure R4.6** illustrates the historical decline in remaining established reserves relative to cumulative oil production.



4.2 Supply of and Demand for Crude Oil

In projecting crude oil supply, the AER considers two components: expected crude oil production from existing producing wells and expected production from new wells placed on production. Total forecast production of crude oil is the sum of these two components. The AER also takes into account its estimates of the remaining established and yet-to-be established reserves of crude oil in the province. Demand for crude oil in Alberta is based on provincial refinery capacity and use. Alberta crude oil supply in excess of Alberta demand is marketed outside the province.

Starting with this year's report, crude oil production data will be classified into four density categories instead of the two categories (light-medium and heavy) used for reserves estimations:

- ultra-heavy crude oil (density equal to 925 kg/m^3 or greater)
- heavy crude oil (density equal to 900 and less than 925 kg/m^3)
- medium crude oil (density equal to 850 and less than 900 kg/m^3)
- light crude oil (density less than 850 kg/m^3)

In previous years, conventional crude oil production had been split into two categories: light-medium or heavy crude oil. This year, light-medium crude oil production has been separated into light crude oil and medium crude oil. Heavy crude oil production has been separated into heavy crude oil and ultra-heavy crude oil.

In addition, the definition of a producing well will now include drain wells.[1] As a result, historical well counts have been revised and are higher than in previous years. Well productivity calculations are also affected by this new definition of producing wells, as discussed later.

Table S4.1 shows crude oil production from all wells (crude oil, natural gas, and other wells) and shows crude oil wells that came on production in 2013 and 2014, but does not include natural gas and other wells that may have produced oil.

4.2.1 Crude Oil Production – 2014

Starting in 2010, total crude oil production in Alberta reversed the downward trend that has been the norm since the early 1970s. This is a result of increased horizontal drilling activity and the introduction of multistage hydraulic fracturing completion technology. Total crude oil production from all wells in 2014 increased to 93.7 10^3 m^3/d from 92.5 10^3 m^3/d in 2013. Crude oil production increased even though the number of wells placed on production decreased between 2013 and 2014 because of the successful application of horizontal drilling, including multistage fracturing completion technology where wells produce at much higher productivities relative to vertical wells.

4.2.1.1 Drilling Activity

Figure S4.1 shows new conventional crude oil wells placed on production in 2013 and 2014 by Petroleum Services Association of Canada (PSAC) area. The number of crude oil wells placed on production in a given year generally tends to follow well drilling activity, as most wells are put on production shortly after being drilled. Drilling activity generally follows a seasonal cycle. Rig utilization is highest in the first quarter, as are the number of rig operating days. It falls in the second quarter because of reduced activity from spring breakup. In the third quarter, activity picks up again and continues on into the fourth quarter as cold weather opens access to more areas. In 2014, the number of crude oil wells placed on production decreased, from 2767 in 2013 to 2577 in 2014 due to lower crude oil prices and horizontal wells having a longer average length. With the latter, companies can get the same amount of production without having to drill as many wells.

4.2.1.2 Production Characteristics

Historical crude oil production from all wells (crude oil, natural gas, and other wells) by PSAC area is illustrated in **Figure S4.2**. In 2014, almost all of the PSAC areas experienced increases in production when compared to 2013 levels. The only two areas that did not see an increase were PSAC Areas 5 and 7. Production in PSAC Areas 5 and 7 decreased by 7.5 and 1.7 per cent, respectively, while PSAC Areas 1 and 2 had the highest increases at 9.5 and 12.5 per cent, respectively.

[1] Drain well: In a multileg well where more than one leg is open to the same pool, legs other than the main production contributor are called drain wells.

Table S4.1 Crude oil production and wells placed on production change highlights (10^3 m^3/d)

	2014	2013	Change	Change (%)[a]
Annual production				
Light	51.6	49.7	+1.9	+3.9
Medium	18.5	18.5	+0.03	+0.2
Heavy	6.5	7.10	−0.6	−8.5
Ultra heavy	17.0	17.2	−0.2	−0.7
Total	**93.7**[b]	**92.5**	**+1.2**[b]	**+1.3**
Number of oil wells placed on production in the year				
Vertical	359	481	−122	−25.4
Horizontal				
HMSF[c]	1 626	1 703	−77	−4.5
Other	592	583	+9	+1.5
Total	**2 577**	**2 767**	**−190**	**−6.9**

[a] Per cent changes are based on annual production volumes.

[b] Any discrepancies are due to rounding.

[c] Horizontal wells reported as being completed with hydraulic multistage fracturing (HMSF) technology.

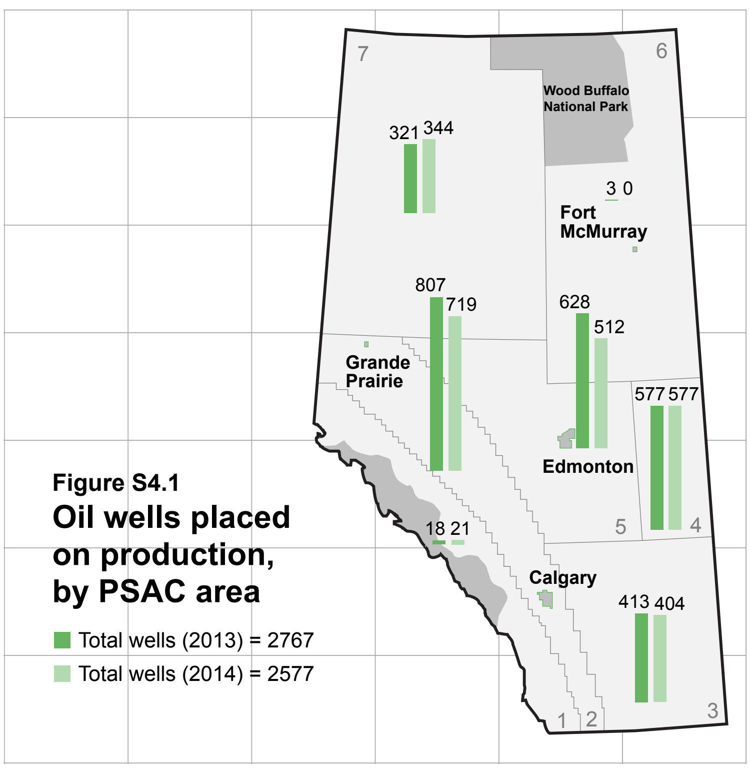


Figure S4.1
Oil wells placed on production, by PSAC area

Figure S4.3 shows the total average daily production rate from all wells and the total number of producing crude oil wells. The number of conventional crude oil wells producing oil has increased over time, from 8949 in 1970 to 41 601 in 2014. The well count of 41 601 conventional crude oil producing wells in 2014 does not include about 2413 wells classified as gas and 148 other wells that were producing crude oil. These gas and other wells accounted for less than 1 per cent of total production.

Of the 41 601 crude oil producing wells, about 35.4 per cent, or 14 742, are horizontal crude oil wells. Because of the higher average production rate per well, these horizontal wells contributed almost 59 per cent to the total crude oil production—an increase from 53 per cent in 2013 and 47 per cent in 2012. Of the 14 742 horizontal crude oil wells, about 17.7 per cent used multistage fracturing completion methods.

Figure S4.4 depicts producing crude oil wells and the average daily production rates of those wells by PSAC area in 2014. The average well productivity of producing crude oil wells in 2014 was 2.2 m^3/d, unchanged from 2013 but higher than in 2012. **Figure S4.5** shows the distribution of crude oil wells based on their average production rates in 2014. It shows that only 3.7 per cent of producing wells, from a total of 41 601, produced greater than 10 m^3/d. Roughly 48.3 per cent of producing crude oil wells produce at rates less than 1 m^3/d per well, consistent with basin maturity. In 2014, the 20 113 crude oil wells in this category produced at an average rate of 0.47 m^3/d and accounted for only 10.2 per cent of the total crude oil produced.

Conventional crude oil production from existing crude oil wells placed on production from 2005 to 2014 is depicted in **Figure S4.6**. This figure illustrates that crude oil wells placed on production in the last five years represented 58 per cent of crude oil production in 2014, up from 53 per cent in 2013 and 48 per cent in 2012 as a result of overall higher productivity of the newer wells.

Figure S4.7 compares historical Alberta conventional crude oil production from all wells (crude oil, natural gas, and other wells), with crude oil production from Texas onshore and North Dakota. Since around 2008, production has been rising rapidly in North Dakota. In 2014, production levels there were about nine times 2007 production levels due to the successful application of horizontal multistage fracturing technology. North Dakota's monthly oil production surpassed Alberta's conventional oil production in late 2011. By 2014, it was nearly 84.4 per cent higher than production in Alberta in 2014. Since 2010, Texas onshore and Alberta production have also reversed the downward production trend, demonstrating the remarkable growth in Texas and modest growth in Alberta in 2014.

Starting with this year's report, the AER has revised its method of calculating initial productivity rates. In the past, the AER has used the first full calendar year of production to calculate initial productivity. The AER now uses the first 12 months of production for the well. These normalized initial productivities have been calculated for the average of the latest three years and the average of the last five years, with the three-year average presented in this report in **Figure S4.8**.

Figure S4.8 shows the three-year average initial well productivity by well type per PSAC area for conventional crude oil wells placed on production in 2014. As shown in the chart, average initial productivity of new producing conventional crude oil wells varies throughout the province and differs between vertical and horizontal

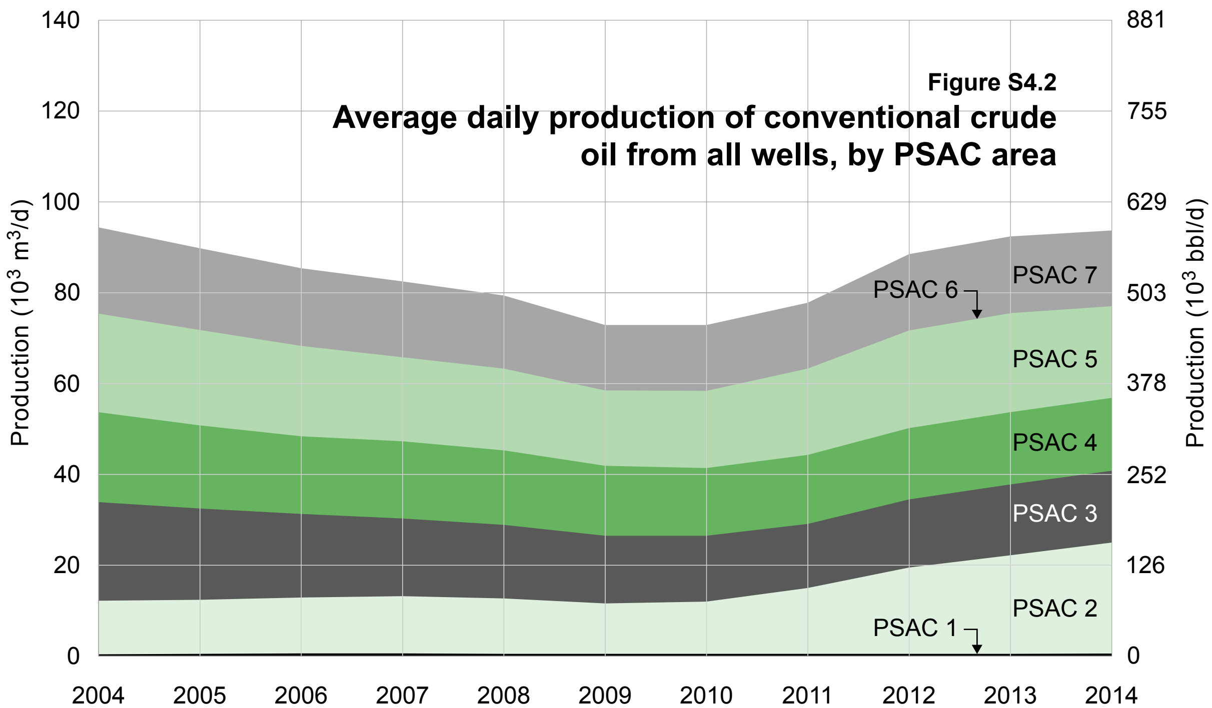


Figure S4.2
Average daily production of conventional crude oil from all wells, by PSAC area
Production (10^3 m^3/d)
Production (10^3 bbl/d)
PSAC 1
PSAC 2
PSAC 3
PSAC 4
PSAC 5
PSAC 6
PSAC 7
0
20
40
60
80
100
120
140
0
126
252
378
503
629
755
881
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014

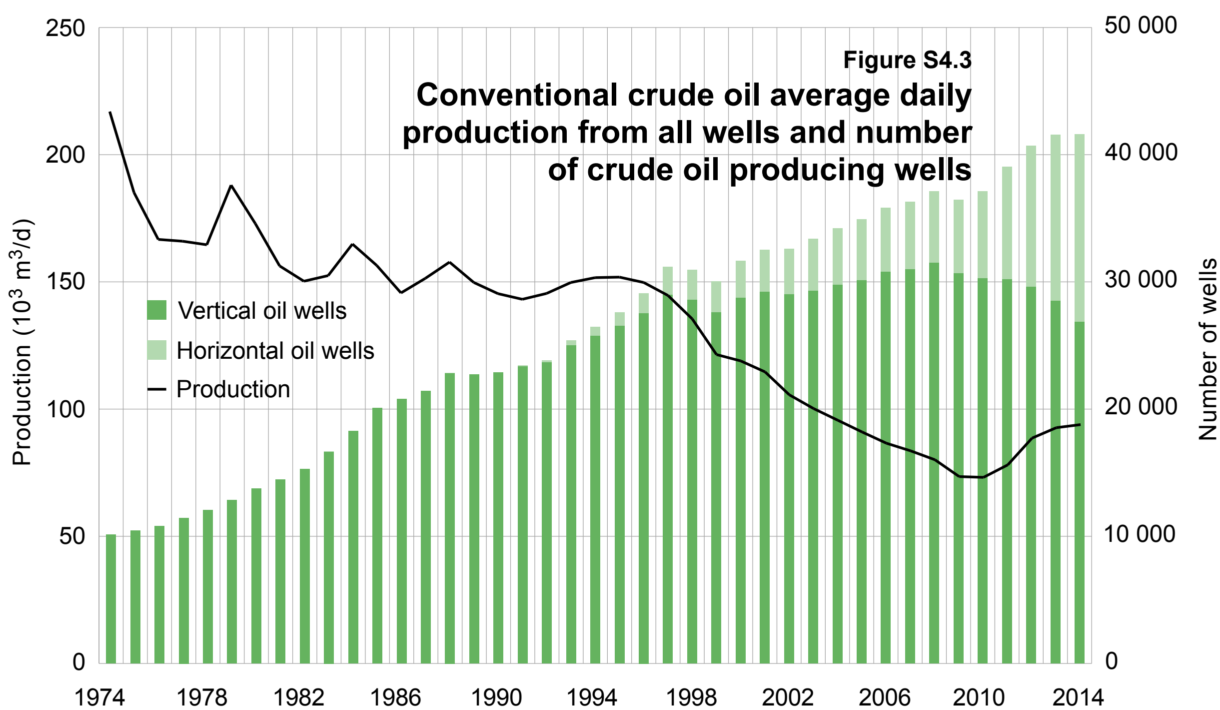


Figure S4.3
Conventional crude oil average daily production from all wells and number of crude oil producing wells
Production (10^3 m^3/d)
Number of wells
Vertical oil wells
Horizontal oil wells
Production
0
50
100
150
200
250
0
10 000
20 000
30 000
40 000
50 000
1974
1978
1982
1986
1990
1994
1998
2002
2006
2010
2014

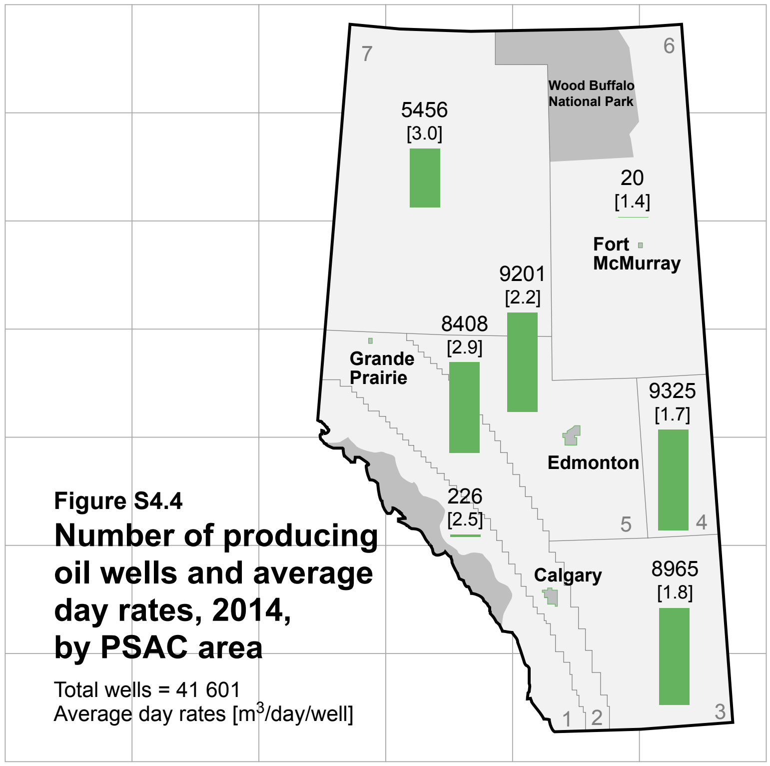


Figure S4.4
Number of producing oil wells and average day rates, 2014, by PSAC area

Total wells = 41 601
Average day rates [m³/day/well]

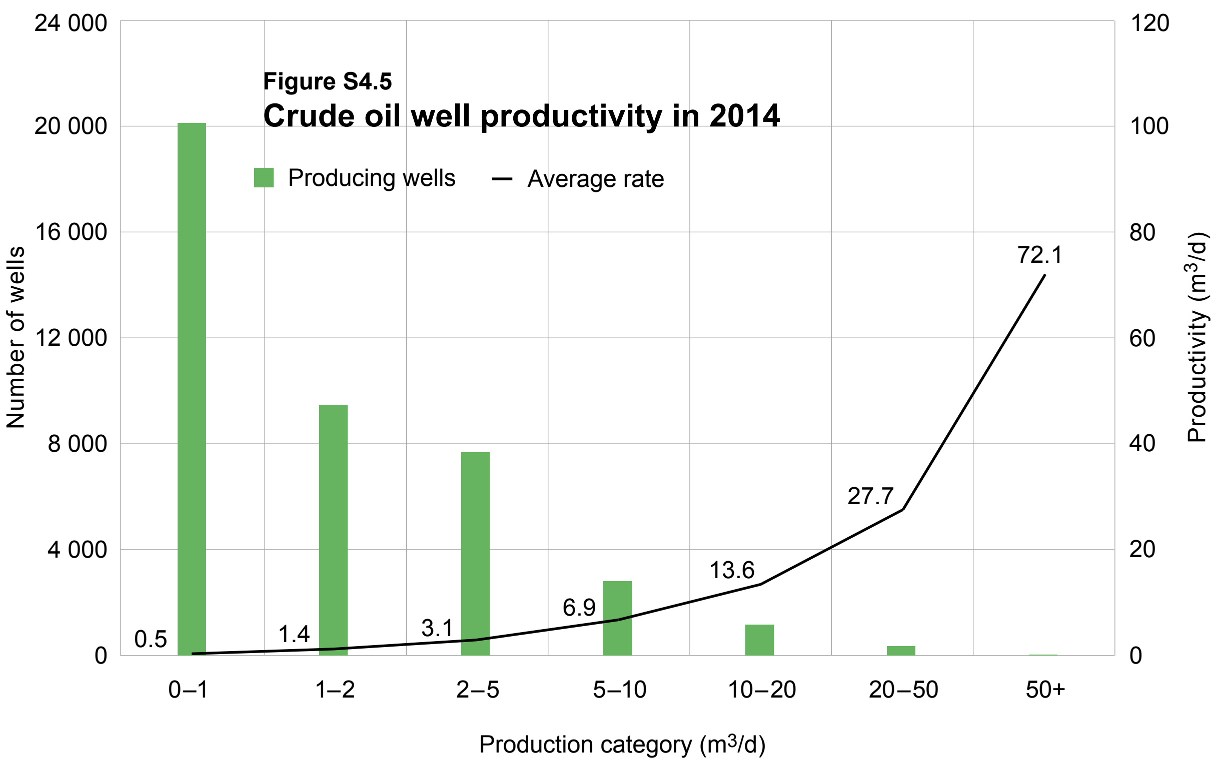


Figure S4.5
Crude oil well productivity in 2014

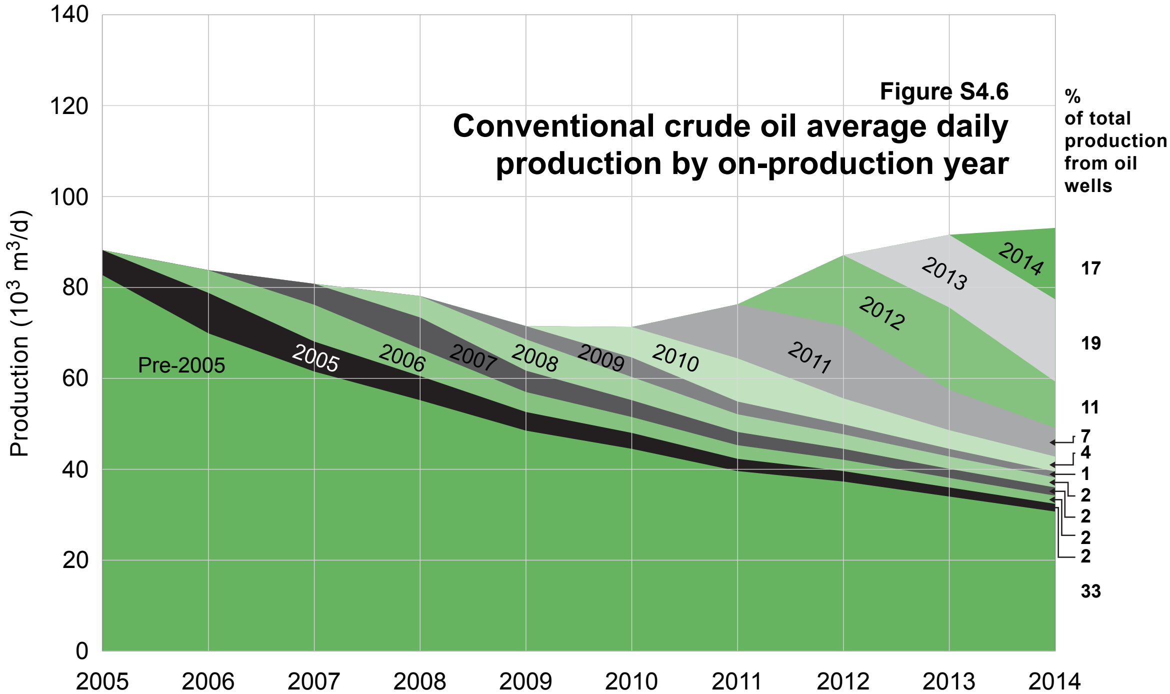


Figure S4.6
Conventional crude oil average daily production by on-production year
% of total production from oil wells
Production (10³ m³/d)
140
120
100
80
60
40
20
0
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
Pre-2005
17
19
11
7
4
1
2
2
2
2
33

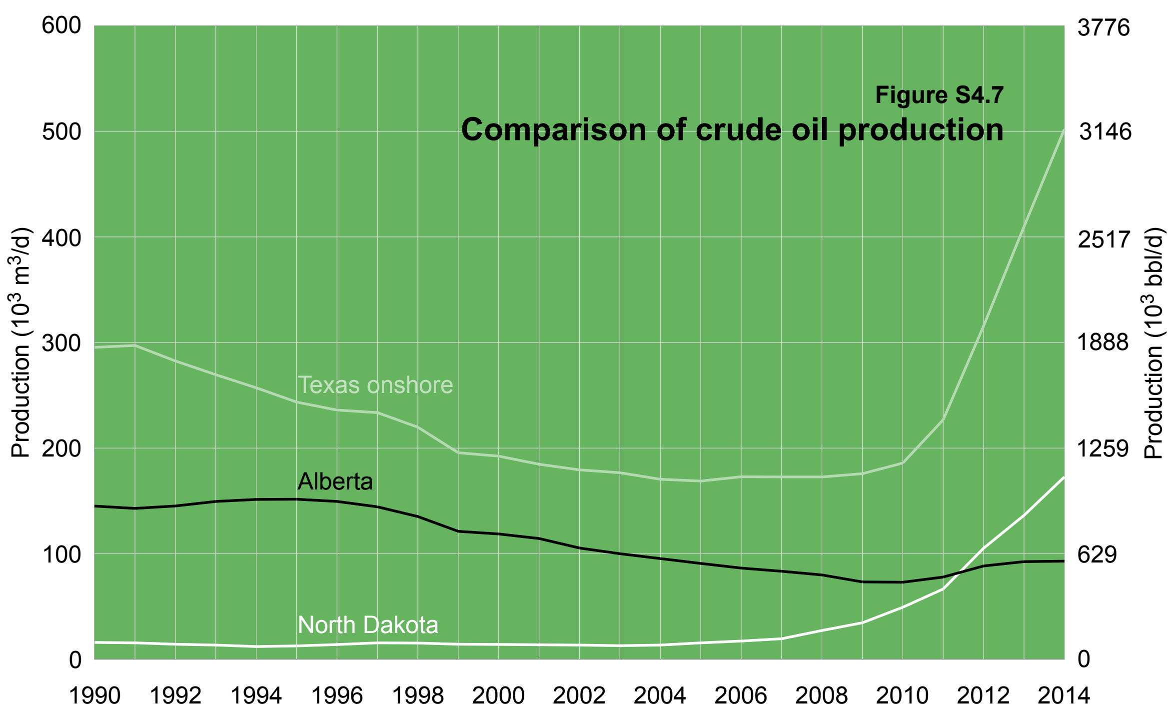


Figure S4.7
Comparison of crude oil production
Production (10³ m³/d)
Production (10³ bbl/d)
600
500
400
300
200
100
0
3776
3146
2517
1888
1259
629
0
Texas onshore
Alberta
North Dakota
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014

well types. PSAC Areas 5 and 7 had the highest initial production for vertical crude oil producing wells. PSAC Areas 2 and 7 had the highest initial production for horizontal crude oil producing wells. On average, horizontal wells have higher initial productivity rates than vertical wells, especially if completed using multistage fracturing technology. Due to limited information, no initial productivities could be calculated for vertical wells in PSAC Area 1 and for all of PSAC Area 6.

4.2.2 Supply Costs

Table S4.2 summarizes the estimated costs for conventional crude oil from selected areas in Alberta based on 2014 estimated costs and representative production profiles. The supply costs are based on representative wells in each PSAC area. Supply costs for different geological plays and PSAC areas vary significantly because of differing production rates, well types, drilling and operating costs, royalties, and other factors. Therefore, the results may not reflect wells that differ from the representative well profiles used in the analysis.

The supply cost estimate for an average horizontal or vertical well in each PSAC area includes the following data: formation, initial productivities, production decline rates, vertical drilled and total measured depths of the wells, gas composition, shrinkage, capital cost, operating costs, royalties, taxes, and a 10 per cent nominal rate of return. The supply costs are not risked (i.e., assumes a 100 per cent success rate). Supply costs are estimated as plant-gate costs, which are reported in Canadian dollars (Cdn$).

Table S4.2 shows that wells with higher initial productivities and longer total measured depths typically have lower supply costs, as the higher initial productivities of these wells offset the generally higher capital costs

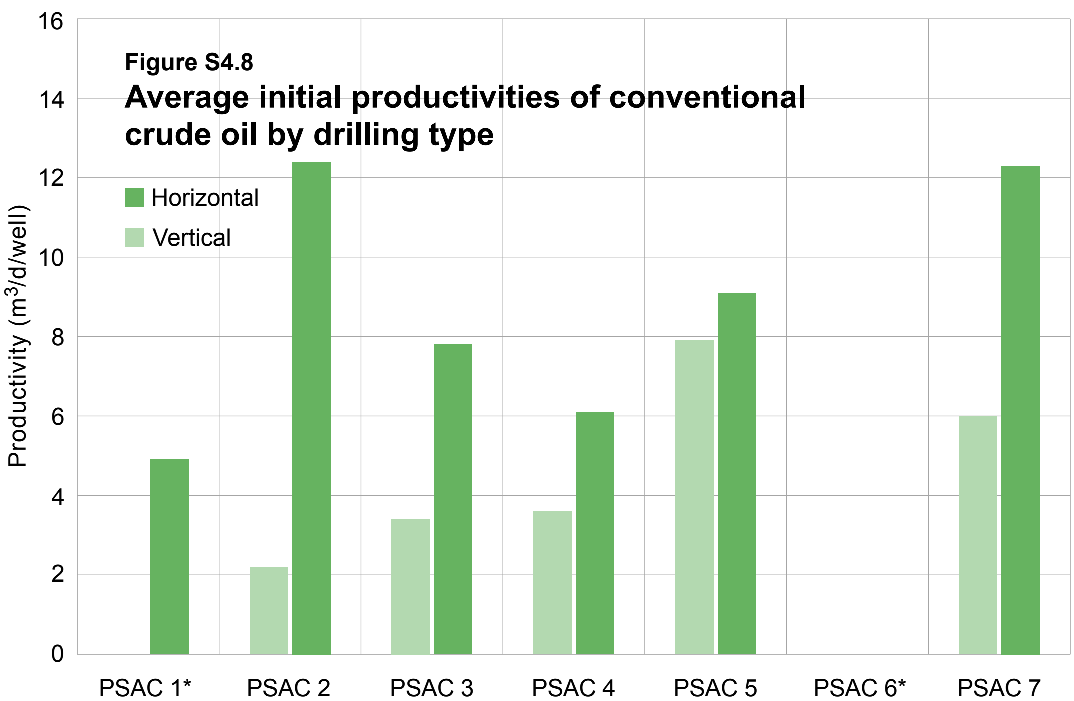


Figure S4.8
Average initial productivities of conventional crude oil by drilling type

* Limited data available.

Table S4.2 Crude oil supply costs for PSAC areas[a]

Area	Formation	Type of well	Type of oil	Total measured depth (m)	Initial productivity (m^3/d)	Total capital cost (Cdn$000)	Variable operating cost (Cdn$/$m^3$)	Crude oil supply cost (Cdn$/)
PSAC 2	Cardium	Horizontal	Sweet light	3 200	12.5	3 317	42.79	59.87
PSAC 2	Cardium	Horizontal	Sweet medium	3 600	11.9	3 541	49.08	76.30
PSAC 2	Spirit River	Horizontal	Sweet light	4 230	12.5	6 627	42.79	123.14
PSAC 3	Nisku	Directional	Sour light	2 000	3.3	1 983	57.58	108.01
PSAC 3	Sunburst	Vertical	Sweet medium	1 540	3.3	1 089	77.09	62.73
PSAC 3	Banff	Horizontal	Sour medium	3 800	10.0	5 220	80.86	123.73
PSAC 4	Sparky SS	Horizontal	Sweet heavy	1 600	6.8	1 007	59.78	41.60
PSAC 5	Rock Creek	Horizontal	Sweet medium	2 300	3.7	2 243	39.96	140.70
PSAC 5	Cardium	Horizontal	Sweet light	2 600	13.4	2 970	42.79	67.64
PSAC 7	Gilwood	Vertical	Sweet light	1 770	5.5	1 716	73.63	68.30
PSAC 7	Keg River	Horizontal	Sweet light	2 050	13.8	3 165	22.03	64.78
PSAC 7	Beaverhill Lake	Directional	Sweet light	2 500	5.5	2 437	73.63	92.52
PSAC 7	Montney	Horizontal	Sweet light	4 000	13.8	5 561	83.70	101.72

[a] Cost data from petroCUBE, and PSAC's *2015 Well Cost Study* (published in October 2014) has been used to estimate the supply costs in PSAC areas.

associated with drilling deeper and longer wells. Higher capital costs are associated with these wells, notably those in PSAC Areas 2, 3, and 7. Similarly, vertical and directional wells with lower initial productions tend to have higher supply costs relative to horizontal wells in the same PSAC area, despite lower capital costs. Each of the representative wells are assumed to have only one lateral, which likely creates an upwards bias on supply cost estimates. Multiwell pads and multilateral wells would incur marginal capital costs for additional legs, while gained production efficiencies would reduce average supply costs relative to unilateral wells.

With Alberta crude oil wellhead prices averaging $89.40/bbl for light-medium and $75.29/bbl for heavy in 2014, the previous year proved to be economical for a majority of the representative wells included in **Table S4.2**. Though the table reports supply costs for 2014, the recent low price environment is likely to influence drilling decisions and improve cost efficiencies moving forward. As supply costs adapt in the future, operators will be able to sustain production economically for certain wells.

The advent of horizontal drilling using multistage fracturing completion methods continues to enhance the development of crude oil in Alberta. The supply cost results representing the horizontal wells in PSAC Areas 2 and 5 in 2014 are consistent with industry trends pursuing extraction in the Cardium Formation, which underlies the two areas. Aggregate well activity has also remained significant in PSAC Areas 3 and 4, albeit less than in PSAC Areas 2 and 5. Although the shallower plays of the southeastern PSAC areas suggest more favourable economics for producers, lower initial output coupled with sour and heavy oil production increases average supply costs.

4.2.3 Crude Oil Production – Forecast

In projecting conventional crude oil production over the forecast period, the AER has separated production coming from vertical wells and horizontal wells. The forecast for production from new vertical wells acknowledges industry's continued interest in drilling for crude oil using conventional technology. The horizontal category of wells includes traditional wells and wells completed using multistage fracturing technology.

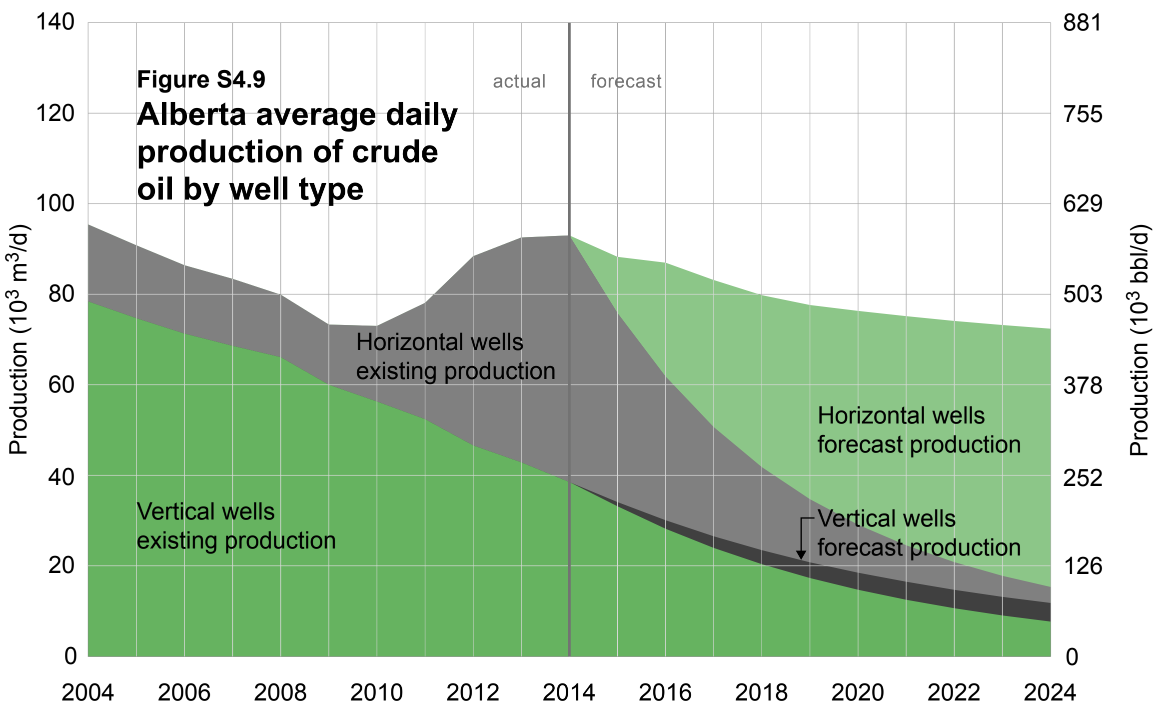
To forecast production from each category, production from existing wells and new wells placed on production each year has been analyzed. The number of producing wells, their decline rates, and the average productivity of the wells in each category are the main factors used to project crude oil production over the forecast period.

Figure S4.9 illustrates the projected conventional crude oil production from all vertical and horizontal wells. Potential crude oil production from existing and new wells is combined to project total production over the forecast period.

4.2.3.1 Vertical and Horizontal Wells

To forecast conventional crude oil production from vertical and horizontal wells, the AER assumes the following:

- That the number of new vertical and horizontal crude oil wells placed on production will decrease between 2014 and 2015 and then steadily increase from 2016 onwards until the end of the forecast period. The decline in 2015 corresponds to the supply cost information and lower crude oil prices. The recovery after 2015 reflects industry's continued focus on horizontal drilling and the expected recovery of conventional crude oil prices by

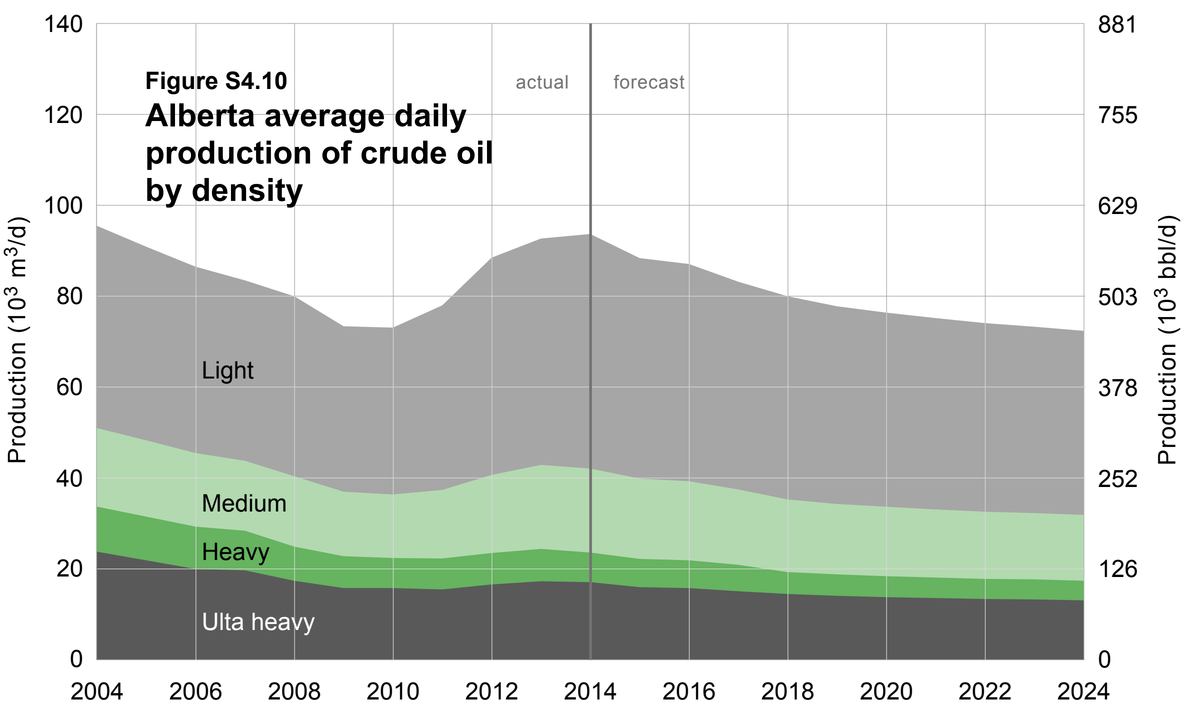


the end of the forecast. The higher well forecast after 2015 also reflects lower costs and improved efficiencies achieved by producers.

- The number of new vertical crude oil wells over the forecast period will decrease from 359 in 2014 to 252 in 2015 and then steadily increase to 276 wells by 2024. The number of new horizontal crude oil wells placed on production will decrease from 2218 in 2014 to 1548 in 2015. This number is then expected to increase to 2024 in 2022 and remain at that level for the rest of the forecast period. The overall lower forecast relative to last year is a result of the low production forecast for 2015, and the assumption regarding the increase in producing wells for the remainder of the forecast.

- The percentage of new conventional horizontal crude oil wells placed on production is assumed to increase over the forecast period from about 86 per cent in 2014 to about 88 per cent by 2024. This increase is supported by historical data where about 72 per cent of wells placed on production in 2011 were horizontal compared to 83 per cent in 2013. Horizontal wells have significantly higher productivity at lower marginal cost when compared to vertical wells; therefore, the forecast assumes horizontal wells will remain the focus of drilling for crude oil producers.

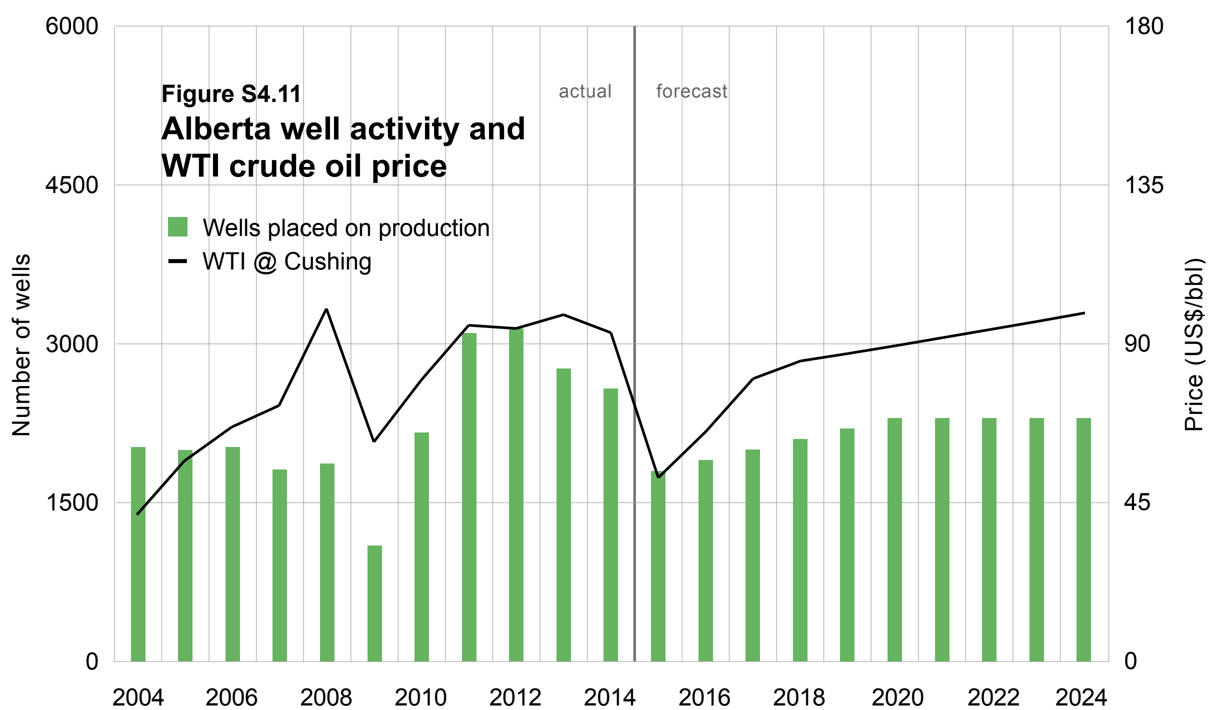
- The AER has forecast initial productivity for those wells expected to be placed on production within the forecast period by year and well type. A higher proportion of new wells are being drilled into better geological targets, resulting in higher initial production followed by steep declines. By 2024, many of the better geological targets are expected to have been depleted, resulting in declining average initial production for new wells over the forecast period.



- The average initial production rate for new vertical crude oil wells is assumed to be 3.7 m^3/d per well in 2015 and is expected to decline to 2.8 m^3/d by the end of the forecast. The rate for new conventional horizontal crude oil wells is expected to be 8.0 m^3/d per well in 2015 and to decline to 6.1 m^3/d per well by the end of the forecast period. These average initial production rates are higher than those used in last year's forecast.
- Production from existing vertical and horizontal wells will decline by 15 per cent and 24 per cent, respectively, per year.
- The AER also predicts decline rates for those wells expected to be placed on production within the forecast period by year and well type. Production from new conventional vertical crude oil wells will decline by 31 per cent the first year, 25 per cent the second year, 21 per cent the third year, and 18 per cent over the remaining years. Production from new conventional horizontal crude oil wells will decline by 45 per cent the first year, 28 per cent the second year, 17 per cent the third year, 15 per cent the fourth year, and 9 per cent over the remaining years. These decline rates are both higher and decline at a faster rate than those made in previous years. This is due to higher depletion rates in new pools than previously estimated.

4.2.3.2 Production

The projected total crude oil production from all wells, which comprises production from both existing wells and new vertical and horizontal wells, is illustrated in **Figure S4.9**. Based on actual and projected industry activity levels, the production forecast for 2015 is 88.3 10^3 m^3/d, which is slightly lower compared to the forecast last year for 2015 of 91.1 10^3 m^3/d, a decline of about 5 per cent. This decline is a result of the drop in oil prices in the

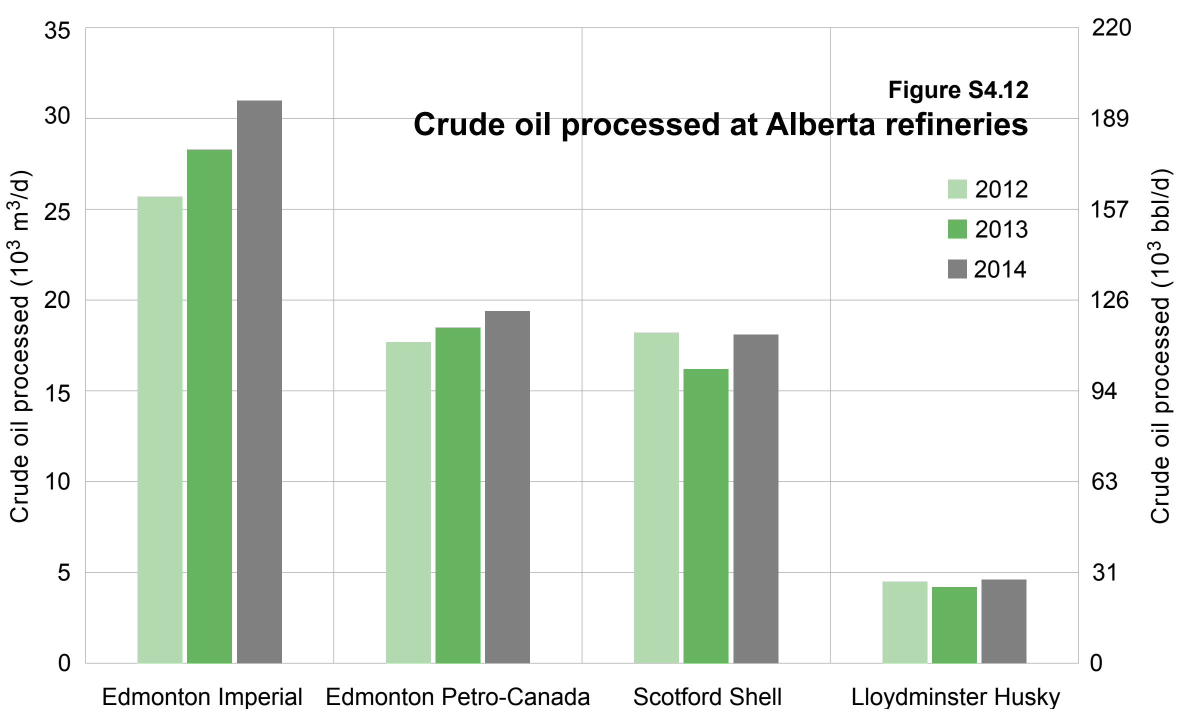


latter half of 2014 and a lower projected price for 2015, an anticipated decrease in the number of wells placed on production in 2015, and higher decline rates for both existing wells and new wells.

Conventional crude oil production is expected to slightly decline over the remainder of the forecast period, although increasing levels of drilling activity are expected over time, higher decline rates and lower average initial production rates predicted for new horizontal wells will not overcome overall production decline rates for vertical wells. These lower average initial production rates and higher decline rates indicate a mature basin. The combined forecasts for existing and future wells indicate that total crude oil production will be 88.3 10^3 m^3/d in 2015 and 87.0 10^3 m^3/d in 2016, before gradually decreasing to 72.4 10^3 m^3/d in 2024.

Figure S4.10 shows the crude oil production forecast split between ultra-heavy, heavy, medium, and light crude oil from all wells (crude oil, natural gas, and other wells). Crude oil production for all densities is expected to decrease, starting in 2015 and continuing on to 2024. Conventional heavy crude oil production will see the greatest decline (29.5 per cent) whereas conventional light crude oil will see the lowest decline (16.3 per cent).

Figure S4.11 illustrates the annual number of new conventional crude oil wells expected to be placed on production from 2015 to 2024 and includes the forecast for West Texas Intermediate (WTI) crude oil price. The lower crude oil price forecast supports the projected moderate oil drilling activity, with an estimated total of 2300 producing wells by the end of the forecast period. Over the longer term, investment dollars are expected to be more evenly distributed between gas (with associated natural gas liquids) and crude oil drilling to maximize profits.



4.2.4 Crude Oil Demand

Oil refineries use mainly crude oil, butanes, and natural gas as feedstock, along with upgraded and nonupgraded bitumen and pentanes plus, to produce a wide variety of refined petroleum products (RPPs). The key determinants of crude oil feedstock requirements for Alberta's refineries are domestic Albertan demand for RPPs, shipments to other western Canadian provinces, and exports to the United States.

In 2014, Alberta's operating refineries, with a total annual throughput of 73.0 10^3 m^3/d of crude oil and equivalent, processed 19.4 10^3 m^3/d of conventional crude oil. This is a 10.9 per cent increase in crude oil processed over 2013.

Both upgraded and nonupgraded bitumen, together with pentanes plus, constitute the remaining feedstock processed through Alberta's refineries. **Figure S4.12** illustrates the current capacity and location of refineries in Alberta. Additions to crude oil refining capacity are not expected over the forecast period.

In 2014, refinery utilization increased compared to 2013 and 2012, as crude oil processed increased without an increase in stated capacity. Refineries can process more crude oil than their stated capacity from debottlenecking and other efficiencies. Shell Scotford had the highest increase in crude oil processed at 11.8 per cent between 2013 and 2014.

Shipments of crude oil outside of Alberta, shown in **Figure S4.13**, amounted to 79.3 per cent of total production in 2014. The AER expects that by 2024, this figure will slowly decrease to about 76.0 per cent of production due to the decline expected in Alberta light, medium, heavy, and ultra-heavy crude oil production in 2024.

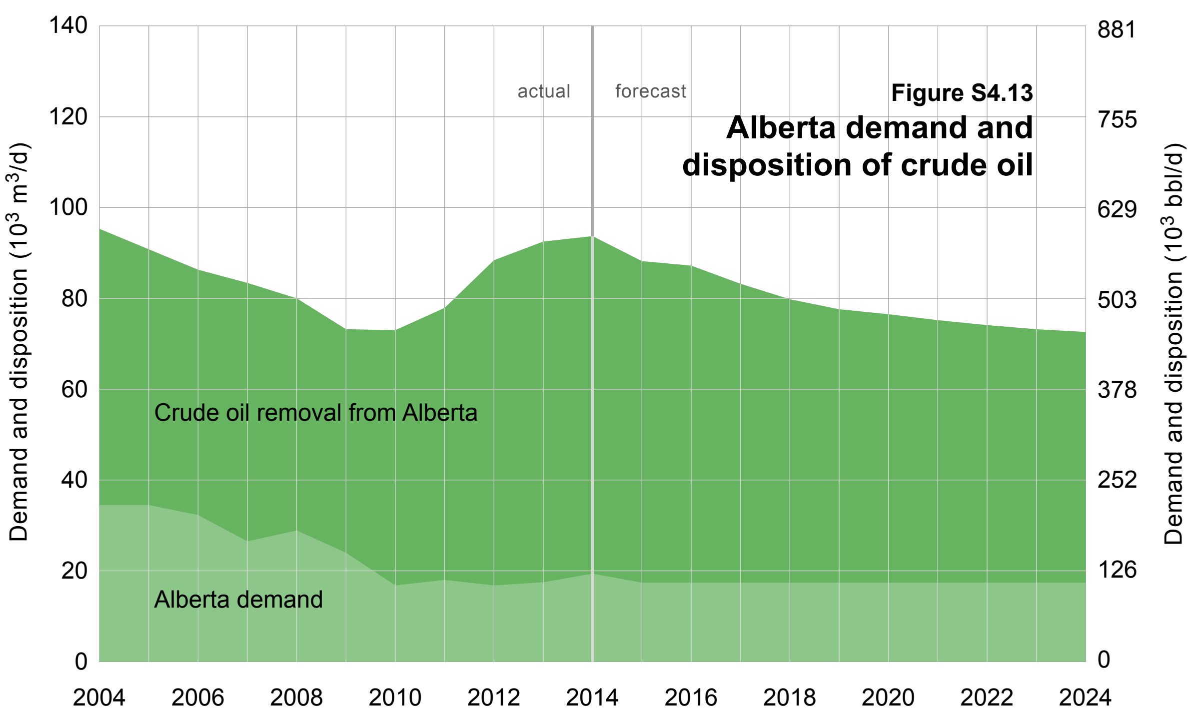


Figure S4.13
Alberta demand and disposition of crude oil

HIGHLIGHTS

Alberta's remaining established conventional natural gas reserves decreased by 4 per cent in 2014 to 865 billion cubic metres.

Additions to reserves due to new drilling replaced 30 per cent of conventional gas production.

Marketable gas production increased by 2 per cent in 2014, the first year-over-year increase since 2006.

Conventional and shale gas wells placed on production increased by 43 per cent and 24 per cent, respectively, while coalbed methane wells placed on production fell by 34 per cent.

5 NATURAL GAS

Raw natural gas consists mostly of methane and other hydrocarbon gases, but it also contains nonhydrocarbons, such as nitrogen, carbon dioxide, and hydrogen sulphide (H_2S). These impurities typically make up less than 10 per cent of raw natural gas. The estimated average composition of the hydrocarbon component without impurities is about 92 per cent methane, 5 per cent ethane, and lesser amounts of propane, butanes, and pentanes plus.

The range of hydrocarbon gas components in Alberta's natural gas covers a wide spectrum, from dry gas to liquids-rich gas. Dry gas generally consists of mostly methane with some examples being shallow gas pools located in southeast Alberta and coalbed methane (CBM) deposits in central Alberta. Gas with small amounts of extractable liquids is referred to as lean gas, whereas gas with larger amounts is called wet gas. Liquids-rich gas refers to natural gas that contains an unusually high amount of liquids. Pools containing liquids-rich gas are often found along the front of the foothills of the province.

Hydrocarbon components that exist in gaseous form in the reservoir but which condense and are recovered as a liquid at the surface may be reported as gas equivalent or condensate. Such liquids—including ethane, which is primarily produced as a gas—are referred to as natural gas liquids (NGLs) and are reported in **Section 6**. Marketable gas is the gas that remains after the raw gas is processed to remove nonhydrocarbons and heavier natural gas liquids and that meets specifications for use as a fuel. Marketable gas reserves are determined by applying a surface loss or shrinkage factor to the raw gas volume and are described in **Section 5.1.3.5**.

The AER refers to unconventional natural gas as "tight" gas, shale gas, and CBM. Tight gas refers to natural gas found in low-permeability rock, including sandstone, siltstone, and carbonates. Shale gas is natural gas found locked in fine-grained, organic-rich rock. CBM is natural gas contained in coal. This section discusses conventional natural gas as well as CBM and shale gas. The AER, however, does not separately estimate or report tight gas reserves or production for historical, regulatory, and administrative reasons. It is often difficult or impossible to separate the tight portion of the reserves or production of a conventional reservoir. Therefore, any unconventional tight gas volumes are included within the AER's conventional natural gas reserves and production reporting.

In this section, natural gas volumes are referred to as either the actual metered volume with the combined heating value of the hydrocarbon components present in the gas (i.e., "as is") or the volume at standard conditions of 37.4 megajoules per cubic metre (MJ/m^3). The average heat content of produced conventional natural gas leaving field plants is estimated to be 39.2 MJ/m^3. This compares with a heat content of about 37.0 MJ/m^3 for CBM.

5.1 Reserves of Natural Gas

5.1.1 Provincial Summary

As of December 31, 2014, the AER estimates the remaining established reserves of marketable conventional gas in Alberta downstream of field plants to be 865 billion (10^9) m^3, with a total energy content of about 34 exajoules (10^{18} joules). This decrease of 32.2 10^9 m^3 since December 31, 2013, is a result of all reserves additions less production during 2014. These reserves include 28.7 10^9 m^3 of ethane and other NGLs, which are present in marketable gas leaving the field plant and are subsequently recovered at straddle plants. Removal of NGLs results in a 4.6 per cent reduction in the average heating value, from 39.2 MJ/m^3 to 37.4 MJ/m^3, for gas downstream of straddle plants. Details of the changes in marketable reserves during 2014 are shown in **Table R5.1**. Total provincial initial gas in-place and raw producible gas reserves for 2014 were 9504.0 and 6344.3 10^9 m^3, respectively, which translates into an average provincial recovery factor of 67 per cent. Total initial established marketable reserves were estimated to be 5486.8 10^9 m^3, representing an average surface loss of 14 per cent.

Annual historical reserves additions and natural gas production are depicted in **Figure R5.1**. It shows that reserves additions have generally not kept pace with production. As illustrated in **Figure R5.2**, Alberta's remaining established reserves of marketable conventional gas have decreased by about 52 per cent since 1984.

Table R5.1 Reserve and production changes in marketable conventional gas (10^9 m^3)

	Gross heating value (MJ/m^3)	Volumes		
		2014	2013	Change
Initial established reserves		5 486.8	5 420.6	+66.3
Cumulative production		4 621.5	4 523.0	+98.5[a]
Remaining established reserves downstream of field plants				
As is	39.2	865.3	897.5	−32.2
		(30.7 Tcf)[b]	(31.9 Tcf)[b]	
Minus liquids removed at straddle plants		28.7	29.6	−0.9[c]
Remaining established reserves downstream of straddle plants				
As is	37.4	836.6[c]	867.9[c]	−31.3[c]
		(29.7 Tcf)[b]	(30.8 Tcf)[b]	
Annual production	37.4	96.8[d]	94.4[d]	+2.3[d]

[a] Change in cumulative production is a combination of annual production and all adjustments to previous production records.

[b] Tcf = trillion cubic feet.

[c] Any discrepancies are due to rounding.

[d] Does not include conventional gas from AER-defined unconventional wells.

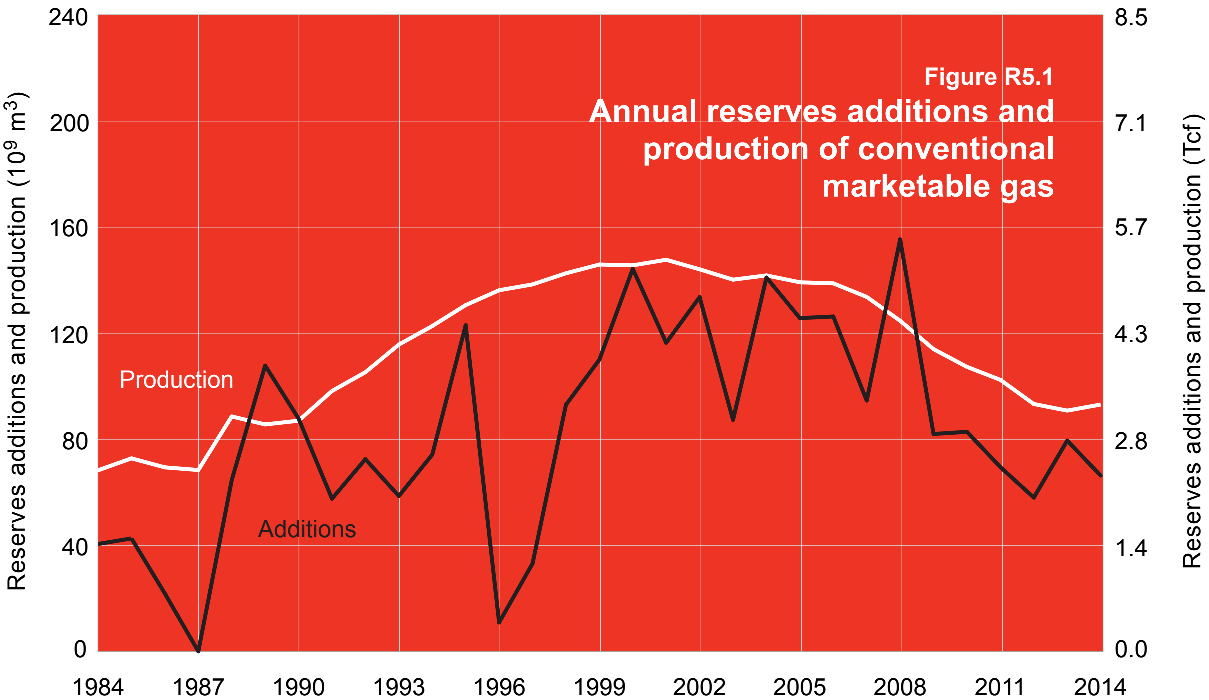


Figure R5.1
Annual reserves additions and production of conventional marketable gas
Reserves additions and production (10^9 m^3)
Reserves additions and production (Tcf)
Production
Additions
240
200
160
120
80
40
0
8.5
7.1
5.7
4.3
2.8
1.4
0.0
1984
1987
1990
1993
1996
1999
2002
2005
2008
2011
2014

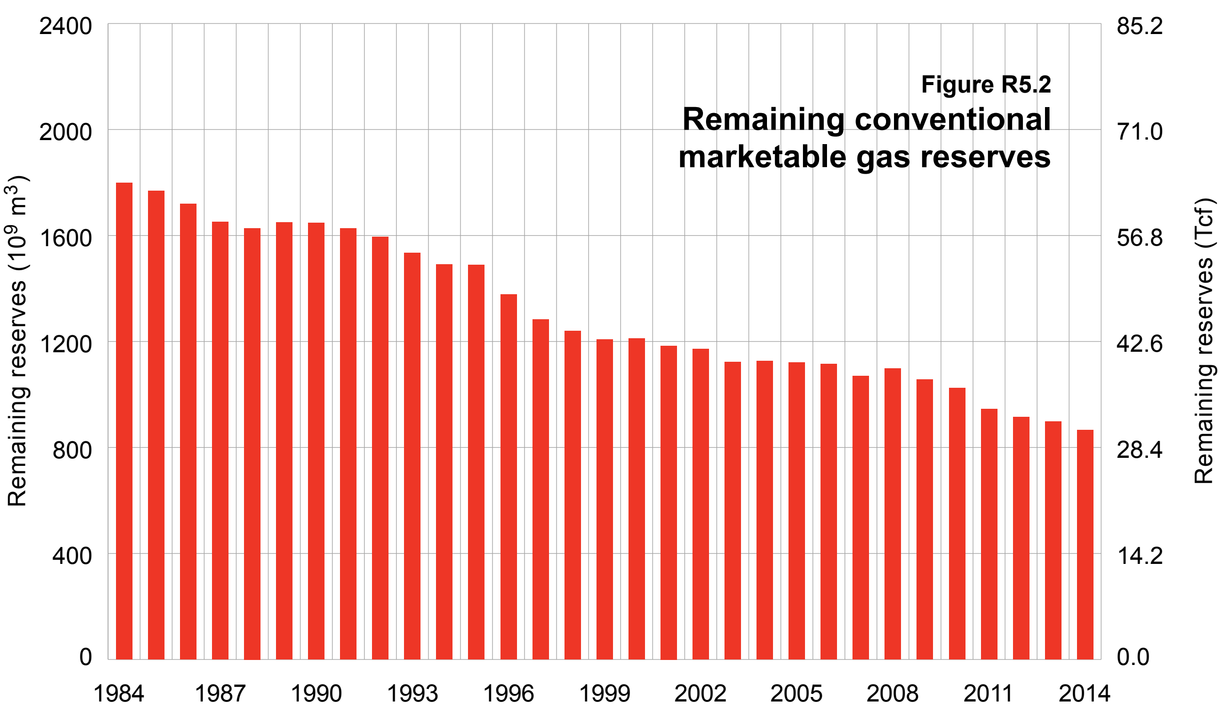


Figure R5.2
Remaining conventional marketable gas reserves
Remaining reserves (10^9 m^3)
Remaining reserves (Tcf)
2400
2000
1600
1200
800
400
0
85.2
71.0
56.8
42.6
28.4
14.2
0.0
1984
1987
1990
1993
1996
1999
2002
2005
2008
2011
2014

The AER estimates the initial established reserves of CBM to be 103.1 10^9 m^3 as of December 31, 2014, relatively unchanged from 2013. Remaining established reserves in 2014 were 47.8 10^9 m^3, down from 51.5 10^9 m^3 in 2013 due to production.

A summary of CBM reserves and production is shown in **Table R5.2**. In 2014, the annual production from all wells listed as CBM was 7.0 10^9 m^3. This volume represents the total contribution from CBM wells, including wells commingled with conventional gas (known as CBM hybrid wells). The portion of production estimated to be attributed to only CBM is 4.7 10^9 m^3.

5.1.2 In-Place Resources

The AER estimates the initial in-place resources of conventional and CBM natural gas in Alberta to be 9805 10^9 m^3, consisting of 9504 10^9 m^3 of conventional natural gas and 301 10^9 m^3 of CBM. With a conventional cumulative raw production of 5383 10^9 m^3, 4121 10^9 m^3 remains in the ground. CBM cumulative raw production is 55 10^9 m^3 and 246 10^9 m^3 of CBM remains in the ground. As of December 31, 2014, 4367 10^9 m^3 of natural gas remains unproduced in Alberta. With current technologies, 1009 10^9 m^3 is still expected to be produced.

Additionally, the shale- and siltstone-hosted hydrocarbon resources study discussed in **Section 2.2.2** has identified 95 944 10^9 m^3 (3406 trillion cubic feet [Tcf]) of unconventional in-place shale gas resources in six key shale formations in Alberta. This very large resource represents a huge potential for future development; however, the technical, economic, environmental, and social constraints on recoverability were not studied in the report. Consequently, the AER has not determined any established reserves from this resource.

5.1.3 Established Reserves of Conventional Natural Gas

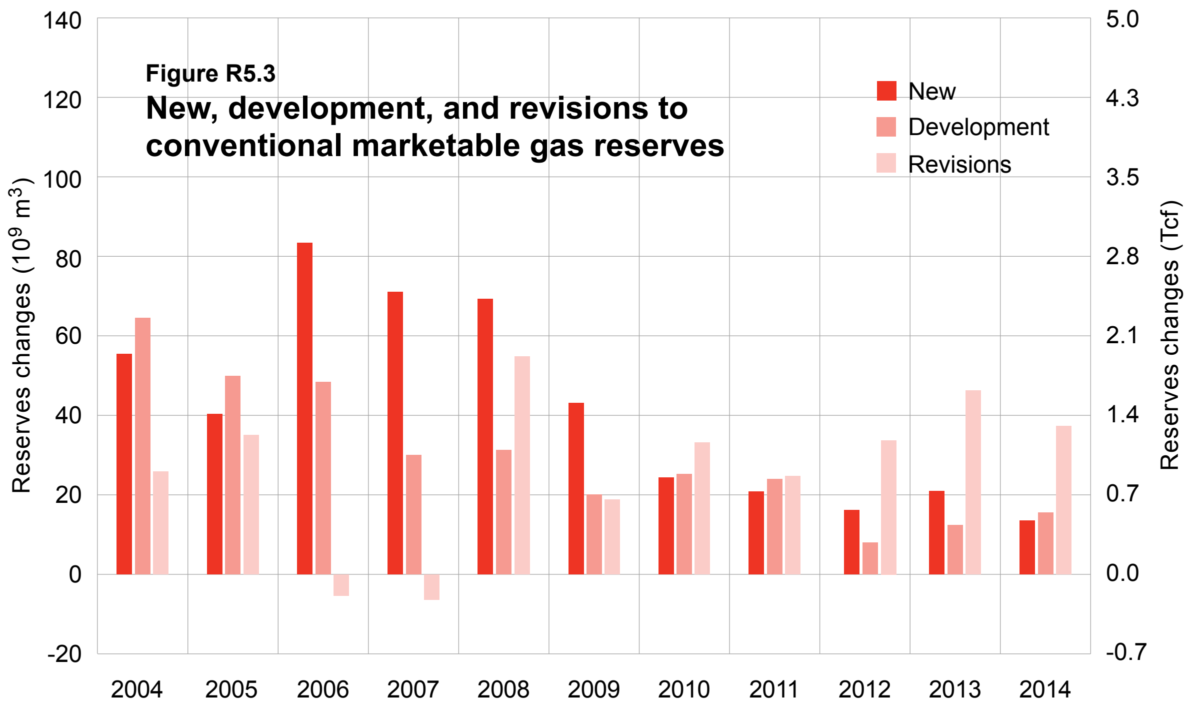
Figure R5.3 breaks down the historical annual reserves changes according to new pools, development of existing pools, and reassessment of reserves of existing pools. The 66.3 10^9 m^3 increase in initial reserves for 2014 includes the addition of 13.5 10^9 m^3 attributed to new pools booked in 2014, 15.5 10^9 m^3 from the development of existing pools, and a net reassessment of 37.3 10^9 m^3 for existing pools. Reserves added through drilling (new plus development) totalled 29.0 10^9 m^3, replacing 30 per cent of Alberta's 2014 production. This is down from

Table R5.2 CBM reserve and production change highlights (10^9 m^3)

	2014	2013	Change
Initial established reserves	103.1	101.7	+1.4
Cumulative production	55.3	50.2	+5.0[a]
Remaining established reserves	47.8	51.5	-3.7
	(1.7 Tcf)[b]	(1.8 Tcf)[b]	
Annual production	4.7	5.2	-0.5

[a] Change in cumulative production is a combination of annual production and all adjustments to previous production records.

[b] Tcf = trillion cubic feet.



36 per cent in 2013, but is still higher than in 2012, which at 25 per cent was the lowest replacement ratio in the last 15 years. Historical reserves growth and production data since 1966 are shown in **Appendix B**, **Table B.4**.

Figure R5.4 illustrates initial marketable gas reserves growth between 2013 and 2014 by areas defined by the Petroleum Services Association of Canada (PSAC). The most significant growth was in PSAC Area 2, which accounted for 41 per cent of the total annual increase for 2014. Among the pools in PSAC Area 2 that contributed to this increase in reserves were the Edson Upper Mannville II, Kakwa Montney D, Kakwa Montney E, Kakwa Montney L, and Wild River Commingled MFP 9529, for a total reserves increase of 9.5 10^9 m^3.

5.1.3.1 Distribution of Conventional Natural Gas Reserves by Pool Size

The distribution of marketable gas reserves by pool size is shown in **Table R5.3**. Commingled pools are considered as one pool, whereas each pool in a multifield pool is counted as a separate pool. The data show that pools with reserves of less than 30 million (10^6) m^3, while representing 75 per cent of all pools, contain only 11 per cent of the province's remaining marketable reserves. Similarly, pools with reserves greater than 3000 10^6 m^3, while representing only 0.5 per cent of all pools, contain 53 per cent of the remaining reserves.

5.1.3.2 Geological Distribution of Conventional Natural Gas Reserves

The distribution of reserves by geological period is shown in **Figure R5.5**. The Upper and Lower Cretaceous periods account for about 72 per cent of the province's remaining established reserves of marketable gas and are important as a future source of natural gas.

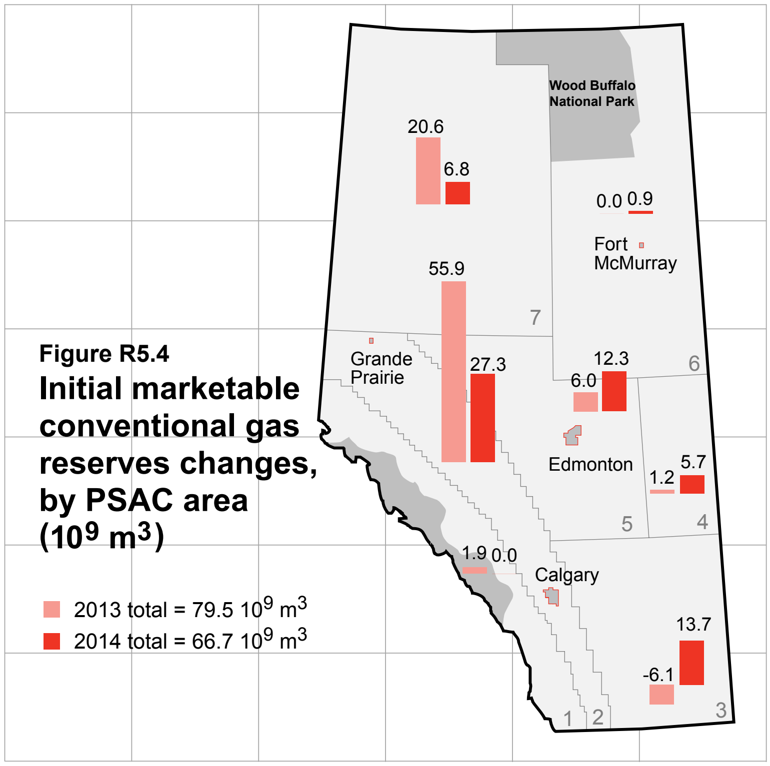


Figure R5.4
Initial marketable conventional gas reserves changes, by PSAC area (10^9 m^3)

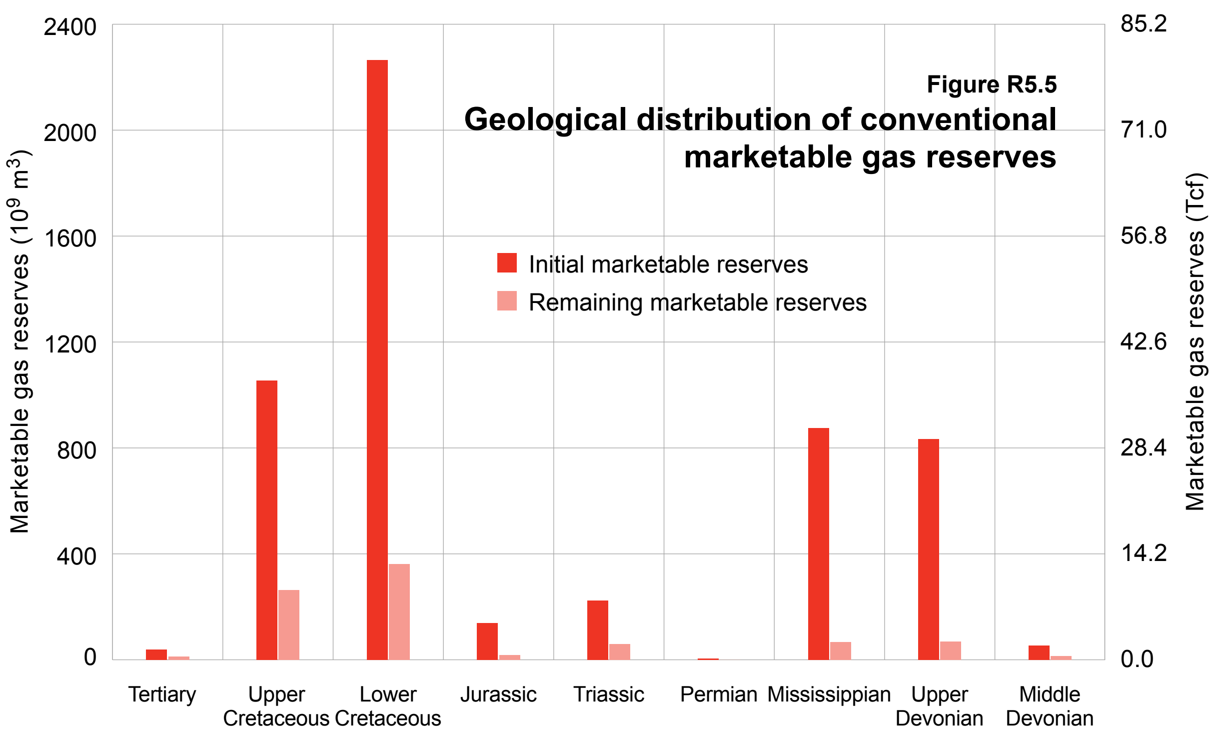


Figure R5.5
Geological distribution of conventional marketable gas reserves

Table R5.3 Distribution of natural gas reserves by pool size, 2014

Reserve range (10^6 m^3)	Pools		Initial established marketable reserves		Remaining established marketable reserves	
	#	%	10^9 m^3	%	10^9 m^3	%
3000+	234	0.5	3 096	56	455	53
1501–3000	175	0.4	367	7	59	7
1001–1500	185	0.4	227	4	31	4
501–1000	549	1.1	381	7	48	6
101–500	3 472	7.2	724	13	103	12
30–100	7 432	15.3	397	7	78	9
Less than 30	36 455	75.2	295	5	91	11
Total	**48 502**	**100.0**	**5 487**	**100**	**865**	**100**

The geological strata containing the largest remaining reserves are the Lower Cretaceous Mannville, Glauconitic, Ellerslie, and Viking, with 29 per cent; the Upper Cretaceous Cardium, Belly River, Milk River, and Medicine Hat, with 25 per cent; and the Mississippian Rundle, with 6 per cent. Together, these strata contain 60 per cent of the province's remaining established marketable gas reserves.

5.1.3.3 Geological Plays of Alberta

A geological play can be defined as a set of known or estimated oil or gas accumulations (discrete and continuous) within a petroleum system (a linked assemblage of source rock, migration routes, and ultimate traps) sharing similar geological, geographic, and temporal properties, such as source rock, migration pathways, timing, trapping mechanism, and hydrocarbon type. Estimates of volumes of hydrocarbon can be quantified for petroleum systems. The Western Canada Sedimentary Basin (WCSB) contains at least eight petroleum systems (as discussed in **Section 2.1.2**).

Each petroleum system has a number of stratigraphic intervals that can be subdivided into geological plays. The geographic limit of each play represents the limits of the geological elements that define the play. An example of a geological play in Alberta would be the Pembina Nisku Formation pinnacle-reef sour-gas play.

The AER is currently evaluating a number of geological plays. Numerous factors are considered in determining priority for review, such as industry activity, environmental impact, and safety. At this time, the AER is focusing on a number of plays within the Cardium, Montney, and Duvernay stratigraphic intervals. This geological framework will be used to generate play-by-play estimates of resources and reserves by the AER in forthcoming years.

5.1.3.4 Gas Commingling

Gas commingling is the unsegregated production of gas from more than one pool in a wellbore. As shown in **Table R5.4**, 27 per cent (16 674) of all gas pools in Alberta are commingled. This represents 517 10^9 m^3, about

60 per cent of remaining established reserves. In comparison, commingled pools represented only 33 per cent of remaining reserves in 2001.

In 2006, the AER issued orders establishing two development entities (DEs No. 1 and 2) that allow for the commingling of gas from certain formations within these areas without an application to the AER.[1] Subsequently, the AER amended the area described as DE No. 2 in 2010. The commingling of gas from certain formations within these areas has enabled operators to produce reserves from zones that otherwise would have been uneconomic to produce on their own.

Table R5.5 shows that DEs No. 1 and 2 have remaining established reserves of 57 10^9 m^3 and 201 10^9 m^3, respectively. The commingled gas reserves of DEs No. 1 and 2 account for about 30 per cent of Alberta's remaining established reserves.

5.1.3.5 Reserves of Conventional Natural Gas Containing Hydrogen Sulphide

Hydrogen sulphide (H_2S) is a naturally occurring substance present in many oil and gas reservoirs worldwide. Natural gas that contains more than 0.01 per cent H_2S is referred to as sour in this report.

In oil and gas reservoirs, H_2S is primarily generated through thermal and biological processes, both of which involve a reaction between dissolved sulphates and hydrocarbons. Thermally generated H_2S produces the highest concentrations of H_2S and occurs in reservoirs that have undergone diagenesis due to deep burial. Biologically generated H_2S is commonly found in shallower, lower temperature reservoirs, but can also occur in sewers, swamps, composts, and manure piles.

In Alberta, sour gas is found in several regions and formations across the province. The maps in **Figure R5.6** and **Figure R5.7** show the distribution of both 2014 and historical development of H_2S-bearing hydrocarbons within the clastic and carbonate successions of the WCSB. The division of these two maps reflects Alberta's basin architecture, which consists of a Cretaceous- to Permian-aged clastic wedge overlying a primarily Mississippian- and Devonian-aged carbonate succession (see **Section 2.1**).

The highlighted 2014 sour gas wells on the maps in **Figure R5.6** and **Figure R5.7** show areas of new sour gas development contrasted against historical drilling. As shown by these maps, much of the new H_2S-bearing hydrocarbon development in the province was from the drilling of oil wells.

Prominent sour gas production for 2014 included the Triassic-focused activity in the northwest, the development of Lower Cretaceous- and Jurassic-aged strata east of the foothills, and Cretaceous-aged enhanced oil recovery near the Saskatchewan border (**Figure R5.6**). Sour development within the carbonate-dominated strata (**Figure R5.7**) was focused on the oil-rich Devonian and Mississippian strata of the central and eastern plains.

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[1] A DE is a specified area consisting of multiple formations from which gas may be produced without segregation in the wellbore. These areas are described in AER orders DE 2006-1 and DE 2006-2 and are subject to certain criteria in the *Oil and Gas Conservation Rules*, section 3.051.

Table R5.4 Pool reserves as of December 31, 2014 (10^9 m^3)

	Number of commingled pools	Number of individual pools	Initial established reserves	Cumulative production	Remaining established reserves
Commingled pools	4 313	16 674	2 961	2 444	517
Noncommingled pools		44 189	2 525	2 177	348
Total			**5 486**	**4 621**	**865**

Table R5.5 Commingled pool reserves within development entities as of December 31, 2014 (10^9 m^3)

	Number of commingled pools	Number of individual pools	Initial established reserves	Cumulative production	Remaining established reserves
DE No. 1	720	2 249	402	345	57
DE No. 2	739	4 199	902	701	201
Total	**1 459**	**6 448**	**1 304**	**1 046**	**258**

As of December 31, 2014, sour gas accounted for about 22 per cent (189 10^9 m^3) of the province's total remaining established gas reserves and about 19 per cent of raw natural gas production in 2014. The average H_2S concentration of initial producible reserves of sour gas in the province at year-end 2014 was 8.2 per cent.

The distribution of reserves of sweet and sour gas provided in **Table R5.6** shows that 111 10^9 m^3, or about 59 per cent, of remaining sour gas reserves are in nonassociated pools. Since 2002, sour gas has consistently accounted for about 20 per cent of the total remaining marketable reserves. The distribution of sour gas reserves by H_2S content, shown in **Table R5.7**, indicates that 14 per cent (25 10^9 m^3) of remaining sour gas contains H_2S concentrations greater than 10 per cent, while 60 per cent (113 10^9 m^3) contains concentrations less than 2 per cent.

5.1.3.6 Reserves Methodology for Conventional Natural Gas

A detailed pool-by-pool list of reservoir parameters and reserves data for all conventional oil and gas pools as an electronic data file (see **Appendix C**) is available from the AER's Order Fulfillment Team.

The process of determining reserves takes into consideration geological, engineering, and economic factors. Though initial estimates contain a level of uncertainty, this level of uncertainty decreases over the life of the pool as more information becomes available and actual production is observed and analyzed. The initial reserves estimates are normally based on volumetric calculations that use bulk rock volume (based on isopach maps derived from geological interpretation of well log data) and initial reservoir parameters to estimate gas in-place at reservoir conditions. Drainage areas for single-well pools range from 200 hectares (ha) for regional sands with good permeability to 32 ha or less for low-permeability formations or geological structures limited in areal extent.

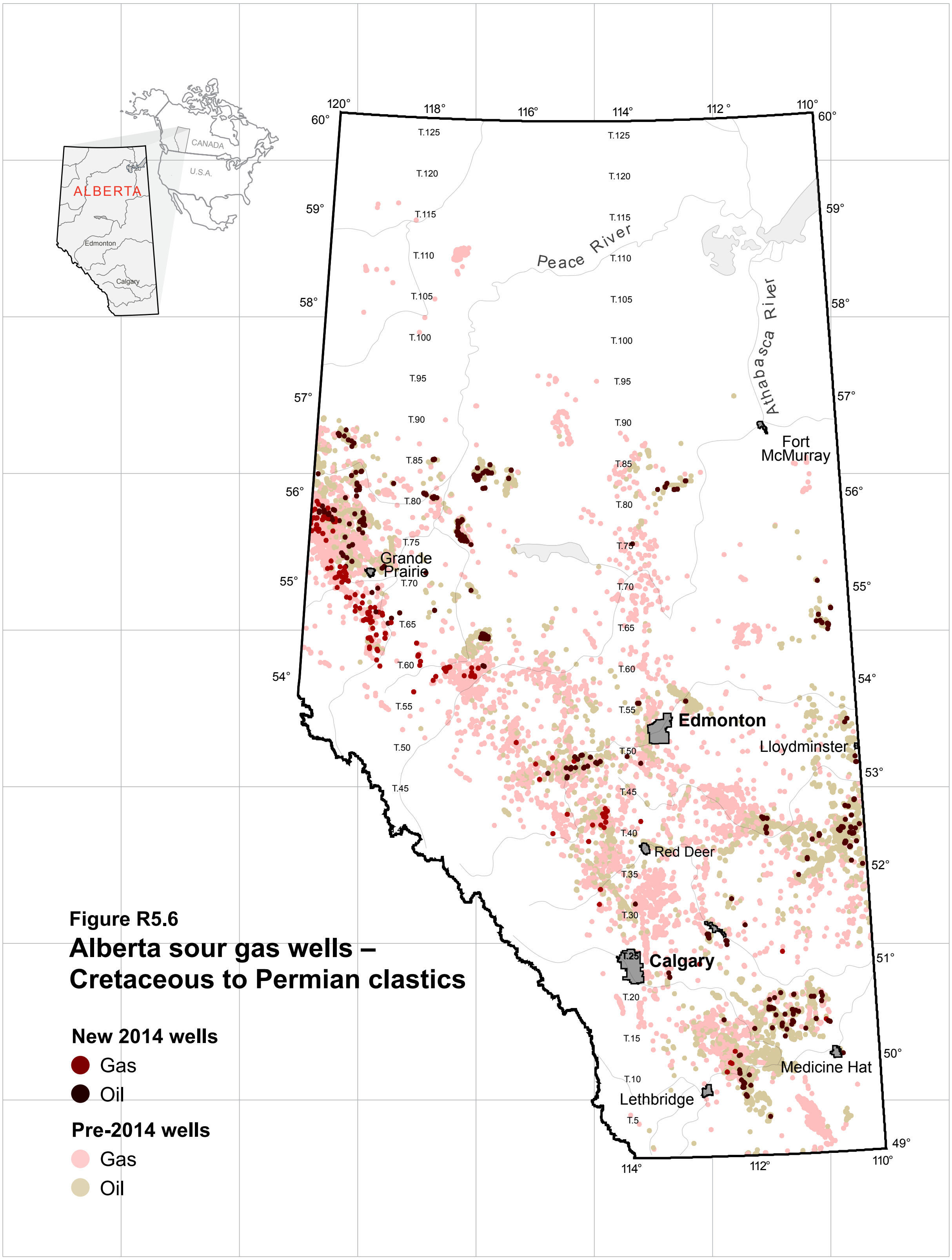


Figure R5.6
Alberta sour gas wells – Cretaceous to Permian clastics

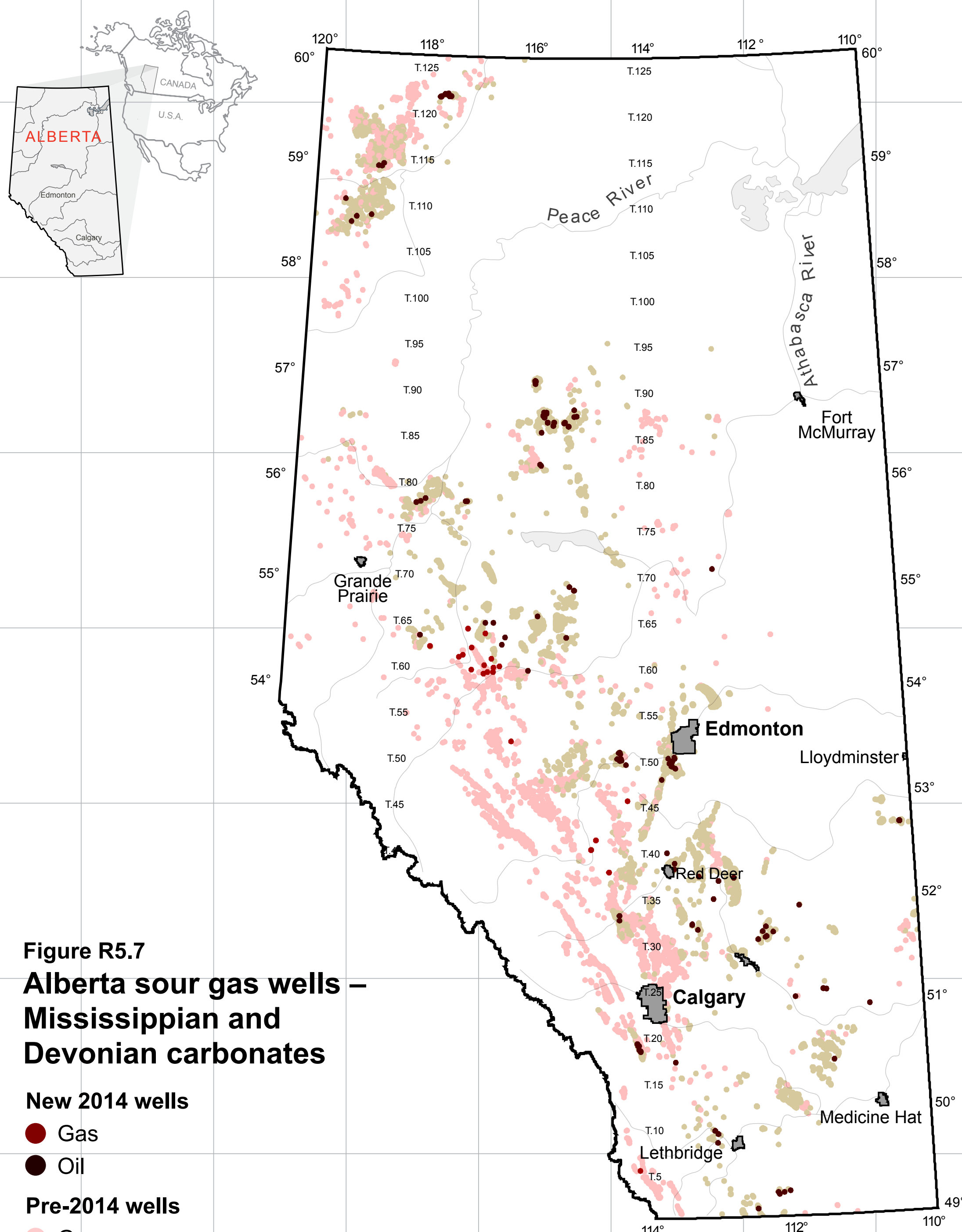


Figure R5.7

Alberta sour gas wells – Mississippian and Devonian carbonates

New 2014 wells

- Gas
- Oil

Pre-2014 wells

- Gas
- Oil

Table R5.6 Distribution of sweet and sour gas reserves, 2014

	Marketable gas (10^9 m^3)			Percentage	
Type of gas	**Initial established reserves**	**Cumulative production**	**Remaining established reserves**	**Initial established reserves**	**Remaining established reserves**
Sweet					
Associated and solution	908	729	179	16	21
Nonassociated	2 787	2 290	497	51	57
Subtotal	**3 695**	**3 019**	**676**	**67**	**78**
Sour					
Associated and solution	567	489	78	10	9
Nonassociated	1 225	1 114	111	22	13
Subtotal	**1 792**	**1 603**	**189**	**33**	**22**
Total	**5 487**	**4 622**	**865**[a]	**100**	**100**
	(195 Tcf)[b]	**(164 Tcf)**[b]	**(30.7 Tcf)**[b]		

[a] Reserves estimated at field plants.

[b] Tcf = trillion cubic feet.

Table R5.7 Distribution of sour gas reserves by H_2S content, 2014

	Initial established reserves (10^9 m^3)		Remaining established reserves (10^9 m^3)			
H_2S content in raw gas (%)	**Associated and solution**	**Nonassociated**	**Associated and solution**	**Nonassociated**	**Total**	**%**
Less than 2	421	454	60	53	**113**	60
2–10	103	406	13	38	**51**	27
10–20	32	210	4	9	**13**	7
20–30	11	49	1	4	**5**	3
Over 30	0	105	0	7	**7**	4
Total[a]	**567**	**1 224**	**78**	**111**	**189**	**100**
Percentage	32	68	41	59		

[a] Any discrepancies are due to rounding.

Converting gas volume in-place to specified standard conditions at the surface requires knowing the reservoir pressure, temperature, and gas content. A recovery factor is applied to the in-place volume to yield the recoverable reserves—the volume that will actually be produced to the surface. Given the low viscosity and high mobility of natural gas, recoveries typically range from 70 to 90 per cent. However, low-permeability gas reservoirs and reservoirs with underlying water may only recover 50 per cent or less of the in-place volume.

Once a pool has been on production for some time, a material balance analysis involving the decline in pool pressure can be used as an alternative to the volumetric estimation to determine in-place resources. Material balances are more accurate when applied to high-permeability, nonassociated, and noncommingled gas pools.

An analysis of production decline data is the primary method of determining recoverable reserves, given that most of the larger pools in the province have been in decline for many years. When combined with an estimate of the in-place resources, it also provides a practical, realistic estimate of the pool's recovery factor.

The procedures described above generate an estimate of the initial established reserves of raw gas. The raw natural gas reserves must be converted to a marketable volume (i.e., the volume that meets pipeline specifications) by applying a surface loss or shrinkage factor. Based on the gas analysis for each pool, a surface loss is estimated using an algorithm that reflects expected recovery of liquids (ethane, propane, butanes, and pentanes plus) at field plants. Typically, 5 per cent is added to account for loss due to lease fuel (estimated at 4 per cent) and flaring. Surface losses range from 3 per cent for pools containing sweet dry gas to over 30 per cent for pools with raw gas containing high concentrations of H_2S and gas liquids. Therefore, marketable gas reserves of individual pools in the AER's gas reserves database reflect expected marketable reserves after processing at field plants. The pool reserve numbers published by the AER represent estimates for in-place resources, recoverable reserves, and associated recovery factors based on the most reasonable interpretation of available information from volumetric, production decline, and material balance estimates.

Additional liquids contained in the gas stream leaving the field plants are extracted downstream at straddle plants. Exceptions to this are the gas shipped to Chicago through the Alliance pipeline and some of the dry southeastern Alberta gas.

It is expected that about 28.7 10^9 m^3 of liquids, on a gas equivalent basis, will be extracted at straddle plants, thereby reducing the remaining established reserves of marketable gas (estimated at the field plant gate) from 865.3 10^9 m^3 to a volume of 836.6 10^9 m^3.

Before extraction, the estimated average composition of the hydrocarbon component without impurities is about 92 per cent methane, 5 per cent ethane, and lesser amounts of propane, butanes, and pentanes plus. **Figure R5.8** shows the average percentage of remaining established reserves of each hydrocarbon component expected to be extracted at field and straddle plants. For example, of the total ethane content in raw natural gas, about 25 per cent is expected to be removed at field plants and an additional 40 per cent at straddle plants. Therefore, the AER estimates the reserves of liquid ethane that will be extracted based on 65 per cent of the total raw ethane gas reserves. The remaining 35 per cent of the ethane is left in the marketable gas and sold for its heating value. This ethane represents a potential source of future ethane supply for Alberta.

Reserves of NGLs are discussed in more detail in **Section 6**.

5.1.3.7 Multifield Pools

Pools that extend over more than one field are classified as multifield pools and are listed in **Section Table B.5** in **Appendix B**. For each multifield pool, the individual remaining established reserves assigned to each field and the total remaining established reserves for the multifield pool are shown.

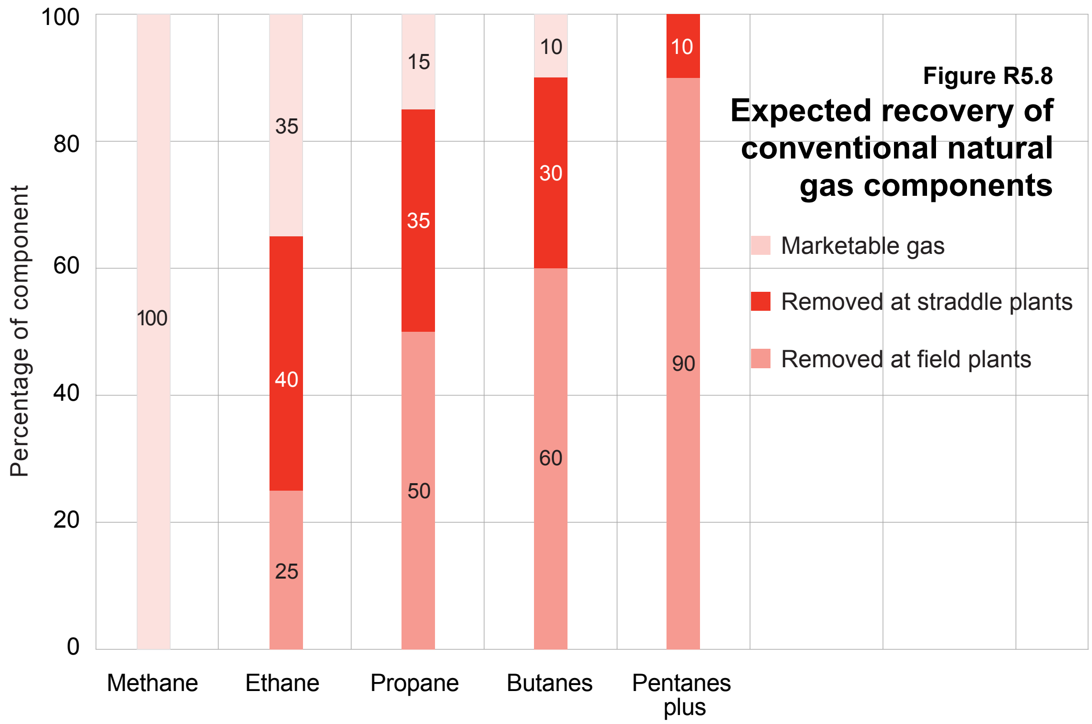


Figure R5.8
Expected recovery of conventional natural gas components

5.1.4 Established Reserves of CBM

CBM is the methane gas found in coal, both as adsorbed gas and as free gas. Unlike conventional gas, which occurs as discrete accumulations, or pools, CBM most often occurs in interconnected coal seams within defined stratigraphic zones as laterally continuous accumulations or deposits.

CBM may contain small amounts of carbon dioxide and nitrogen (usually less than 5 per cent). H_2S is not normally associated with CBM production as the coal adsorption coefficient for H_2S is far greater than for methane. The heating value of CBM is generally about 37 MJ/m^3.

5.1.4.1 CBM Potential by Geological Strata

Based on the analysis of thousands of coalholes and oil and gas wells, coal is known to underlie most of central and southern Alberta—one of the largest geographical extents of continuous coal in North America. Coal seams occur as layers or beds within several Cretaceous coal zones. While individual coal seams can be laterally discontinuous, coal zones can be correlated very well over regional distances. All coal seams contain CBM to some extent and each seam is potentially capable of producing CBM. Currently, the AER recognizes CBM reserves in the Horseshoe Canyon Formation and the Mannville Group horizons.

An individual CBM zone is defined as all coal seams within a formation separated by less than 30 m of non-coal-bearing strata or separated by a previously defined conventional gas pool. Several individual producing coal seams in one CBM zone are considered to be one CBM pool for regulatory and administrative purposes. For administrative purposes, previous pools limited by field boundaries have been converted to multifield CBM pools. However, as multifield pools are still problematic when grouping CBM resource and reserve estimates, the AER groups CBM volumes into deposit-based play areas.

5.1.4.2 CBM Deposits, Play Areas, and Play Subareas

Although CBM is regulated and administered as if it existed in pools, CBM accumulations exist more as deposits. The AER assesses CBM deposits for reserve determination in a manner similar to the way it assesses oil sands deposits. CBM deposits are stratigraphic intervals that extend over a large geographic area and may include one or more CBM zones. Unlike oil sands deposits, however, the AER has yet to formally define CBM deposits because it is still monitoring development activities. Currently, CBM deposits are informally based on formations, with the two main CBM deposits being the Horseshoe Canyon and the Mannville. Within each of these deposits, development activities have, until now, been concentrated mainly in a single play area.

While Mannville activity is clustered almost exclusively in the Corbett area, the more widespread Horseshoe Canyon play occurs over a large area in central Alberta between Calgary and Edmonton. Currently, the Horseshoe Canyon play area is within the AER-designated DE No. 1 and the southeastern Alberta gas system. The current play areas for the Horseshoe Canyon and Mannville deposits are shown in **Figure R5.9**.

Although coal zones are regionally extensive, the values of reservoir parameters used for reserves estimates are determined locally. As a result, for reserves estimation and reporting purposes, the large central Alberta play area of the Horseshoe Canyon deposit is divided into subareas based on reservoir and production profile differences defined by data from control wells within the deposit. The location of the Horseshoe Canyon play subareas is also shown on **Figure R5.9**.

5.1.4.3 CBM Reserves Determination Method

CBM initial established reserve values remain generally unchanged from 2013. The AER is currently reviewing the process for determining CBM reserves in Alberta.

Current reserve estimates were generated using three-dimensional block models to estimate in-place CBM resources for each play area or subarea. Desorption data was used on a zonal basis by applying gas content trends from core to all coals in each zone to estimate in-place CBM resources. Desorption values from drill cuttings were used to validate the continuity of the zonal trends from core.

Current reserve estimates were determined by applying an average recovery factor based on analysis of control well data for each play subarea. These recovery factors are shown for each subarea in **Table R5.8**. The method of determining reserves depends on flowmeter values and changes in reservoir pressure as determined by qualitatively comparing annual measurements in each CBM zone. If the data or production reporting is missing, then the result is assumed to be zero. Future analysis is expected to improve estimates of recovery factors. CBM data are available on two systems from the AER: the integrated geological database (summarized net pay data) and the coalhole database (individual coal seam thickness picks).

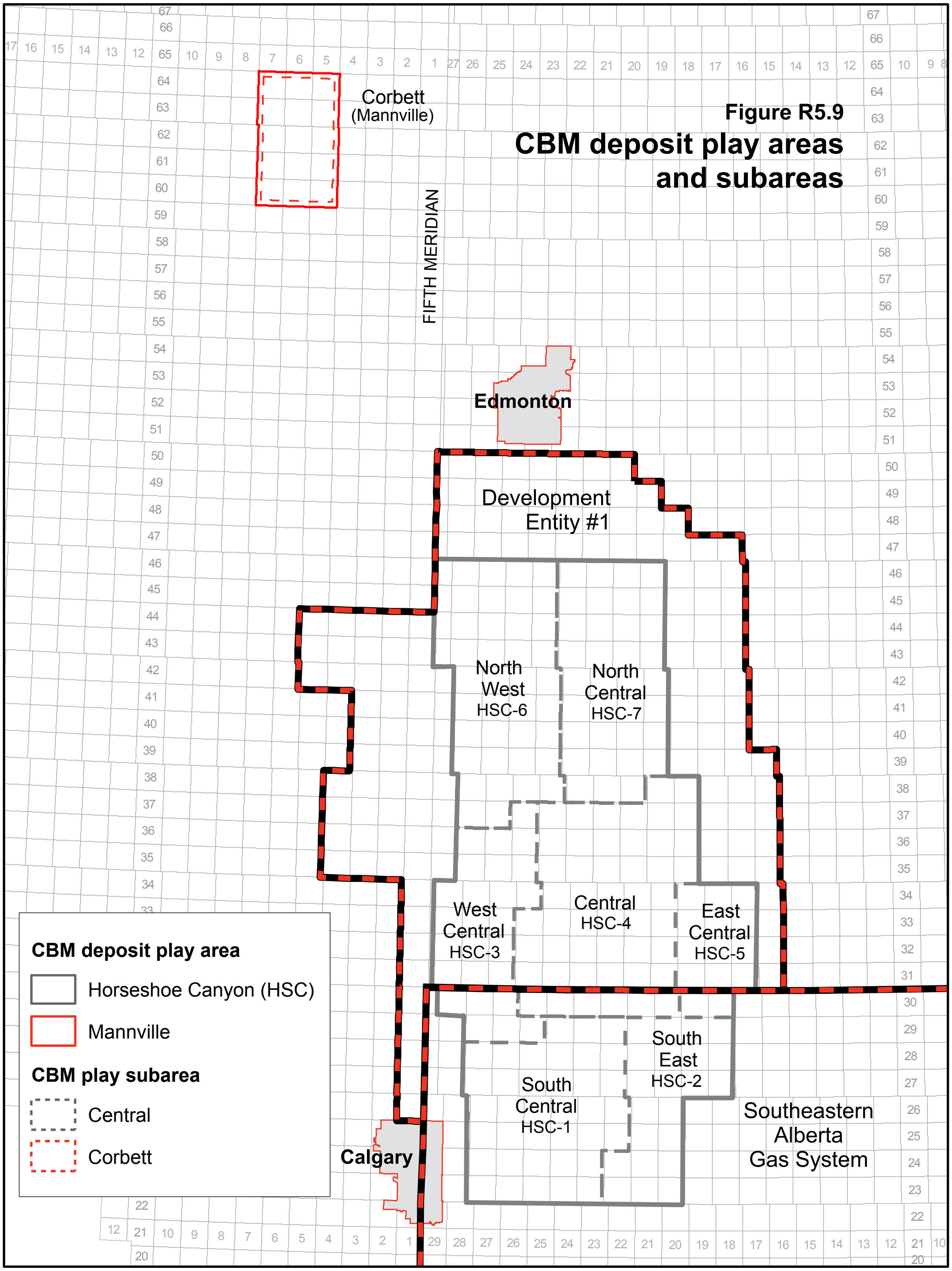


Figure R5.9
CBM deposit play areas and subareas
Corbett (Mannville)
FIFTH MERIDIAN
Edmonton
Development Entity #1
North West HSC-6
North Central HSC-7
West Central HSC-3
Central HSC-4
East Central HSC-5
South Central HSC-1
South East HSC-2
Southeastern Alberta Gas System
Calgary
CBM deposit play area
Horseshoe Canyon (HSC)
Mannville
CBM play subarea
Central
Corbett

Table R5.8 CBM gas in-place and reserves by deposit play area, 2014

Deposit and play subareas	Average net coal thickness (m)	Coal reservoir volume (10^9 m^3)	Estimated gas content (m^3 gas/ m^3 coal)	Initial gas in-place (10^9 m^3)	Average recovery factor (%)	Initial established reserves (10^9 m^3)	Cumulative production (10^9 m^3)	Remaining established reserves (10^9 m^3)
Horseshoe Canyon[a]								
HSC-1	10.1	35.37	2.95	104.38	27	28.56	8.61	19.95
HSC-2	4.3	9.04	1.06	9.61	25	2.37	0.66	1.71
HSC-3	5.8	13.91	2.41	33.56	30	10.19	6.09	4.10
HSC-4	6.4	28.39	1.72	48.84	34	16.47	15.78	0.69
HSC-5	3.0	3.93	1.11	4.37	26	1.13	0.90	0.23
HSC-6	3.5	8.67	1.57	13.58	32	4.41	4.41	0.00
HSC-7	4.4	14.74	1.30	19.19	46	8.88	8.88	0.00
Undefined[b]	-	-	-	-	-	2.18	2.18	0.00
Subtotal	**5.4**	**114.05**	**2.05**[c]	**233.53**	**32**[c]	**74.19**	**47.51**	**26.68**
Mannville								
Corbett	4.9	6.97	9.73	67.86	42	28.18	7.04	21.14
Undefined[b]	-	-	-	-	-	0.72	0.72	0.00
Total		**121.02**		**301.39**	**34**[c]	**103.09**	**55.27**	**47.82**

[a] Includes Upper Belly River CBM.

[b] Most of the undefined areas are for tests in the Mannville coals, but also include a few Horseshoe Canyon, Ardley, and Kootenay wells with minor production and many Belly River recent recompletions.

[c] Volume-weighted average.

5.1.4.4 Detail of CBM Reserves and Well Performance

Horseshoe Canyon coals, which are mainly gas charged, with little or no pumping of water required, remain the main focus of industry and currently have the highest established reserves (see **Table R5.8**). New data have supported including additional areas within many of the Horseshoe Canyon CBM play subareas. In subarea 1, coals are deeper and have a higher gas content, making this area one of the largest initial established reserves of CBM in the Horseshoe Canyon play.

5.1.4.5 Commingling of CBM with Conventional Natural Gas

The first production of CBM in Alberta was attempted in the 1970s, but the first CBM pool was not defined by the AER until 1995. Significant development with commercial production began in 2002. The actual CBM production to date continues to be uncertain because of the difficulty differentiating CBM from conventional gas production where commingled production occurs.

Gas commingling is the unsegregated production of gas from more than one pool in a wellbore. For CBM, this includes the commingling of two or more CBM zones, as well as the commingling of one or more CBM zones with one or more conventional gas pools.

As the Horseshoe Canyon and Belly River Formations generally contain "dry" CBM with little or no pumping of water required, the commingling of CBM and other conventional gas pools is common. Because many of the sandstone gas reservoirs in these strata may be marginally economic or uneconomic if produced separately, commingling with CBM can be beneficial from a resource conservation perspective. In some circumstances, commingling can have the additional benefit of minimizing surface impact by reducing the number of wells needed to extract the same resource.

CBM hybrid wells lack segregated reservoir data from commingled zones, making reserve estimation more difficult. Many hybrid wells report only CBM production, even though analysis of the wells indicates that there is unsegregated production of both CBM and conventional gas. Recompleted wells with new CBM production may not report to a separate production occurrence. To address these data constraints, the following was done for wells with commingled production:

- Wells with completions that were determined to be only in coal were assigned as CBM-only production.
- The CBM production contribution from hybrid wells was interpolated from more than 1300 CBM control wells and numerous other wells with confirmed CBM-only production. The volume of CBM production was then subtracted from the total volume to give the conventional gas production.
- CBM production from conventional wells recompleted for CBM and not reported separately was included. An administrative process is in place to correct for the CBM production in these cases.

5.1.5 Shale Gas Resources

Shales are the traditional source rocks for conventional hydrocarbon accumulations and act as a seal for conventional reservoirs. More recently, organic-rich shales have become a target for the production of gas, natural gas liquids, and oil.

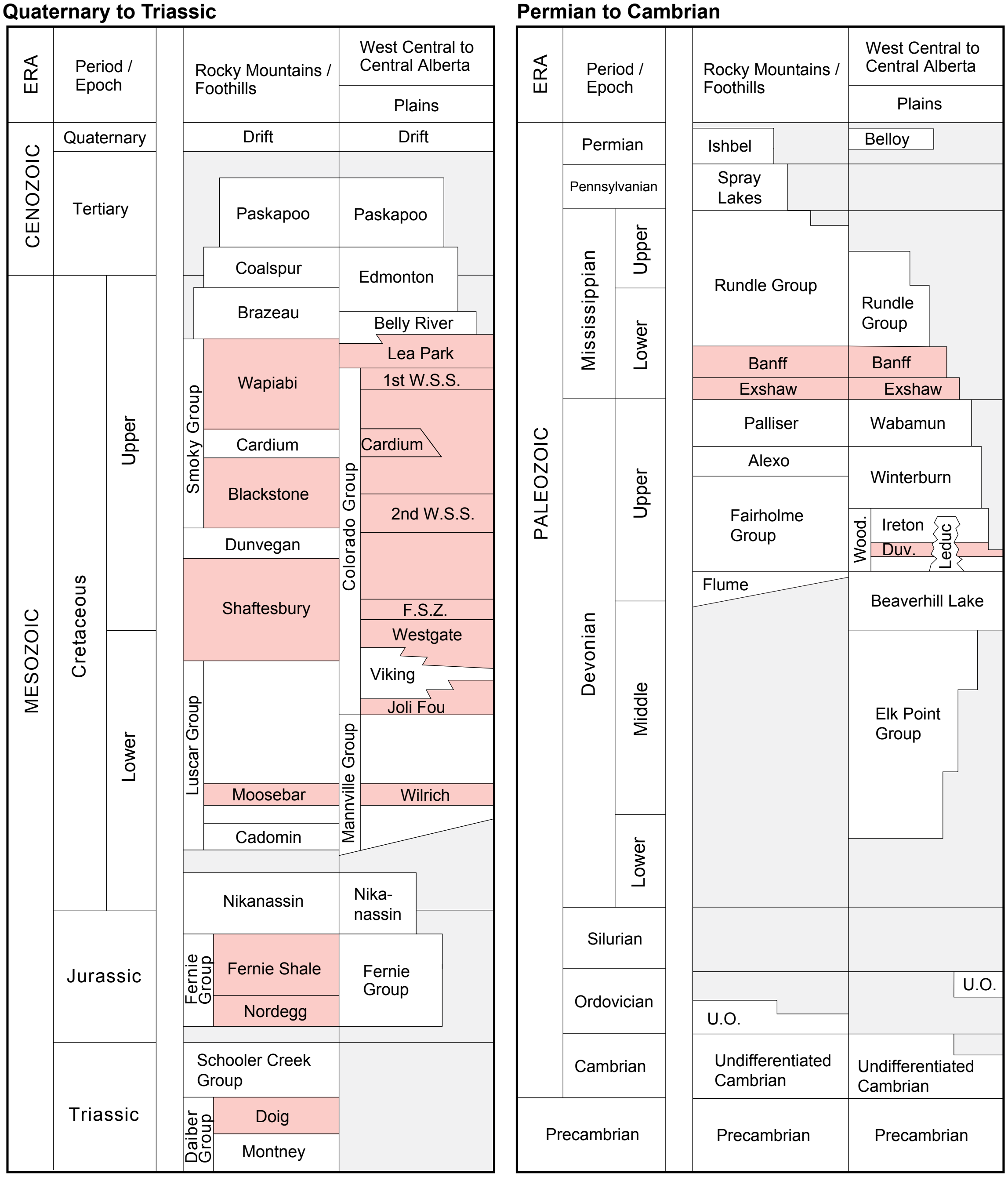
Typically, these fine-grained rocks have an extremely low matrix permeability, and stimulation is required to produce fluids from the rock. Shale gas or shale oil is not restricted to shale since claystones, mudstones, siltstones, fine-grained sandstones, and carbonates can also be found within potential shale gas strata. (See the AER's recent study on shale- and siltstone-hosted hydrocarbon resources in **Section 2.2.2)**.

More than 15 shale formations exhibit a potential for shale gas, natural gas liquids, or oil. The generalized stratigraphic chart of formations in **Figure R5.10** shows the formations (indicated with red shading) with organic matter that could potentially produce gas or oil. Not all of these formations are source rocks (i.e., are organic rich); some contain small amounts of organic matter and may be more like low-permeability strata or aquitards than organic-rich shale.

Exploration for shale gas, natural gas liquids, and oil is taking place in many of the formations highlighted in **Figure R5.10**. Receiving most of the attention are the Duvernay (Woodbend Group), Banff/Exshaw, and Nordegg (Fernie Group) Formations as these strata are rich in natural gas liquids and oil. The depth from the surface to

Figure R5.10

Potential shale gas strata



Abbreviations:
1st W.S.S. – First White Speckled Shale
2nd W.S.S. – Second White Speckled Shale
Duv. – Duvernay
F.S.Z. – Fish Scales Zone
U.O. – Undifferentiated Ordovician
Wood. – Woodbend Group

Potential shale gas strata
Absent

the shale formations increases westwards in Alberta. The deeper formations typically have a higher formation pressure, which is favourable for shale gas exploration.

The geographic distribution of significant shale gas horizons in the upper half of the WCSB is shown in **Figure R5.11**. The lower half of the WCSB is shown in **Figure R5.12**.

Since shale gas is in the early stages of development in Alberta, the AER does not report reserves for shale gas at this time. As more data become available, the AER will look at the possibility of creating reserve values in the future.

5.1.6 Ultimate Potential of Conventional Natural Gas

The Alberta Energy and Utilities Board (EUB; a predecessor of the AER) and the National Energy Board (NEB) jointly released *EUB/NEB Report 2005-A: Alberta's Ultimate Potential for Conventional Natural Gas*, an updated estimate of the ultimate potential for conventional natural gas. The EUB adopted the medium case of the report, representing a volume of 6276 10^9 m^3 (223 Tcf) "as is" or 6528 10^9 m^3 (232 Tcf) at the equivalent standard heating value of 37.4 MJ/m^3, as Alberta's ultimate potential. This estimate does not include unconventional gas, such as CBM.

Figure R5.13 shows the historical and forecast growth in initial established reserves of marketable gas. Historical growth up to 2014 equalled 5756 10^9 m^3. **Figure R5.14** plots production and remaining established reserves of marketable gas compared with the estimate of ultimate potential.

Table R5.9 gives details about the ultimate potential of marketable gas, with all values shown both "as is" and converted to the equivalent standard heating value of 37.4 MJ/m^3. It shows that initial established marketable reserves of 5487 10^9 m^3, or 87 per cent of the ultimate potential of 6276 10^9 m^3 ("as is" volumes), have been discovered as of year-end 2014. This leaves 789 10^9 m^3, or 13 per cent, as yet-to-be-discovered reserves. Cumulative production of 4622 10^9 m^3 at year-end 2014 represents 74 per cent of the ultimate potential, leaving 1654 10^9 m^3, or 26 per cent, available for future use.

The regional distribution of initial established reserves, remaining established reserves, and yet-to-be-established reserves is shown by PSAC area in **Figure R5.15**. It shows that PSAC Area 2 contains 39 per cent of the remaining established reserves, and PSAC Area 7 contains 29 per cent of the yet-to-be-established reserves. Although most gas wells have been drilled in the southern plains (PSAC Areas 3, 4, and 5), **Figure R5.15** shows that, based on *EUB/NEB Report 2005-A*, Alberta conventional natural gas supplies will continue to depend on significant new discoveries in all PSAC areas.

5.1.7 Ultimate CBM Gas In-Place

The Alberta Geological Survey (AGS), in *Earth Sciences Report 2003-03*, estimated that there are 14 trillion (10^{12}) m^3 (500 Tcf) of gas in-place within all of the coal in Alberta. This estimate is accepted as the initial determination of Alberta's ultimate CBM gas in-place (see **Table R5.10)**. However, due to the early stage

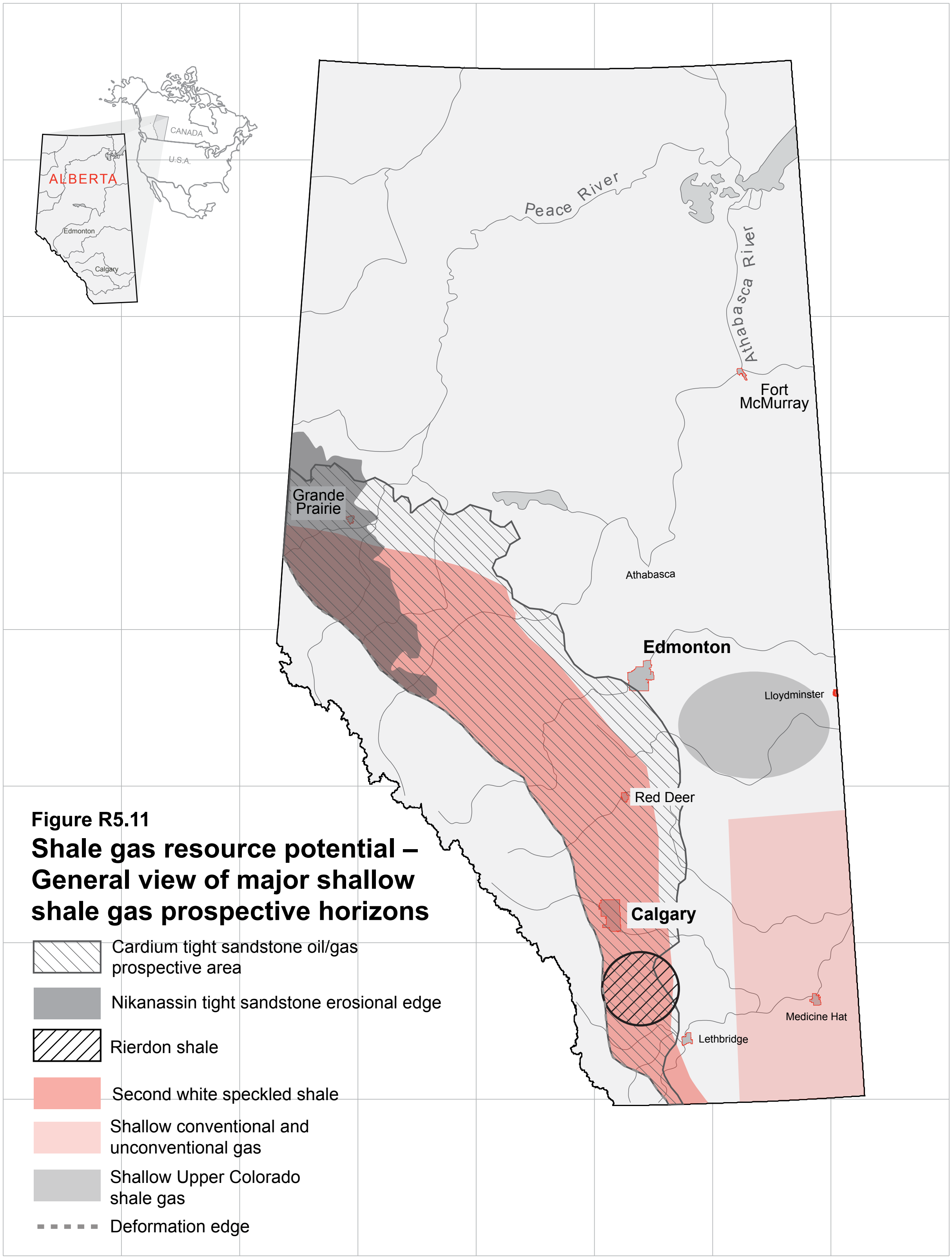


Figure R5.11
Shale gas resource potential – General view of major shallow shale gas prospective horizons

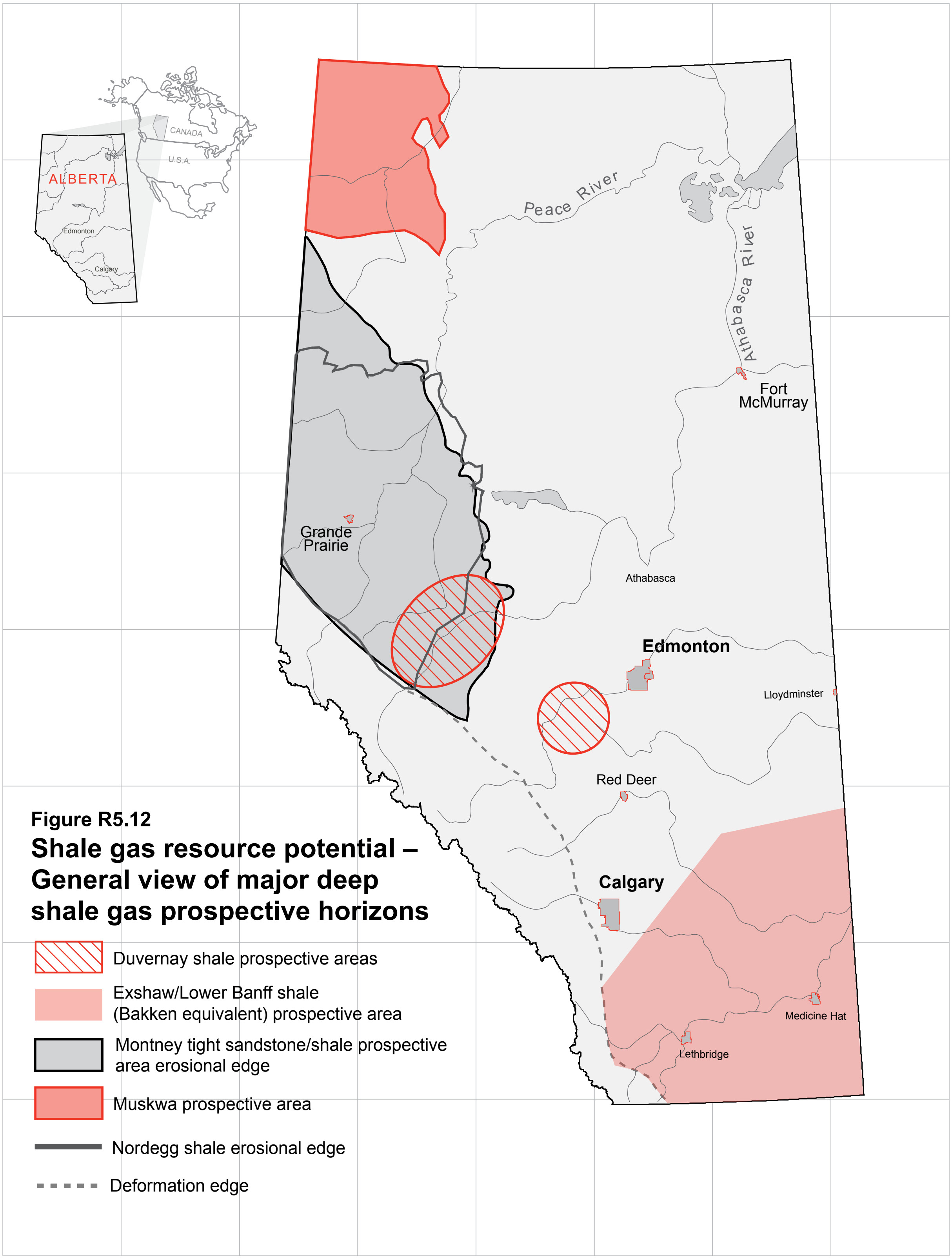


Figure R5.12
Shale gas resource potential – General view of major deep shale gas prospective horizons

Figure R5.13
Growth of initial established reserves of conventional marketable gas

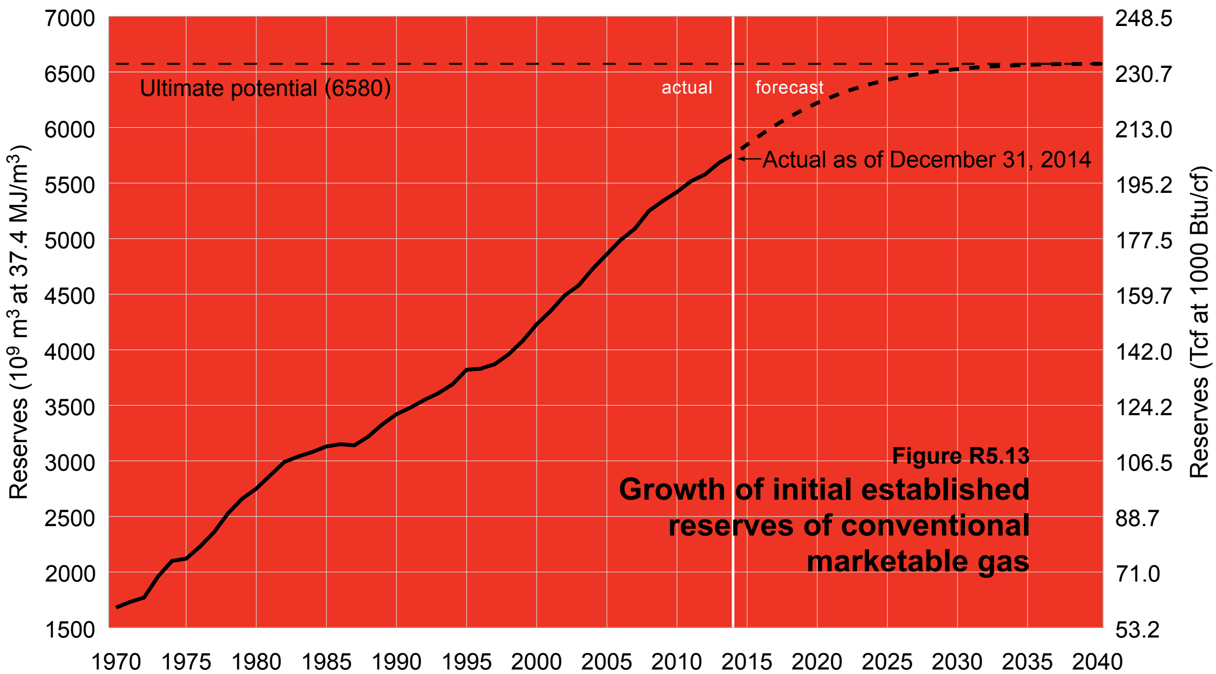
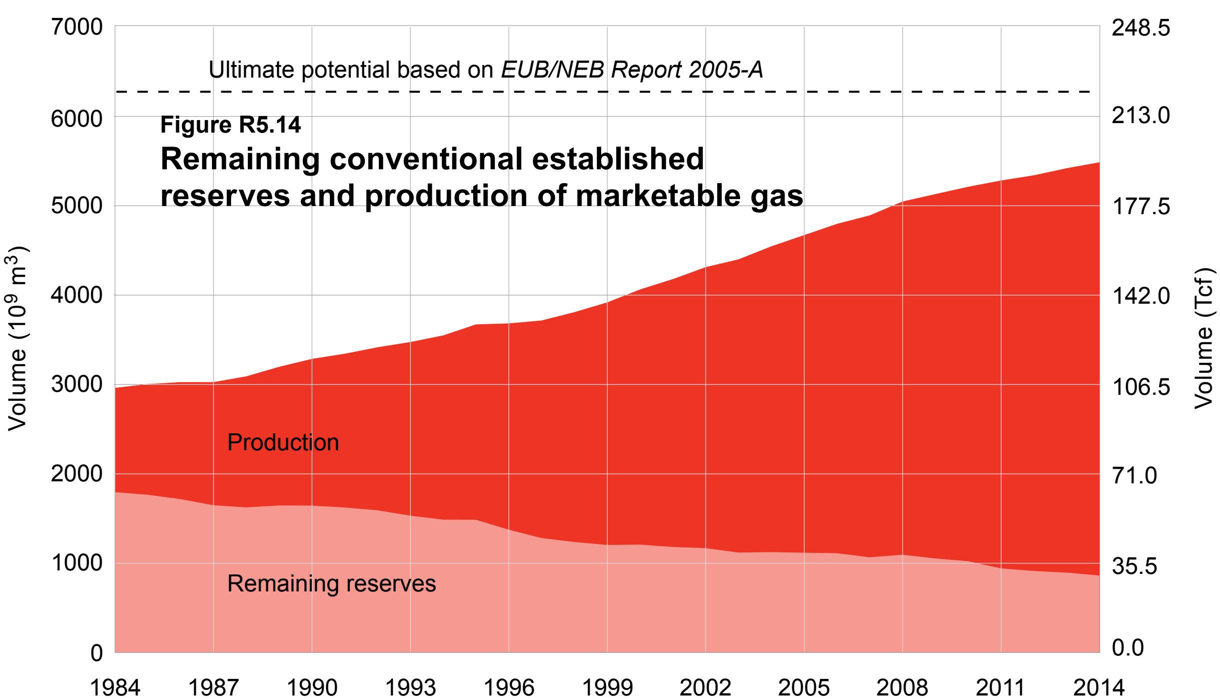


Figure R5.14
Remaining conventional established reserves and production of marketable gas



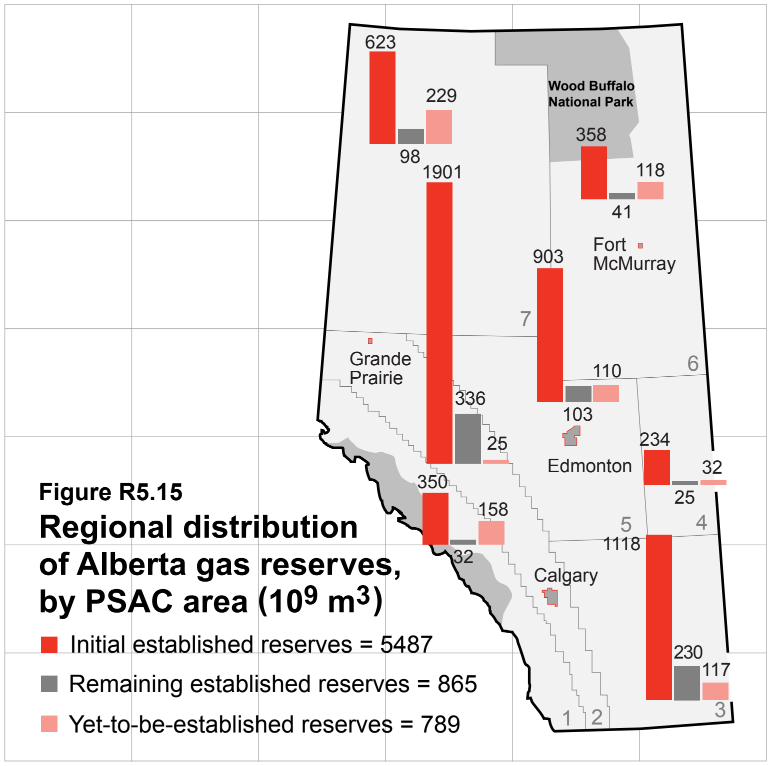


Figure R5.15
Regional distribution of Alberta gas reserves, by PSAC area (10^9 m^3)

- Initial established reserves = 5487
- Remaining established reserves = 865
- Yet-to-be-established reserves = 789

Table R5.9 Remaining ultimate potential of marketable conventional gas, 2014 (10^9 m^3)

	Gross heating value	
	As is (39.2 MJ/m³)	**At 37.4 MJ/m³**
Ultimate potential	6 276	6 584
Minus initial established reserves	-5 487	-5 756
Yet-to-be-established reserves	**789**	**828**
Initial established reserves	5 487	5 756
Minus cumulative production	-4 622	-4 848
Remaining established reserves	**865**	**908**
Yet-to-be-established reserves	789	828
Plus remaining established reserves	+865	+908
Remaining ultimate potential	**1 654**	**1 736**

Table R5.10 Ultimate CBM gas in-place

Area	10^{12} m^3	Tcf[a]
Upper Cretaceous/Tertiary – Plains	4.16	148
Mannville coals – Plains	9.06	321
Foothills/Mountains	0.88	31
Total	**14.10**	**500**

Source: *EUB/AGS Earth Sciences Report 2003-03*.

[a] Tcf = trillion cubic feet.

of CBM development and the resulting uncertainty of recovery factors, the recoverable portion—the ultimate potential—has yet to be determined.

Although not a type of natural gas, synthetic gas has potential in Alberta to be produced from coal and other sources. Synthetic gas from coal is discussed in **Section 8**.

5.1.8 Ultimate Potential of Shale Gas

While the AER has yet to do a full provincial analysis of natural gas in shale-hosted reservoirs, the recent report *Energy Briefing Note – The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta* (discussed in **Section 2.3.3**) has given an estimate for the Montney Formation, one of the largest shale formations likely to produce some volumes of natural gas in the future. The report stated an ultimate potential of 5042 10^9 m^3 of natural gas in the Alberta portion of the Montney Formation.

5.2 Supply of and Demand for Natural Gas

This section discusses both conventional and unconventional natural gas, with unconventional gas including CBM and shale gas. As previously discussed in **Section 5**, any unconventional tight gas production volumes are included within conventional natural gas production reporting.

In projecting marketable natural gas production, the AER considers three components: expected production from existing producing wells, expected production from new wells placed on production, and gas production from oil wells. The AER also takes into account its estimates of the remaining established and yet-to-be established reserves of natural gas in the province. The AER projects conventional gas production from oil wells and gas wells separately from CBM wells, the forecasts are then combined and referred to as total gas production in Alberta. The production of natural gas from shale horizons remains limited and, consequently, no forecast is given in this report. However, this may be revisited in future reports as more information becomes available. Highlights of annual activity can be found in **Table S5.1**.

Table S5.1 highlights 2013 and 2014 actual production and wells placed on production in Alberta. Total production increased by about 2.3 per cent in 2014 over 2013, despite a drop in production from CBM wells. Wells placed on production also increased in 2014 by 32.3 per cent compared to 2013 because of a strong increase in horizontally completed wells using multistage fracturing technology.

Table S5.1 Natural gas production and wells placed on production change highlights (10^6 m^3/d)

	2014	2013	Change	Per cent (%)[a]
Marketable production				
Conventional	265.2	258.7	+6.5	+2.5
CBM	19.0	20.9	−1.9	−9.0
Shale	3.0	1.3	+1.8	+139.8
Total	**287.3**	**280.9**	**+6.4**	**+2.3**
Number of wells placed on production				
Vertical	601	577	+24	+4.2
Horizontal				
HMSF[a]	974	606	+368	+60.7
Other	107	88	+19	+21.6
Subtotal	1 081	694	+387	+55.8
Total	**1 682**	**1 271**	**411**	**+32.3**

[a] Per cent changes are based on annual production volumes.

[b] Horizontal wells reported as being completed with hydraulic multistage fracturing (HMSF) technology.

5.2.1 Marketable Natural Gas Production – 2014

Cold weather during the winter of 2013–14 across North America resulted in increased demand for natural gas, triggering an increase in drilling activity for natural gas, causing a year-over-year increase in natural gas production for the first time since 2007. In 2014, total marketable natural gas production in Alberta, including unconventional production, increased from 280.9 10^6 m^3/d in 2013 to 287.3 10^6 m^3/d. In 2014, natural gas from conventional gas and oil wells placed on production, at 265.2 10^6 m^3/d (standardized to 37.4 MJ/m^3), represented 92.3 per cent of production. The remaining 7.7 per cent of gas supply came from CBM and shale gas wells placed on production.

Total production from identified CBM and CBM hybrid wells[2] placed on production decreased about 9.0 per cent in 2014 to 19.0 10^6 m^3/d. Gas production from gas wells completed in the Horseshoe Canyon play area was 17.5 10^6 m^3/d, or about 92.0 per cent of total CBM production. Gas production from the Mannville Group averaged 1.5 10^6 m^3/d. Total production volume includes production from gas wells outside the defined CBM subareas.

The percentage of sour natural gas relative to total gas production decreased from 31 per cent in 2000 to 19 per cent in 2014 because of a decline in production from the large sour gas pools in the province.

Marketable natural gas production volumes for conventional gas are calculated based on production data from the supply and disposition of marketable gas section of *ST3: Alberta Energy Resource Industries Monthly Statistics*, as shown in **Table S5.2**. Gas production from CBM and shale gas wells placed on production is determined separately.

[2] Wells commingled with conventional gas are defined as CBM-hybrid wells.

Table S5.2 Conventional marketable natural gas volumes (10^9 m^3)

Conventional marketable gas production	2014
Total raw gas supply including storage withdrawals	123.2
Minus production from CBM and hybrid wells placed on production	−7.0
Minus production from shale gas wells placed on production	−1.1
Total conventional raw gas production	115.1
Minus storage withdrawals	−8.2
Net raw gas production	106.9
Minus total injection	−1.8
Net raw gas production	105.1
Minus processing shrinkage—raw	−7.3
Minus flared—raw	−0.9
Minus vented—raw	−0.5
Minus fuel—raw	−10.2
Plus storage injections	6.9
Conventional marketable gas production at "as is" conditions	93.1
Conventional marketable gas production at 37.4 MJ/m^3	96.8
Average daily rate of conventional marketable gas at 37.4 MJ/m^3	(265.2 10^6 m^3/d)

Major factors affecting Alberta natural gas production are basin maturity, drilling and well activity, the location of Alberta's reserves, well production characteristics, gas liquids content, market demand, and natural gas prices and their volatility. In 2014, three factors played a predominate role in increasing both natural gas activity and production growth: continued drilling of horizontal wells using multistage fracturing technology, increased demand, and continued focus on wet gas (liquids rich) natural gas targets, particularly condensate.

In 2014, the Alberta Energy Company storage hub (AECO-C) daily price averaged Cdn$4.21 per gigajoule (GJ), up a significant 38.9 per cent from the 2013 daily average of Cdn$3.03/GJ.[3] The increase in price is largely due to a cold winter that increased demand and reduced inventories. Following the winter, inventories began to build with weakening seasonal demand, resulting in a decrease in prices for the latter half of the year.

5.2.2 Conventional Natural Gas – 2014

Gas wells placed on production include newly drilled wells placed on production and recompletions into new zones of existing wells. This section identifies recompletions as those wells placed on production at least one year after the finished drilling date. Continuing with a change introduced in last year's report, the term "wells placed on production" will be used in place of the term "connections," which had been used in prior years. As

[3] A DE is a specified area consisting of multiple formations from which gas may be produced without segregation in the wellbore. These areas are described in AER orders DE 2006-1 and DE 2006-2 and are subject to certain criteria in the *Oil and Gas Conservation Rules*, section 3.051.

with connections, wells placed on production refers to wells that have been physically connected to gathering infrastructure and are reporting production. This differs from drilling, in that drilling does not infer production and does not reflect multiple connections in one wellbore. In addition, starting with this report, the definition of "producing wells" has been revised to include drain wells.[4] As a result, the historical well counts have been revised and are higher than had been reported previously. Well productivity calculations are also affected by this new definition of producing wells.

5.2.2.1 Conventional Natural Gas Wells Placed on Production

Figure S5.1 shows the number of conventional gas wells placed on production in Alberta in the last two years by PSAC area. In 2014, 1300 new conventional gas wells were placed on production in the province—the first time the number of new conventional gas wells placed on production has increased on a year-over-year basis since 2006. When compared to the slightly revised 2013 figure, the number of gas wells placed on production in 2014 increased by 43.2 per cent. A substantial part of this increase is from an increasing number of wells being placed on production in PSAC Area 2, in response to an increase in price due to an unusually cold winter across North America and the wet nature of these wells.

Conventional gas well activity for 2014 and 2013, along with the 5-year average, is shown in **Table S5.3**. It compares the number of vertical or directional wells with the number of horizontal wells drilled in the province and breaks down the number of new gas wells placed on production versus wells recompleted in existing wellbores and placed on production. In 2014, about 12.6 per cent of gas wells were recompletions into existing wellbores.

The number of new vertical wells placed on production increased in 2014, growing by 41.6 per cent over 2013 values. However, this number is still well off of the 5-year average, illustrating the shift by industry to horizontal drilling. The number of new horizontal wells placed on production in 2014 increased by 62.6 per cent year over year.

The number of natural gas horizontal wells using multistage fracturing technology is also increasing as a percentage of the total horizontal wells in the province. In 2014, about 96.4 per cent of horizontal wells were completed with multistage fracturing technology, compared with 95.4 per cent in 2013. This represents a significant increase when compared to the percentage of natural gas horizontal wells using multistage fracturing technology in 2008, which was about 28.6 per cent.

Activity increased by 27.1 per cent in PSAC Area 3 as producers took advantage of higher gas prices by drilling lower cost shallow vertical gas wells. However, despite the increase in activity, PSAC Area 3 still only represented 21.5 per cent of total activity in 2014, down from 24.2 per cent in 2013.

[4] Drain Well: In a multileg well where more than one leg is open to the same pool, legs other than the main production contributor are called drain wells.

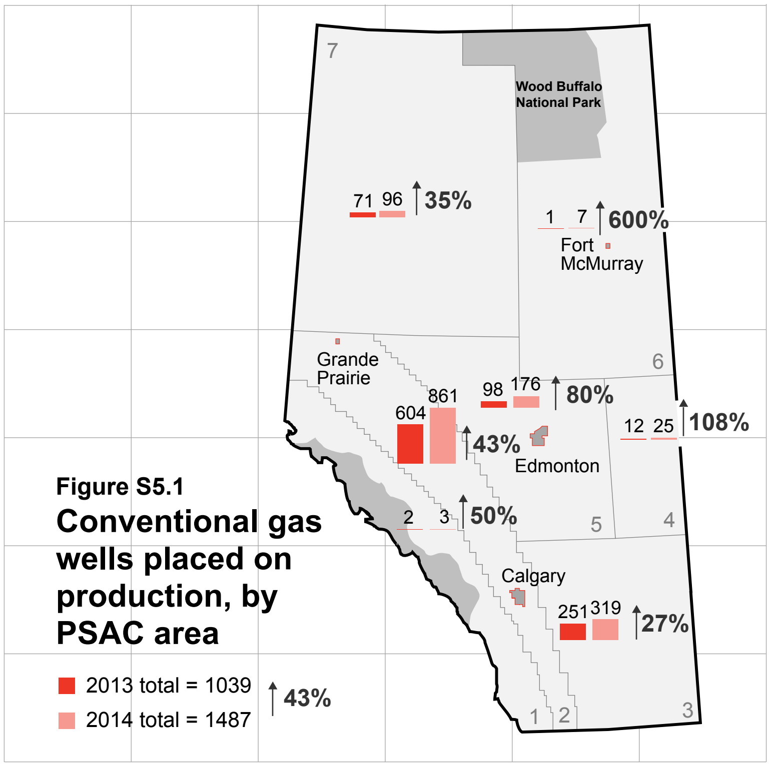


Figure S5.1
Conventional gas wells placed on production, by PSAC area

Table S5.3 Conventional gas wells placed on production by well type

	New wells placed on production			Recompletions			Total		
Well type	**2014**	**2013**	**5-year average**	**2014**	**2013**	**5-year average**	**2014**	**2013**	**5-year average**
Vertical/directional wells	344	243	762	152	171	351	496	414	1 113
Horizontal wells	956	588	664	35	37	23	991	625	687
Total	**1 300**	**831**	**1 426**	**187**	**208**	**374**	**1 487**	**1 039**	**1 800**

Activity in PSAC Area 2 remained strong in 2014, accounting for 57.9 per cent of total activity. This is consistent with 2013, which saw PSAC Area 2 account for 58.1 per cent of total activity. It is also well above the 39.7 per cent activity levels seen in the area in 2011. The number of horizontal wells placed on production in PSAC Area 2 increased by 57.6 per cent in 2014, whereas the number of vertical natural gas wells placed on production decreased by 37.9 per cent.

5.2.2.2 Production Trends

Figure S5.2 illustrates historical conventional marketable gas average daily production, including gas from oil wells, by PSAC area. With the exception of production from PSAC Area 2 and gas from oil wells, which increased by 8.9 per cent and 9.5 per cent, respectively, production in all areas of the province decreased in 2014. PSAC Areas 2, 3, and 7 remain the top-producing areas in the province, responsible for approximately 46.0 per cent, 12.1 per cent, and 9.9 per cent of production, respectively.

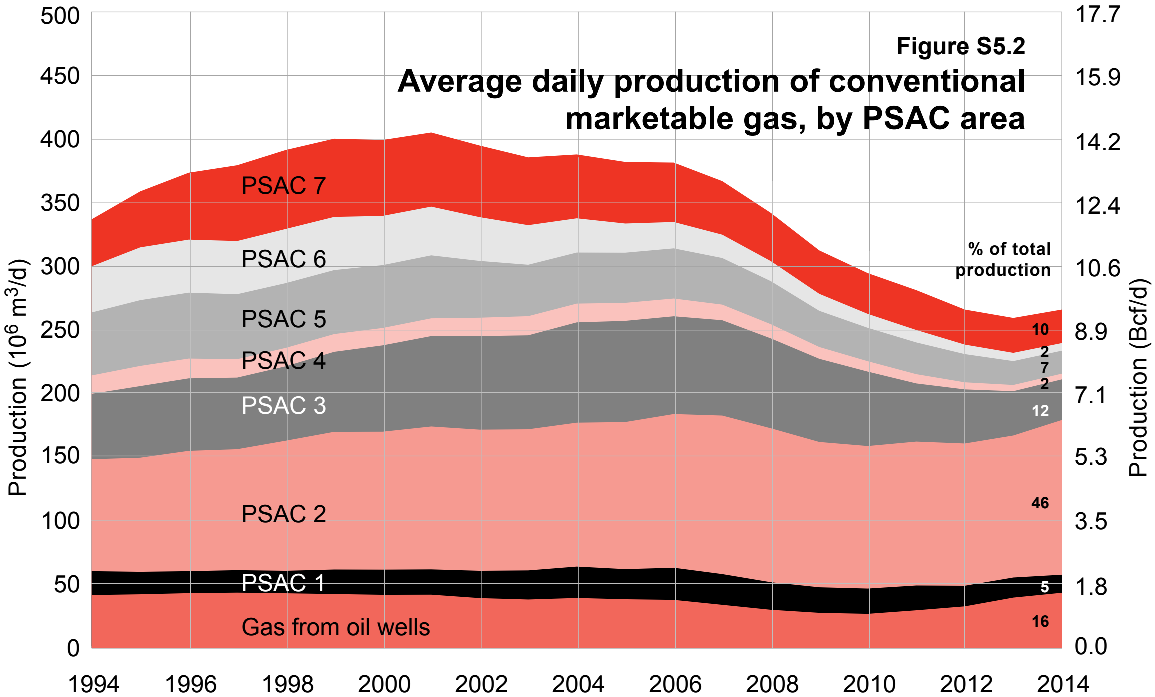


Figure S5.2
Average daily production of conventional marketable gas, by PSAC area

Figure S5.3 shows that from 1993 to 2009, while the total number of producing conventional gas wells increased, average daily gas production decreased after reaching its peak in 2001 as the number of new conventional gas wells each year was insufficient to offset production declines in existing gas wells. The first year in recent history in which the number of producing conventional gas wells dropped over the previous year was in 2009, this trend continued in 2014. In 2014, the number of producing conventional gas wells declined to 104 046 after reaching a high of 114 038 in 2008.

Historical conventional raw gas average daily production by year the well was placed on production is presented in **Figure S5.4**. Natural gas production from oil wells has continued to increase for the third year in a row, following the upward trend in Alberta's crude oil production. The percentages on the right-hand side of the figure represent each year's share of total production in 2014. About 13.2 per cent of conventional gas production in 2014 came from wells placed on production in 2014. Wells placed on production before 2004 contributed approximately 33.0 per cent.

Figure S5.5 compares total raw natural gas production in Alberta with both Texas and Louisiana onshore production and total U.S. gas production over the past 50 years. Both Texas and Louisiana show peak gas production in the late 1960s and early 1970s, while Alberta's production has a noticeably flatter production profile, peaking in 2001. For both Texas and Louisiana, gas production declined somewhat steeply after reaching peak production, but after a decade of decline, production rates stabilized. Only recently have they seen an increase in gas production because of the growth in shale gas, although Louisiana appears to be again in decline, following a peak in 2011.

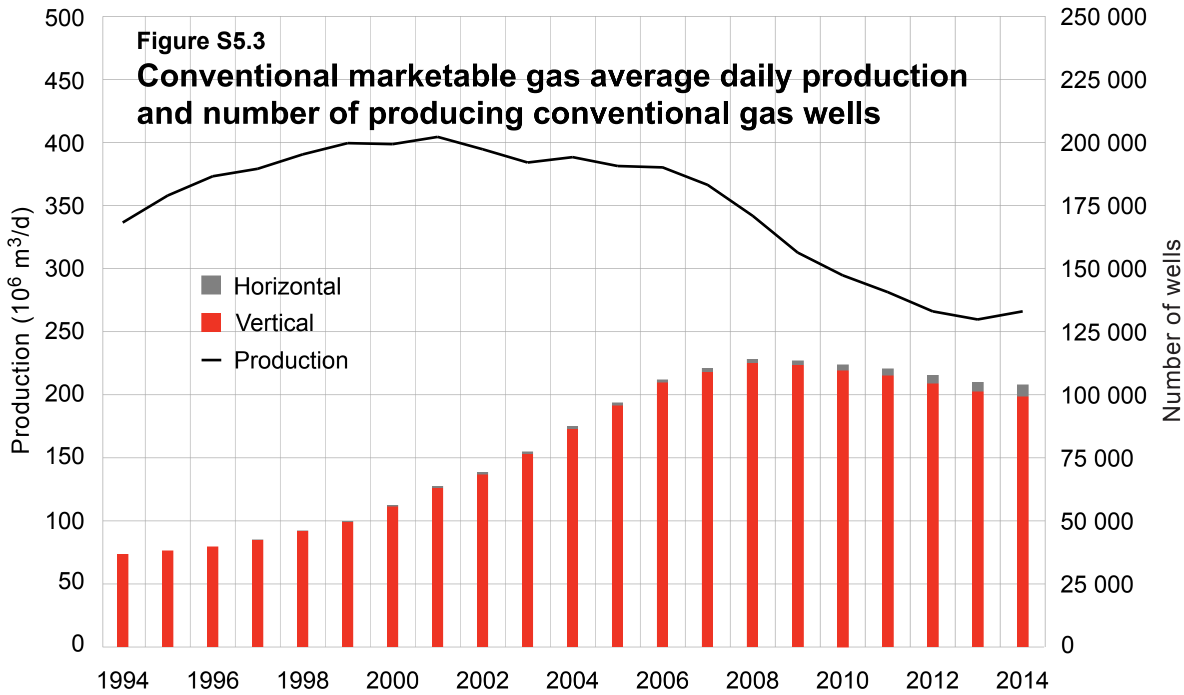


Figure S5.3
Conventional marketable gas average daily production and number of producing conventional gas wells

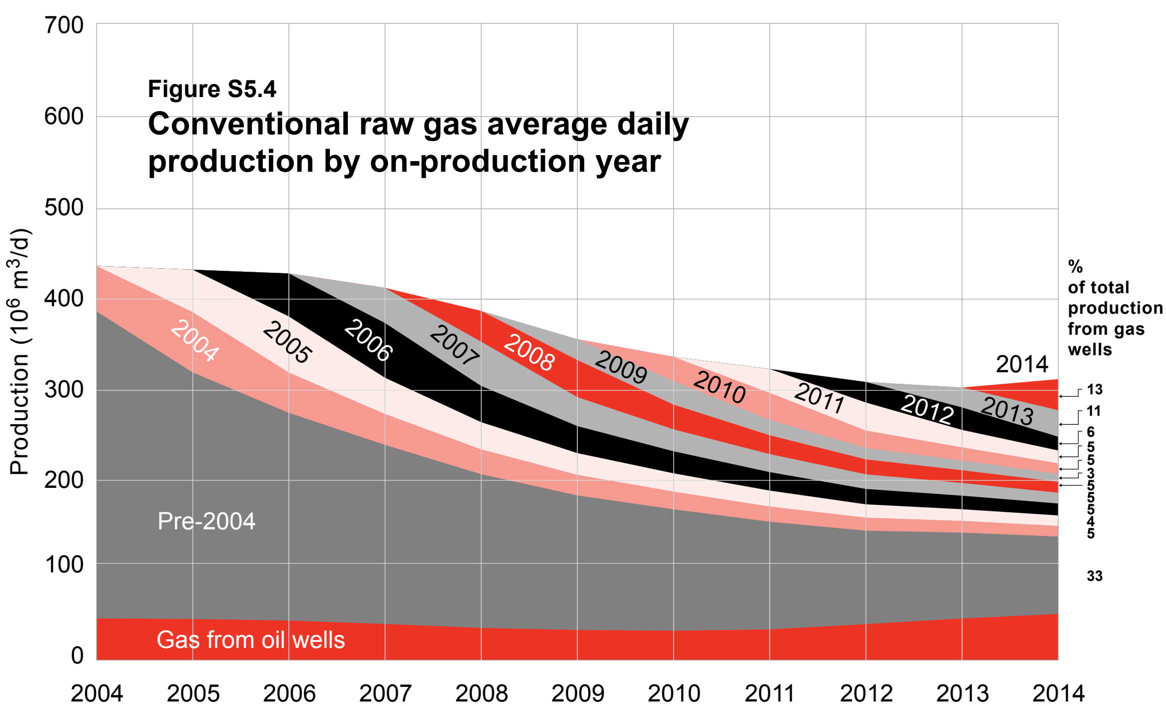


Figure S5.4
Conventional raw gas average daily production by on-production year

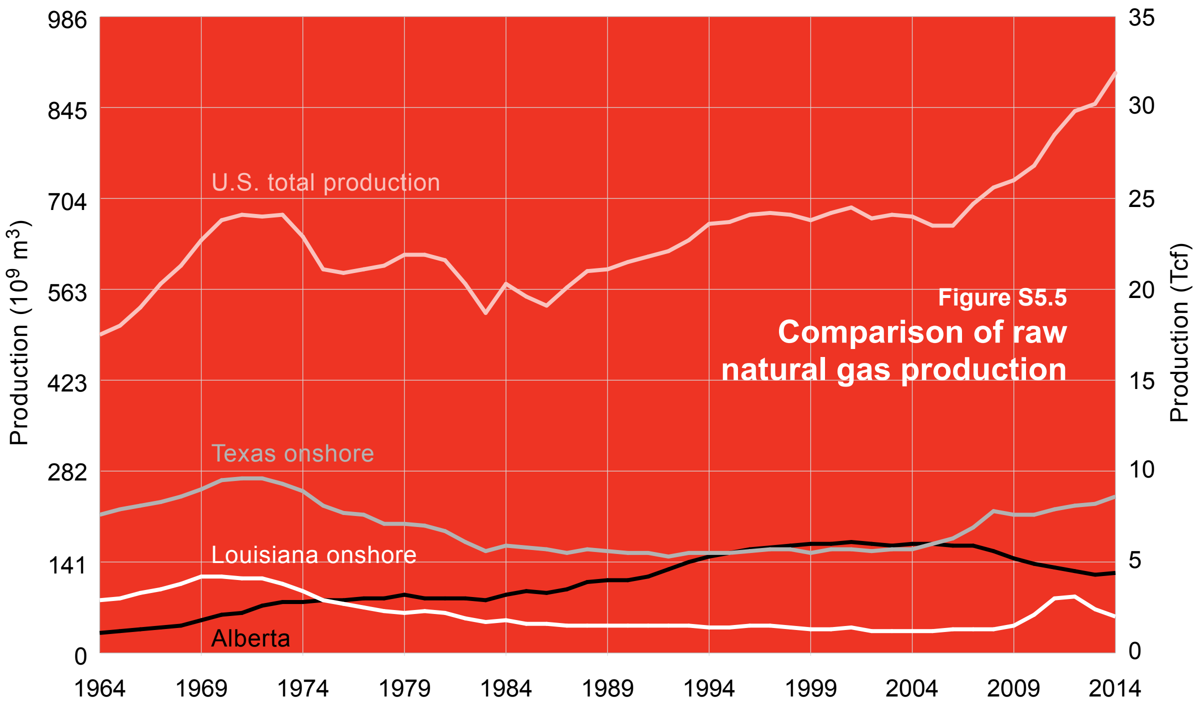


Figure S5.5
Comparison of raw natural gas production

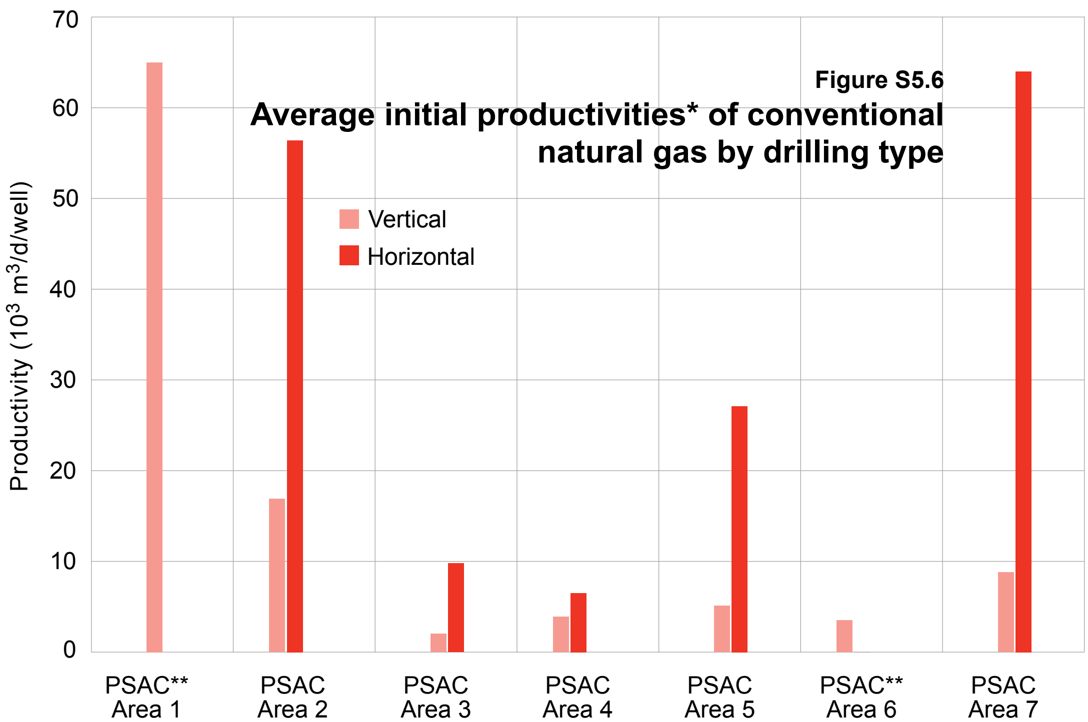
5.2.2.3 Production Characteristics of Conventional Natural Gas Wells

Starting with this report, the AER has revised its method of calculating initial productivity rates. In the past, the AER has used the first full calendar year of production to calculate initial productivity. The AER now uses the first 12 months of production for the well. These normalized initial productivities have been calculated for the average of the latest three years and the average of the last five years, with the three-year average presented in this report.

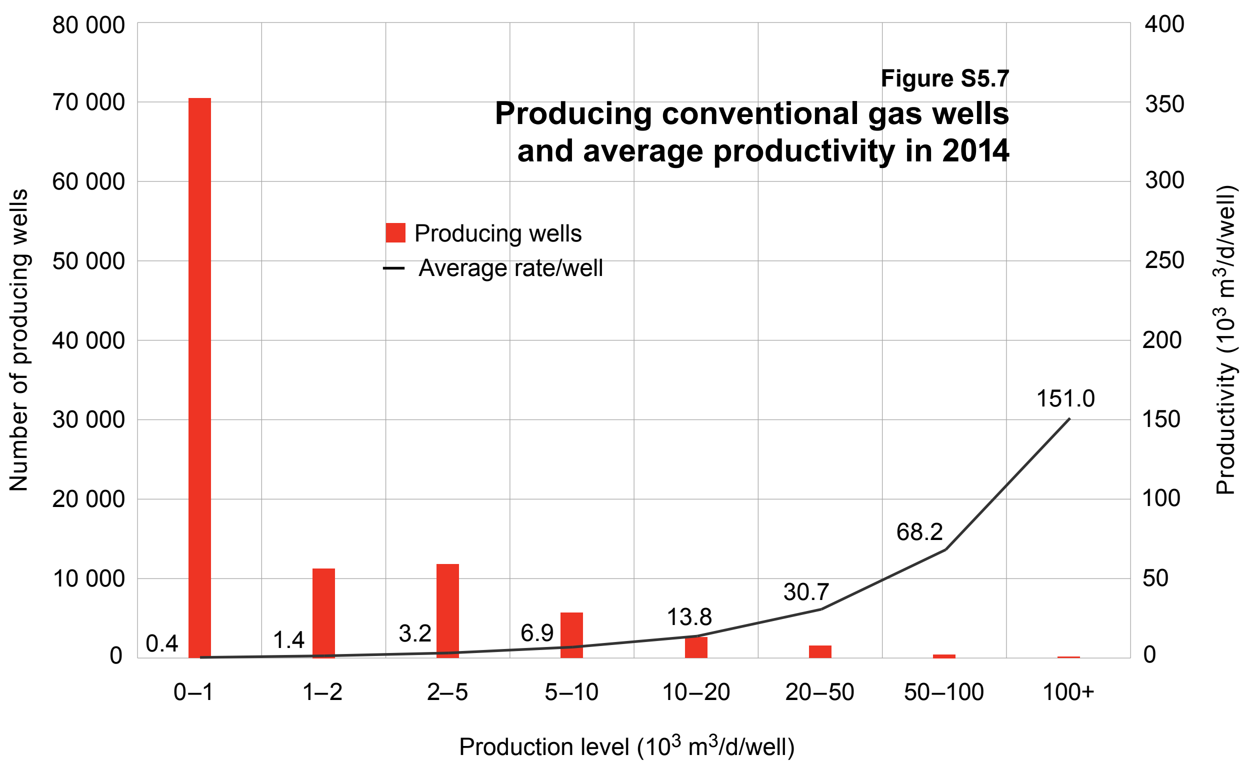
Average initial productivity of new producing conventional gas wells varies throughout the province and differs between vertical and horizontal well types. On average, horizontal wells have higher initial productivity rates than vertical wells, especially if completed with multistage fracturing. The average initial productivity rate over the last three years for Alberta was 22.1 10^3 m^3/d, very similar to the average for the last five years, as higher initial productivities in some areas have been balanced by lower initial productivities in others.

Figure S5.6 shows the three year average initial well productivity by well type for each PSAC area. As is shown in the chart, horizontal drilling and multistage fracturing technology increases the initial well productivity for PSAC Areas 2, 5, and 7. Limited information was available for horizontal wells in PSAC Areas 1 and 6; no reliable initial well productivity calculation could be made as a result.

Figure S5.7 charts the number of producing gas wells by range of average daily productivity in 2014. About 67.8 per cent of producing gas wells (70 491) produced less than 1.0 10^3 m^3/d of raw gas. These gas wells produced at an average rate of 0.4 10^3 m^3/d and contributed less than 10 per cent of the total conventional natural gas production.



* Adjusted for surface loss.
** Limited data available.



Less than 1 per cent of the conventional gas wells placed on production produced at rates over 50 10^3 m^3/d; however, they contributed about 21.4 per cent of total production. This is a significant change from 17.3 per cent of total production in 2013, illustrating the impact of multistage fracturing completion methods in horizontal drilling and the high productivity rates it achieves.

5.2.3 Coalbed Methane

The AER identifies CBM and CBM hybrid wells using licensing data, production reporting, and detailed geological evaluations. All wells placed on production and volumes in this section are based on CBM well designations as of December 31, 2014.

5.2.3.1 Coalbed Methane Wells Placed on Production

New CBM and CBM hybrid producing well activity for 2014 and 2013, in addition to a five-year average is shown in **Table S5.4**. The table shows the number of new and recompleted CBM and CBM hybrid wells placed on production in vertical or directional wells and horizontal wells within the AER-defined CBM play areas.

In 2014, there were 44 new CBM and CBM hybrid wells placed on production, with the majority located in the Horseshoe Canyon play area and all were vertical wells. No new wells have been placed on production in the Mannville play area in 2014. Overall, new CBM and CBM hybrid wells placed on production decreased by 40.5 per cent in 2014 over 2013.

In 2014, about 57.5 per cent of the CBM and CBM hybrid wells placed on production were recompletions into existing vertical wells, higher than the 53.8 per cent recompleted in 2013. Producers are recompleting more wells due to the lower capital cost and faster production schedule versus drilling a new well and placing it on production.

5.2.3.2 Coalbed Methane Production Trends

Total CBM and CBM hybrid average daily gas production and numbers of producing wells are shown in **Figure S5.8**. Of the 909 producing wells in the Mannville Group, 92.0 per cent are horizontal wells, while the opposite is true in the Horseshoe Canyon play area, where less than 1 per cent of the 19 751 producing wells are horizontal.

5.2.3.3 Production Characteristics of Coalbed Methane Wells

The three-year average initial daily productivity rate in the Horseshoe Canyon play area was 1.3 10^3 m^3/d, up from the five-year average of 1.2 10^3 m^3/d as a result of producers targeting more productive wells. Due to a lack of drilling and completion activity in the Mannville Group, no reliable average productivity rates could be calculated.

Table S5.4 CBM and CBM hybrid wells placed on production by well type and CBM play area

	New wells placed on production			Recompletions			Total		
CBM play area	**2014**	**2013**	**5-year average**	**2014**	**2013**	**5-year average**	**2014**	**2013**	**5-year average**
Vertical/directional wells									
Horseshoe Canyon	40	63	358	50	58	151	90	121	509
Mannville	0	0	0	0	0	0	0	0	0
Undefined[a]	4	11	44	11	28	42	15	39	86
Subtotal	**44**	**74**	**402**	**61**	**86**	**193**	**105**	**160**	**595**
Horizontal wells									
Horseshoe Canyon	0	0	1	1	0	1	1	0	2
Mannville	0	0	6	0	0	0	0	0	6
Undefined[a]	0	0	1	0	0	0	0	0	1
Subtotal	**0**	**0**	**7**	**1**	**0**	**1**	**1**	**0**	**8**
Total	**44**	**74**	**409**	**62**	**86**	**194**	**106**	**160**	**603**

[a] Includes wells placed on production outside defined play subarea boundaries.

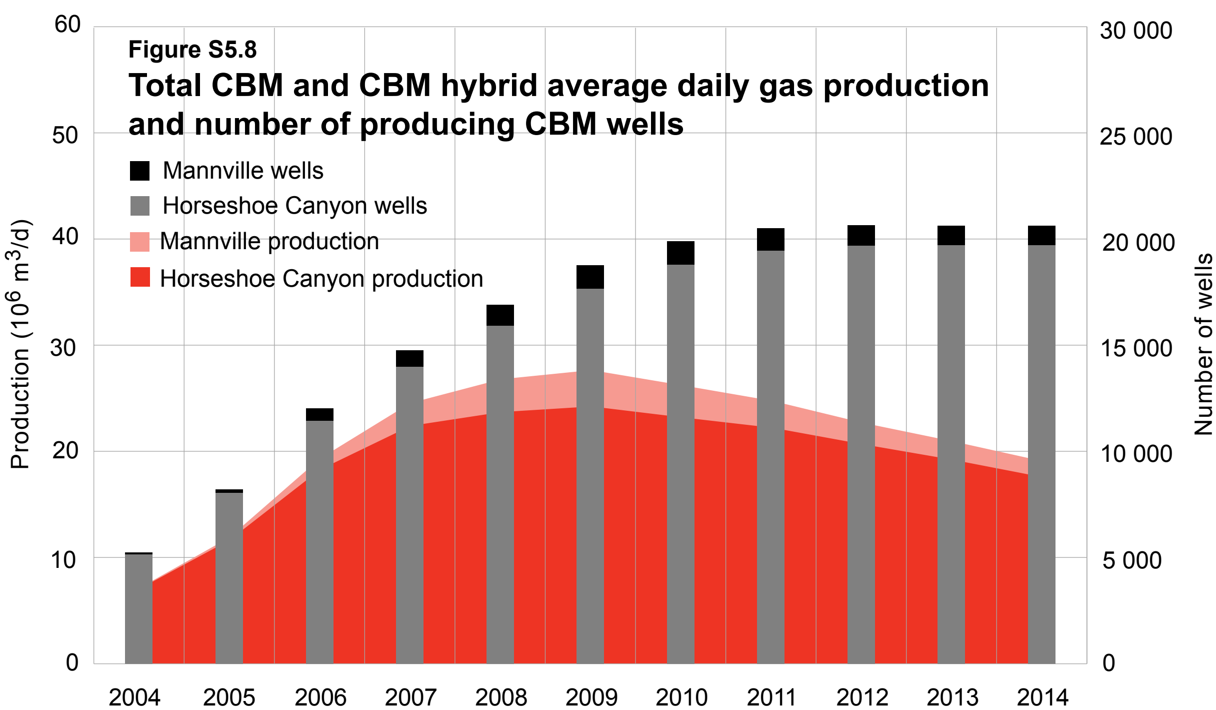


Figure S5.8
Total CBM and CBM hybrid average daily gas production and number of producing CBM wells

5.2.4 Shale Gas

The AER identifies shale gas wells placed on production using the designation submitted by the operator to Petrinex.[5] If required, these designations are evaluated and adjusted based on new information, resulting in revisions to historical annual numbers. All shale gas wells placed on production and volumes in this section are based on current well designations as of December 31, 2014.

5.2.4.1 Shale Gas Wells Placed on Production

As the shale industry in Alberta is still in its infancy, the data continues to be revised on an annual basis as the AER reviews well data.

The AER currently recognizes 238 producing shale wells in 2014, including commingled wells that contain two or more completions with at least one in a recognized shale formation. Horizontal gas wells drilled in low permeability gas-bearing formations in northwest Alberta are reported as conventional gas, and reserves associated with this development are included in the conventional gas category in this report; however, as the play extends into British Columbia, it becomes generally shalier and is recognized as shale gas.

Shale gas average daily production in Alberta is shown in **Figure S5.9** along with the number of producing shale gas wells placed on production in each year. **Table S5.5** identifies the type of new shale wells placed on production in 2014 and 2013, in addition to the five-year average. The number of shale gas wells placed on production continues to grow, with 89 wells added in 2014, an increase of 23.6 per cent over 2013.

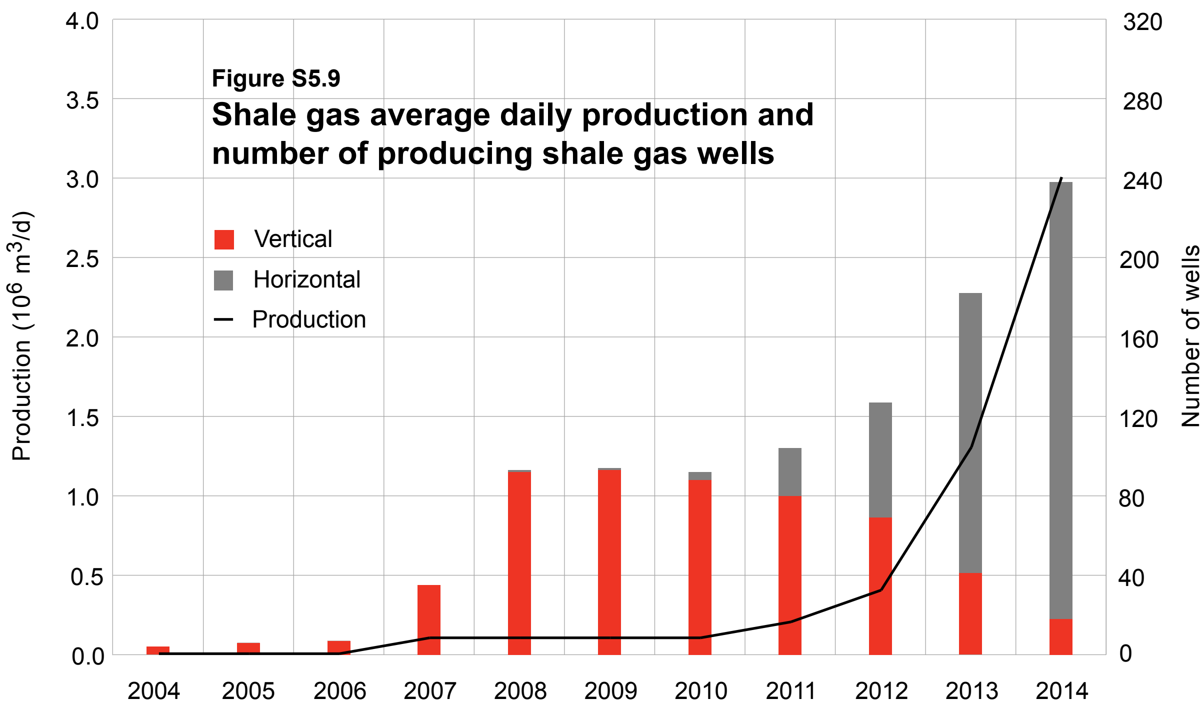
Table S5.5 Shale gas wells placed on production by well type

	New wells placed on production			Recompletions			Total		
Well type	**2014**	**2013**	**5-year average**	**2014**	**2013**	**5-year average**	**2014**	**2013**	**5-year average**
Vertical/directional wells	0	0	0	0	3	2	0	3	2
Horizontal wells	82	66	42	7	3	2	89	69	44
Total	**82**	**66**	**42**	**7**	**6**	**4**	**89**	**72**	**46**

5.2.4.2 Shale Gas Production Trends

PSAC Area 2 continues to lead shale activity, with 86.5 per cent of wells placed on production in 2014 occurring in the area. This is up from 77.8 per cent of wells placed on production in 2013. PSAC Area 2 is also responsible for the majority of reported shale production, with this area responsible for about 92.3 per cent of total shale gas production in the province. The majority of producing shale wells in PSAC Area 2 have been completed in the Woodbend Group, which includes the Duvernay among other zones. The three-year average initial daily productivity rate for producing wells was 15.8 10^3 m^3/d, slightly higher than the five-year average of 14.1 10^3 m^3/d.

[5] Petrinex is a secure, centralized information network facilitating the exchange of petroleum related information. It allows producers in Alberta to report, manage, and exchange up-to-date volumetric, royalty and commercial information with government and members of industry accurately and efficiently.



5.2.5 Supply Costs

Table S5.6 summarizes the estimated costs for conventional and CBM natural gas from selected areas in Alberta based on 2014 estimated costs and production profiles. The supply costs are based on representative wells in each PSAC area. Supply costs for different geological plays and PSAC areas vary significantly because of differing production rates, well types, drilling and operating costs, royalties, and other factors. Therefore, the results may not be reflective of wells that differ from the representative well profiles used in the analysis.

The supply cost estimate for an average horizontal or vertical well in each PSAC area includes the following data: initial productivities, production decline rates, vertical drilled depths and total measured depths of the wells, gas composition, shrinkage, capital cost, operating costs, royalties and taxes, and a 10 per cent nominal rate of return. The supply costs in **Table S5.6** are not risked (i.e., assumes a 100 per cent success rate). Supply costs are estimated as plant-gate costs, which are reported in Canadian dollars (Cdn$). The representative wells in PSAC Areas 1, 2, 5, and 7 are assumed to have wet gas.

The table shows that results between horizontal wells and vertical wells vary considerably across the areas, illustrating the importance of understanding the underlying geology and employing the appropriate technology. **Table S5.6** shows that wells that target wet gas typically have lower supply costs as the presence of liquids provides value uptick and helps offset the costs of the well. In addition, **Table S5.6** shows that wells with longer total measured depths, typically horizontal wells, are associated not only with higher initial productivities but also with higher capital costs. To the extent that the higher initial productivities are able to offset the higher capital costs, such as in PSAC Areas 2 and 7, these wells are associated with lower supply costs. However, the higher capital costs are not offset for all horizontal drilling, such as the representative well in PSAC Area 5. Each of

Table S5.6 Natural gas supply costs for PSAC areas and CBM play areas[a]

Area	Formation	Type of well	Type of gas	Total measured depth (m)	Initial productivity (10^3 m^3/d)	Total capital cost (Cdn$000)	Variable operating cost (Cdn$/$10^3$ m^3)	Natural gas supply cost (Cdn$/GJ)
PSAC 1	Wabamun	Directional	Sour	4 500	76.8	19 558	53.24	5.05
PSAC 2	Shunda	Vertical	Sweet	3 000	19.5	3 302	56.80	5.05
PSAC 2	Cardium	Horizontal	Sweet	4 200	52.9	4 721	56.80	3.26
PSAC 3	2nd Specks	Vertical	Sweet	560	2.5	614	49.69	8.40
PSAC 4	Colony SS	Vertical	Sweet	900	3.0	998	30.17	10.28
PSAC 5	Mannville	Vertical	Sweet	1 150	6.3	1 309	31.90	4.58
PSAC 5	Duvernay	Horizontal	Sweet	5 000	27.1	6 901	31.90	7.38
PSAC 6	Grand Rapids	Vertical	Sweet	600	8.1	775	35.50	4.37
PSAC 7	Kiskatinaw	Vertical	Sweet	2 300	16.0	2 756	30.20	4.04
PSAC 7	Montney	Horizontal	Sweet	3 500	56.8	8 254	30.20	4.59
CBM-HSC[b]	Horseshoe Canyon	Vertical	CBM	250	1.2	759	40.80	12.85
CBM-MAN[c]	Mannville	Horizontal	CBM	2 400	5.3	2 039	31.90	12.55

[a] Cost data from petroCUBE, and PSAC's 2015 *Well Cost Study* (published in October 2014) has been used to estimate the supply costs in PSAC areas.

[b] Horseshoe Canyon.

[c] Mannville Corbett.

the representative wells are assumed to have only one lateral, creating an upward bias on supply costs estimates. Multiwell pads and multilateral wells would incur marginal capital costs for additional legs, while gained production efficiencies would reduce average supply costs relative to single-lateral wells. Further, the AER has not considered recompletions in the analysis, which are performed at substantially lower costs than a new drill although initial productivities are not as high.

With the AECO-C daily natural gas price in 2014 averaging Cdn$4.21/GJ, certain plays proved to be economic, particularly in the "wetter" areas of the province. This is evidenced by the increase in activity in PSAC Areas 2, 5, and 7, although all areas saw an increase in activity in early 2014 as a result of increased natural gas prices. The recent low-price environment has impacted the supply costs estimated as reduced liquids prices did not offset the costs as much as it has in previous years. However, given the continued drilling in PSAC Areas 2, 5, and 7 over the latter half of 2014 and into early 2015, it would appear that demand for natural gas liquids, and specifically condensate, from oil sands diluent requirements, has provided support for continued drilling. Lower prices are likely to influence drilling decisions and improve costs efficiencies moving forward. As these gains are realized, the economics for the representative wells will improve and supply costs will decline.

5.2.6 Marketable Natural Gas Production – Forecast

In projecting conventional gas and CBM supply, the AER considers three components: expected production from existing conventional gas and CBM wells placed on production, expected production from new conventional gas and CBM wells placed on production in new and existing wells through recompletions, and gas production from oil wells. The AER also takes into account its estimates of the remaining established and yet-to-be-established reserves of conventional natural gas in the province. Since shale gas development is in its early stages in Alberta, the AER does not have sufficient information to confidently forecast shale gas supply at this time.

To forecast gas production, production data from existing wells and from new wells drilled and placed on production each year have been analyzed. The number of new wells placed on production and the average productivity for the wells are the main determining factors used in projecting natural gas production volumes over the forecast period.

5.2.6.1 Conventional Gas

To project natural gas production from existing producing conventional gas wells, the AER assumes the following:

- Decline rates for gas production from existing conventional gas wells placed on production at year-end 2014 vary depending on factors such as the age, type, and geological and geographical locations of the wells. Overall it is assumed that rates will decline by 12.8 per cent per year over the forecast period based on observed performance. This is slightly higher than last year's forecast of a 12.0 per cent annual decline.

- Production from existing conventional gas wells placed on production will average 201.3 10^6 m^3/d in 2015 and decline to 59.7 10^6 m^3/d in 2024.

To project natural gas production from new conventional gas wells placed on production, the AER assumes the following:

- The AER has predicted initial productivity for those wells expected to be placed on production within the forecast period by year and PSAC area. Within PSAC Areas 2, 5, and 7, a separate forecast was made for vertical and horizontal wells. Initial productivity for 2015 will vary widely, ranging from between 2.8 10^3 m^3/d in PSAC Area 3 to 51.7 10^3 m^3/d in PSAC Area 1.

- The AER also predicted decline rates for those wells expected to be placed on production within the forecast period by year and PSAC area. Within PSAC Areas 2, 5, and 7, a separate forecast was made for vertical and horizontal wells. Decline rates for 2015 will vary between 28 per cent in PSAC Area 1 to 47 per cent in PSAC Area 5 for horizontal wells. Decline rates by the end of the forecast period in 2024 will range from between 8 per cent in PSAC Area 1 to 13 per cent in PSAC Area 4.

- Based on historical data, production from gas wells over the forecast period, although variable, will generally decline by approximately 37 per cent in the first year, 25 per cent in the second year, 19 per cent in the third year, and 17 per cent in the fourth year. The decline rate will then continue to decrease gradually every year before reaching 10 per cent in the tenth year.

- The number of conventional gas wells placed on production over the forecast period is projected to start at 1155 in 2015 and increase to 1752 by 2024. The number of forecast wells placed on production is lower than last year's forecast of 1214 in 2015 and 1939 by 2023.
- The AER also predicted the number of wells expected to be placed on production within the forecast period by year and PSAC area. Within PSAC Areas 2, 5, and 7, a separate forecast was made for vertical and horizontal wells.
- Conventional gas wells placed on production in PSAC Area 3 will represent 20.9 per cent of all new conventional gas wells placed on production in 2015, which will gradually increase to 23.5 per cent in 2024. The relative stability of production from PSAC Area 3 reflects the assumption that over the forecast period, the AER expects that the shift in new wells from the dry gas of PSAC Area 3 to the wet gas of PSAC Areas 2, 5, and 7 will continue as gas producers see higher returns from gas with liquids.
- The AER expects that PSAC Areas 2, 5, and 7 will represent 75.8 per cent of all conventional wells placed on production in 2015, before decreasing to 66.3 per cent by 2024. Horizontal wells are projected to represent about 86.1 per cent of the new wells placed on production in these PSAC areas in 2015, declining slightly to just over 80.6 per cent by 2024.

To project natural gas production from oil wells, the AER assumes the following:

- Gas production from oil wells, based on observed performance, will average 41.7 10^3 m^3/d in 2015, and will gradually decrease to 30.8 10^3 m^3/d by 2024. This forecast is based on the AER's crude oil forecast and assumes that gas production from oil wells follows the historical trend.

Based on the remaining established and yet-to-be-established reserves, and the assumptions described above, the AER forecasts conventional marketable gas production to decrease from 265.2 10^6 m^3/d in 2014 to 260.0 in 2015, before falling to 238.2 10^6 m^3/d in 2024. This compares to last year's forecast of 228.4 10^6 m^3/d in 2023. If conventional natural gas production rates follow the projection, Alberta will have recovered 84.7 per cent of the 6528 10^9 m^3 ultimate potential by 2024.

5.2.6.2 Coalbed Methane

In projecting CBM supply, the AER considers expected production from existing producing CBM wells and estimated production from new CBM wells placed on production. These new CBM wells placed on production include CBM wells placed on production from new wells drilled and from recompletions into existing non-CBM wells. Continual reclassification of CBM wells placed on production results in revisions to historical data and, therefore, changes to annual forecasts.

To forecast production from new CBM and CBM hybrid wells placed on production, the AER assumed the following:

- Over the forecast period, it was assumed that the majority of new CBM and CBM hybrid production will be from the Horseshoe Canyon play area.
- The average initial productivity of a new CBM well in the Horseshoe Canyon play area will be 1.2 10^3 m^3/d and gradually decrease to 0.8 10^3 m^3/d by 2024.
- The number of CBM and CBM hybrid wells placed on production is forecast to be 75 in 2015 and will increase to 135 by 2024. This forecast has decreased substantially from last year's projection due to the continuing low levels of activity reported in 2014 and the expectation that return on investment will not significantly improve over the forecast period because of the forecast gas prices.

Production from CBM wells placed on production, which includes commingled production from conventional gas formations, is expected to be 12.0 10^6 m^3/d in 2024, relatively unchanged from last year's forecast as the majority of production is expected to come from previously existing wells. In 2014, CBM production contributed 6.6 per cent of the total Alberta marketable gas production, similar to that of the previous year, and is projected to contribute 4.8 per cent of the total Alberta marketable gas production in 2024, which is down from last year's forecast largely as a result of increased production from conventional natural gas.

5.2.6.3 Shale Gas

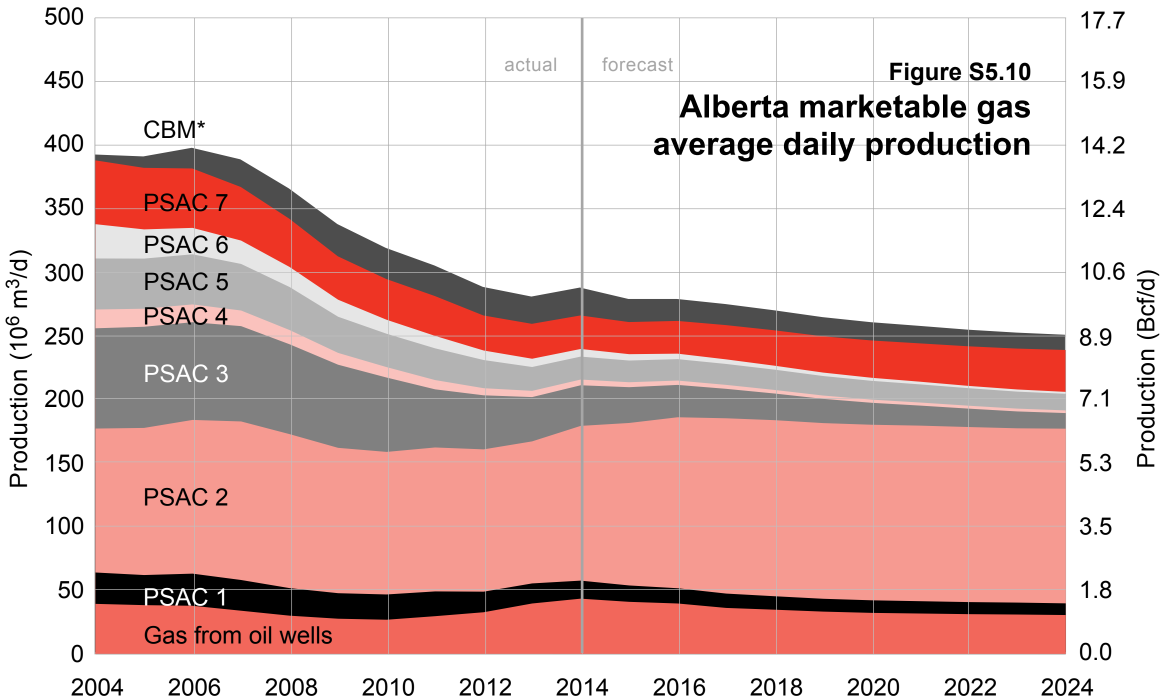
As mentioned earlier, the AER does not currently have sufficient information to confidently forecast shale gas supply at this time. However, the extent of the economic viability of shale development in Alberta is becoming clearer. Commercial shale gas production remains in its infancy, and it will still take some time to establish how producible the resource is over the long term.

5.2.6.4 Total Gas Production

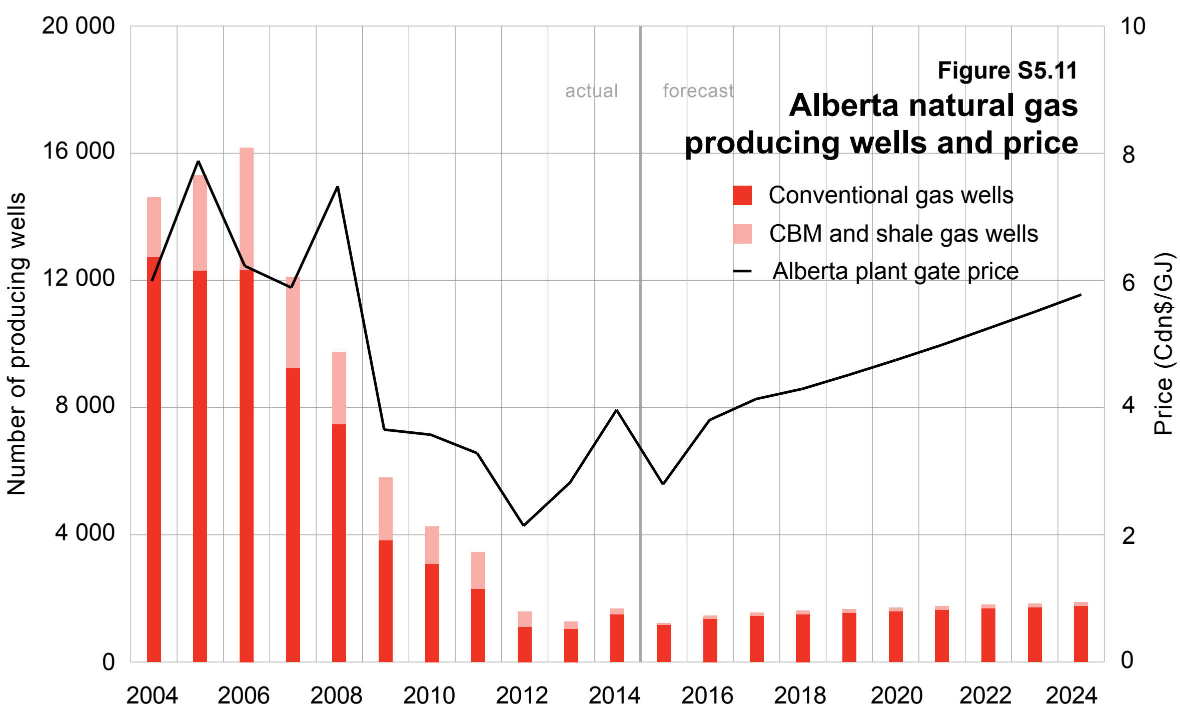
The AER's forecast of average daily production from conventional gas wells in each PSAC area, conventional oil wells, and production from CBM wells are shown in **Figure S5.10**. The AER forecasts that total marketable gas production will decline from 278.7 10^6 m^3/d in 2015 to 250.2 10^6 m^3/d in 2024. This is slightly higher than last year's forecast of 242.5 10^6 m^3/d in 2023 because of continued liquids focused drilling using horizontal multistage fracturing completion techniques.

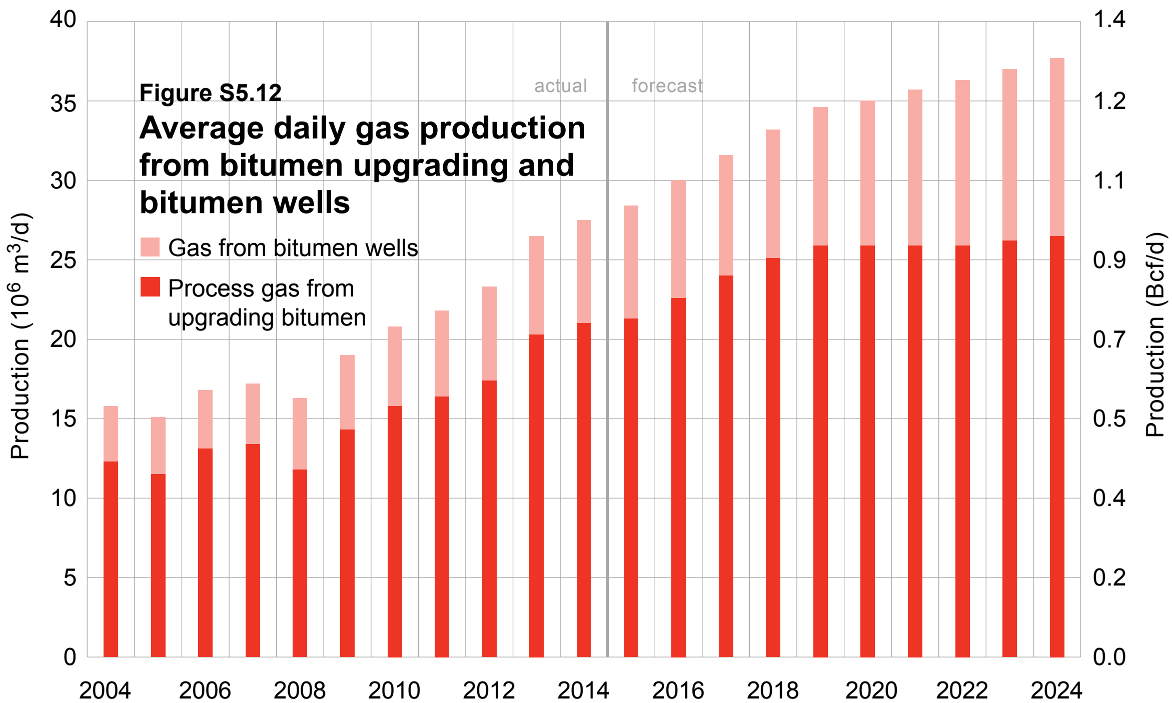
Figure S5.11 illustrates historical new wells placed on production for conventional, CBM, and shale gas wells, with a forecast for conventional and CBM wells, along with plant gate gas prices (see **Section 1** for a discussion on price forecasts).

Figure S5.12 shows average daily process gas production (rich in liquids) from bitumen upgrading and raw natural gas from bitumen wells. Gas from these sources is used primarily as fuel in oil sands development.



*Actual includes minor shale gas.





In 2014, about 21.0 10^6 m^3/d of process gas was generated at oil sands upgrading facilities, compared with a revised volume of 20.3 10^6 m^3/d in 2013. Process gas is primarily used as fuel, although increasing volumes are being sent to processing facilities for the removal of liquids. Process gas volumes are expected to reach 26.5 10^6 m^3/d by the end of the forecast period. Natural gas production from primary and thermal bitumen wells increased by 0.2 10^6 m^3/d to 6.5 10^6 m^3/d in 2014 and is forecast to increase to 11.2 10^6 m^3/d by 2024. This gas is used primarily as fuel to create steam for on-site operations.

5.2.7 Commercial Natural Gas Storage

Commercial natural gas storage is used by the natural gas industry to provide short-term deliverability; the AER does not use volumes of commercially stored natural gas in projecting long-term production. Several pools in the province are being used for commercial natural gas storage as an efficient means of balancing supply with fluctuating market demand. There are other noncommercial gas storage schemes in the province that are not included in this category.

In the summer season, when demand is lower, natural gas is injected into these pools. As winter approaches and demand for natural gas rises, injection slows or ends, and storage withdrawals generally begin at high withdrawal rates. Commercial natural gas storage pools, along with the operators and storage information, are listed in **Table S5.7**.

In 2014, natural gas withdrawal for all storage schemes exceeded injections by 1283 10^6 m^3. This compares with 1463 10^6 m^3 net injection in 2013. Following a trend that began in November of 2013, storage levels continued to rapidly decrease to start 2014 as winter increased demand. The storage drawdown continued into March 2014, at

Table S5.7 Commercial natural gas storage pools as of December 31, 2014

Field	Pool	Operator	Storage capacity (10^6 m^3)	Injection volumes (10^6 m^3)	Withdrawal volumes (10^6 m^3)
Brazeau River	Nisku E	Wild Rose Energy Ltd.	940	0	0
Carbon	Glauconitic	ATCO Midstream	1 127	955	1 056
Carrot Creek	Cardium CCC	Iberdrola Canada Energy Services Ltd.	986	595	571
Countess	Bow Island N & Upper Mannville M5M	Niska Gas Storage	1 552	1 707	1 320
Crossfield East	Elkton A & D	CrossAlta Gas Storage	1 197	107	1 737
Dimsdale	Paddy A	Ranchwest Energy	2 377	0	0
Edson	Viking D	TransCanada Pipelines Ltd.	1 775	830	640
Hussar	Glauconitic R	Husky Oil Operations Ltd	423	319	392
McLeod	Cardium D	Iberdrola Canada Energy Services Ltd.	282	279	343
Suffield	Upper Mannville I & K, and Bow Island N & BB & GGG	Niska Gas Storage	2 254	1 996	1 697
Warwick	Glauconitic-Nisku A	Warwick Gas Storage Inc.	881	113	429
Total			**11 417**	**6 901**	**8 184**
Difference					**−1 283**

which point storage levels dropped below the five-year average. Withdrawals for the November 2013 to March 2014 period totalled 9320 10^6 m^3, compared to 4042 10^6 m^3 in 2013, due to the freezing temperatures that affected parts of Manitoba, Ontario, Quebec, the Atlantic provinces, and the eastern United States, that dramatically increased the demand for natural gas for heating purposes. Inventories continued to build throughout the summer and early fall, although storage levels remained below the five-year average entering the 2014/15 heating season.

Marketable gas production volumes determined for 2014 were adjusted to account for the imbalance between volumes injected and volumes withdrawn from these storage pools. For the purpose of projecting future natural gas production, the AER assumes that injections and withdrawals are balanced for each year during the forecast period.

Figure S5.13 shows the location of existing gas storage facilities along the pipeline systems within Alberta and indicates border points for gas removals from the province.

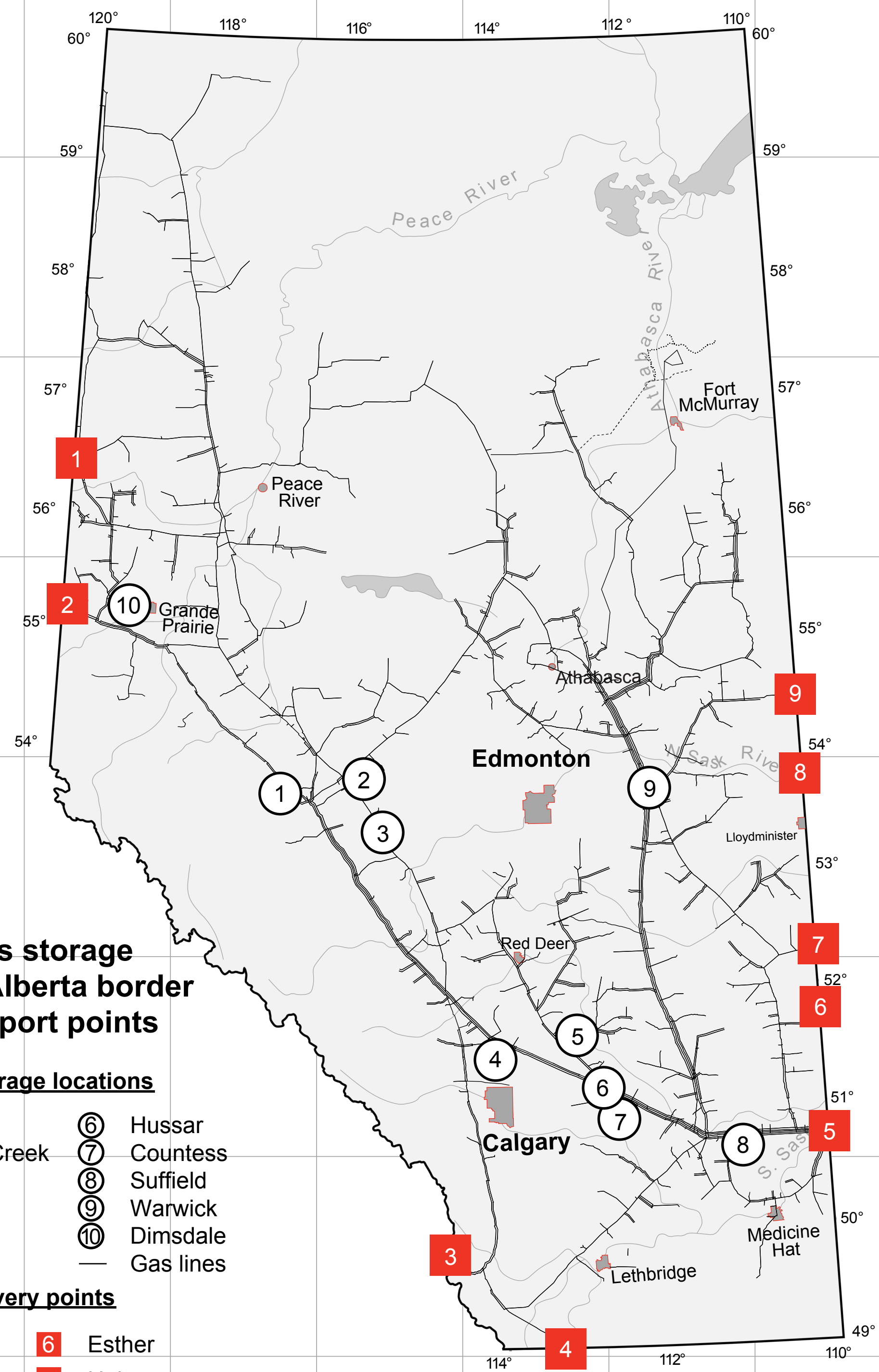


Figure S5.13
Commercial gas storage locations and Alberta border delivery and export points

Commercial gas storage locations

1	Edson	6	Hussar
2	McLeod/Carrot Creek	7	Countess
3	Brazeau River	8	Suffield
4	Crossfield	9	Warwick
5	Carbon	10	Dimsdale
		—	Gas lines

Pipeline border delivery points

1	Boundary Lake	6	Esther
2	Gordondale	7	Unity
3	Alberta/B.C.	8	Meridian Lake
4	Montana	9	Cold Lake
5	Empress/McNeill		

5.2.8 Alberta Natural Gas Demand

The *Alberta Gas Resources Preservation Act* (first proclaimed in 1949) provides supply security for consumers in Alberta by "setting aside" large volumes of gas for their use before gas removals from the province are permitted. The act requires that when a company proposes to remove gas from Alberta, it must apply to the AER for a permit authorizing the removal.

The calculation in **Table S5.8** is done annually to determine what volume of gas is available for removal from Alberta after accounting for Alberta's future requirements. Using the 2014 remaining established reserves number, surplus natural gas is currently calculated to be 346 10^9 m^3. **Figure S5.14** illustrates historical "available for permitting" volumes.

Gas removals from Alberta have declined since 2001, from 311.5 10^6 m^3/d in 2001 to 149.2 10^6 m^3/d in 2014. Based on the AER's projection of gas production, this rate is expected to drop to 63.7 10^6 m^3/d by 2024. This is higher than last year's projection of 53.8 10^6 m^3/d by 2023 due to an increase in the natural gas production forecast and a slight decline in Alberta demand because of a lower production forecast in the oil sands sector.

The major natural gas pipelines in Canada that move Alberta gas to market are discussed in **Section 9.1.1.3** and illustrated in **Figure 9.3.** Provincial border points are identified in **Figure S5.13** alongside commercial storage locations.

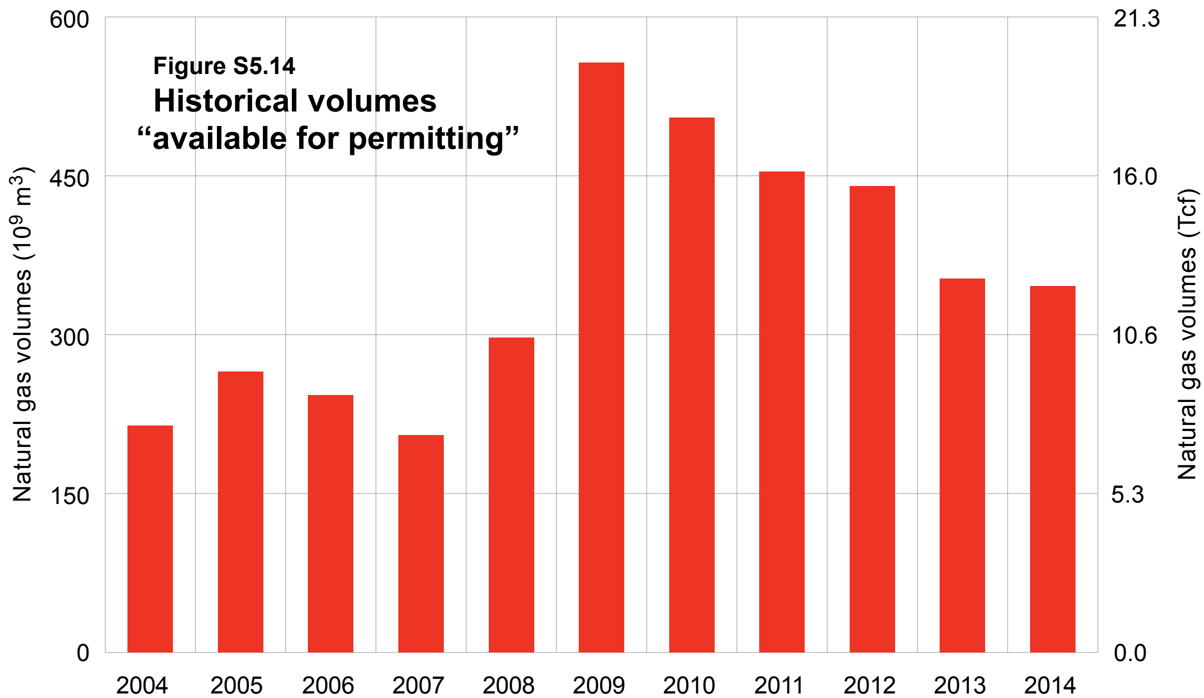
The AER forecasts projected total demand for Alberta natural gas by first forecasting intra-Alberta natural gas use. For Canadian ex-Alberta markets, historical demand growth and remaining forecast supply (net of intra-Alberta demand) are used in developing the demand forecasts. Export markets are forecast based on removal pipeline capacity available to serve such markets and on the recent historical trends in meeting that demand.

Table S5.8 Estimate of gas reserves available for inclusion in removal permits as of December 31, 2014

	10^9 m^3 at 37.4 MJ/m^3
Reserves (as of year-end 2014)	
1. Total remaining established reserves	865
Alberta requirements	
2. Core market requirements	121
3. Contracted for noncore markets[a]	168
4. Permit-related fuel and shrinkage	21
Permit requirements	
5. Remaining permit commitments[b]	209
6. Total requirements	519
Available	
7. Available for removal permits	346

[a] For these estimates, 15 years of core market requirements and 5 years of noncore requirements were used.

[b] The remaining permit commitments are split 99.5 per cent under short-term permits and 0.5 per cent under long-term permits.



Imports of natural gas from the United States remain at historically high levels, according to data from the Energy Information Administration (EIA). The increase in imports is being driven by increasing shale gas production in the United States, particularly in regions located close to eastern Canadian markets that had typically been served by western Canadian natural gas. This trend is expected to continue as production in the northeastern United States continues to expand, causing producers and pipeline companies to propose new pipeline projects that would carry natural gas sourced from the United States to Canadian markets. A summary of the proposed natural gas pipeline developments is available in **Table 9.9**.

Figure S5.15 illustrates the breakdown of marketable natural gas demand in Alberta by sector.

Residential gas requirements are expected to grow moderately at an average annual rate of 3.4 per cent over the forecast period based on population growth projections, although improvements in energy efficiency prevent household energy use from rising significantly.

Commercial gas demand in Alberta has declined gradually since 2003 and is expected to continue to decline at an average annual rate of 1.2 per cent per year over the forecast period. This is largely due to gains in energy efficiency and a shift towards electricity.

The electricity-generating industry will require increased volumes of natural gas to fuel new industrial on-site and gas-fired generation plants expected to come on stream over the forecast period. Natural gas requirements for electricity generation are expected to increase from about 22.5 10^6 m^3/d in 2014 to 35.2 10^6 m^3/d by 2024. The projected increase in gas demand in this sector is due to the assumption that gas will be the preferred feedstock for new power plants.

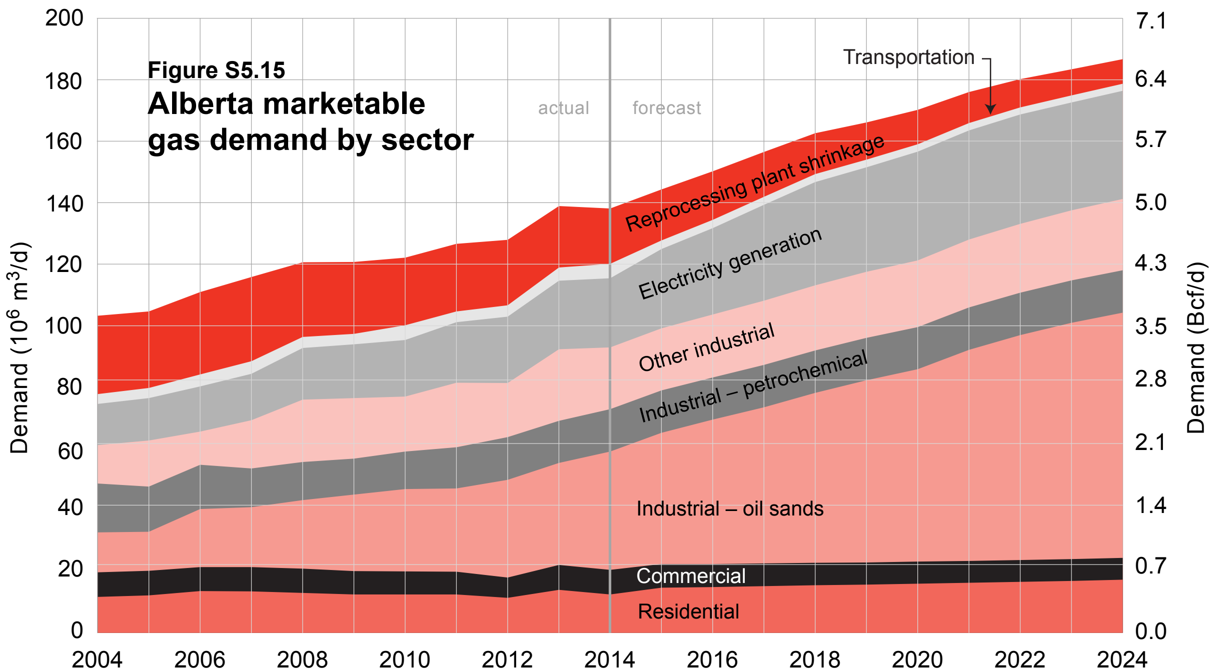


Figure S5.15
Alberta marketable gas demand by sector

Another significant increase in Alberta demand is due to projected development in the industrial sector. Gas demand for oil sands operations is forecast to increase from 38.5 10^6 m^3/d in 2014 to 79.8 10^6 m^3/d in 2024.[6] **Table S5.9** outlines the average purchased gas use rates for oil sands operations.

As noted earlier, oil sands upgrading operations produce process gas that is used on site. The in situ operations also produce solution gas from bitumen wells. **Figure S5.16** shows total gas use by the oil sands sector, including gas used for in situ recovery, mining and upgrading, and electricity cogeneration. The gas supply sources include purchased gas,[7] process gas from mining and upgrading operations, and produced gas from bitumen wells. Gas use by the oil sands sector was 88.5 10^6 m^3/d in 2014 and is expected to increase to 145.0 10^6 m^3/d by 2024.

Figure S5.17 shows total Alberta natural gas demand and production. Natural gas produced from bitumen wells or from bitumen upgrading is considered to be used on site and is not included as marketable production available to meet Alberta demand. Therefore, gas removals from the province represent natural gas production from conventional and CBM production (and do not include imports from British Columbia) minus Alberta demand.

In 2014, demand within Alberta was 138.0 10^6 m^3/d, which represented 48.0 per cent of the total Alberta natural gas production. The remainder was sent to other Canadian provinces and the United States. By the end of the forecast period, demand is projected to reach 186.6 10^6 m^3/d, or 74.6 per cent of total Alberta production. However, the forecast does not include any shale gas production that is expected to occur in Alberta. Additionally, natural gas supply from British Columbia that moves through Alberta to market is not included in this analysis. The B.C. supply is expected to increase over the forecast period and provide Alberta with an additional source of natural gas if needed.

[6] Gas demand resulting from oil sands electricity cogeneration is included with industrial oil sands demand.

[7] Gas that is purchased from outside the scheme to be used in the recovery of bitumen.

Table S5.9 Average use rates of purchased gas for oil sands operations, 2014

	Excluding purchased gas for cogeneration		Including purchased gas for cogeneration	
Extraction method	**(m³/m³)[a]**	**(mcf/bbl)[b]**	**(m³/m³)**	**(mcf/bbl)**
In situ				
SAGD[c]	148	0.8	202	1.134
CSS[d]	165	0.9	213	1.20
Mining with upgrading	82	0.5	123	0.69

[a] Expressed as cubic metres of natural gas per cubic metre of upgraded or nonupgraded bitumen production. Rates are an average of typical schemes with sustained production.

[b] Million cubic feet per barrel.

[c] Steam-assisted gravity drainage.

[d] Cyclic steam stimulation.

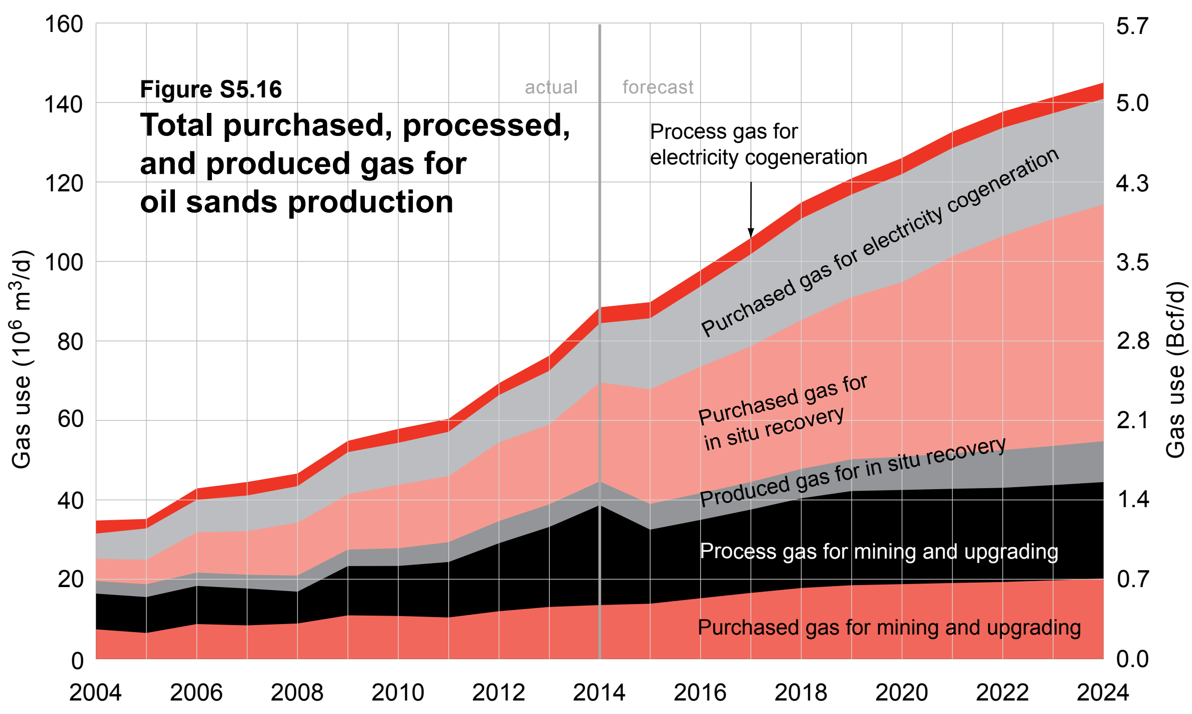


Figure S5.16
Total purchased, processed, and produced gas for oil sands production

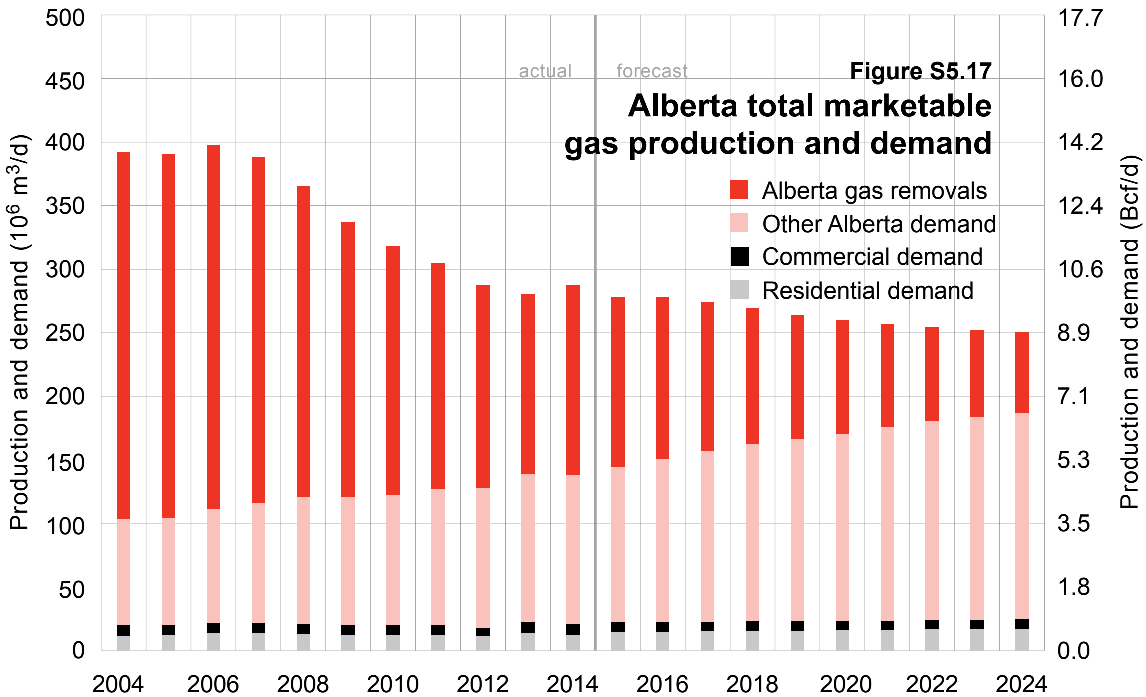


Figure S5.17
Alberta total marketable gas production and demand
actual
forecast
Alberta gas removals
Other Alberta demand
Commercial demand
Residential demand
Production and demand (10^6 m^3/d)
Production and demand (Bcf/d)
500
450
400
350
300
250
200
150
100
50
0
17.7
16.0
14.2
12.4
10.6
8.9
7.1
5.3
3.5
1.8
0.0
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024

HIGHLIGHTS

Pentanes plus production in Alberta surpassed heavy oil production for the first time in 2014.

The Vantage pipeline was commissioned in June 2014 and delivers ethane from North Dakota to Alberta.

The western leg of the Cochin pipeline was reversed to supply condensate from the United States to Alberta.

6 NATURAL GAS LIQUIDS

Produced natural gas is primarily methane, but it also contains heavier hydrocarbons consisting of ethane (C_2), propane (C_3), butanes (C_4), and pentanes and heavier hydrocarbons (typically referred to as pentanes plus or C_5+), all of which are referred to as natural gas liquids (NGLs). Natural gas also contains water and contaminants such as carbon dioxide (CO_2) and hydrogen sulphide (H_2S). In Alberta, the production of all ethane, pentanes plus, and most propane and butanes are from the raw natural gas stream. Most of the NGL supply is recovered from the processing of natural gas at gas plants, although some pentanes plus is recovered as condensate at the field level and sold as product. Other sources of NGLs are crude oil refineries, where small volumes of propane and butanes are recovered, and from gases produced as by-products of bitumen upgrading, called off-gas. Off-gas is a mixture of hydrogen and light gases, including ethane, propane, and butanes. Most of the off-gas produced from oil sands upgraders is currently being used as fuel for oil sands operations. Coalbed methane (CBM) is generally dry gas, so it is not expected to contribute to future NGL reserves. Shale gas appears to have a wide range of liquids content, from lean to liquids-rich. Consequently, depending on development trends, shale gas may contribute significantly to the province's NGL reserves in the future.[1]

The AER estimates remaining reserves of NGLs based on volumes expected to be recovered from remaining raw natural gas using existing technology and projected market conditions, which are described in **Section 6.2.1**. Initial reserves for NGLs are not calculated since historically only a fraction of the liquid volume that could have been extracted was recovered, and much was flared for lack of market demand. The AER's projections for the overall recovery of each NGL component are explained in **Section 5.1.3.5**. As shown graphically in **Figure R5.8**, the estimate of the reserves of liquid ethane is based on the assumption that 65 per cent of the total raw ethane gas reserves will be extracted from the natural gas stream, while 85 per cent of propane, 90 per cent of butane, and 100 per cent of pentanes plus are assumed extracted from the gas stream. Although it is reasonable to expect that some heavier liquids will drop out in the reservoir as pressure declines with depletion and will not be recovered, the AER's calculations assume that the

[1] A trend may be developing in Alberta with respect to the content of in-place and extractable volumes of NGLs in unconventional tight gas and shale gas reservoirs. Conventional reservoirs generally hold a relatively well understood range of NGL content from lean to wet. Some tight gas and shale gas reservoirs may produce unusually high levels of NGLs, making them "liquids rich." The AER is following this development and may review its NGL reserve calculation process as appropriate.

composition of raw produced gas remains unchanged over the life of a pool because it is difficult to predict, and the volume is not expected to be significant. NGLs expected to be removed from natural gas are referred to as extractable reserves, and those not expected to be recovered are included as part of the province's natural gas reserves, as discussed in **Section 5.1**.

6.1 Reserves of Natural Gas Liquids

6.1.1 Provincial Summary

Estimates of the remaining established reserves of extractable NGLs in 2014 are summarized in **Table R6.1** and **Table R6.2**. Remaining established reserves of extractable NGLs compared with 2014 production are shown in **Figure R6.1**.

Total remaining reserves of extractable NGLs have decreased by 3.2 per cent compared with 2013 due to the decrease in natural gas reserves. Fields that have contributed significantly to this decrease are Caroline, Pembina, Pine Creek, Sundance, and Westerose South. These fields and others containing large NGL volumes are listed in **Appendix B**, **Table B.6** and **Table B.7**.

6.1.2 Ethane

As of December 31, 2014, the AER estimates remaining established reserves of extractable ethane to be 106.5 million (10^6) cubic metres (m^3) in liquefied form. Of that, 42.4 10^6 m^3 is expected to be recovered from field plants and 64.0 10^6 m^3 from straddle plants that deliver gas outside the province, as shown in **Table R6.2.**

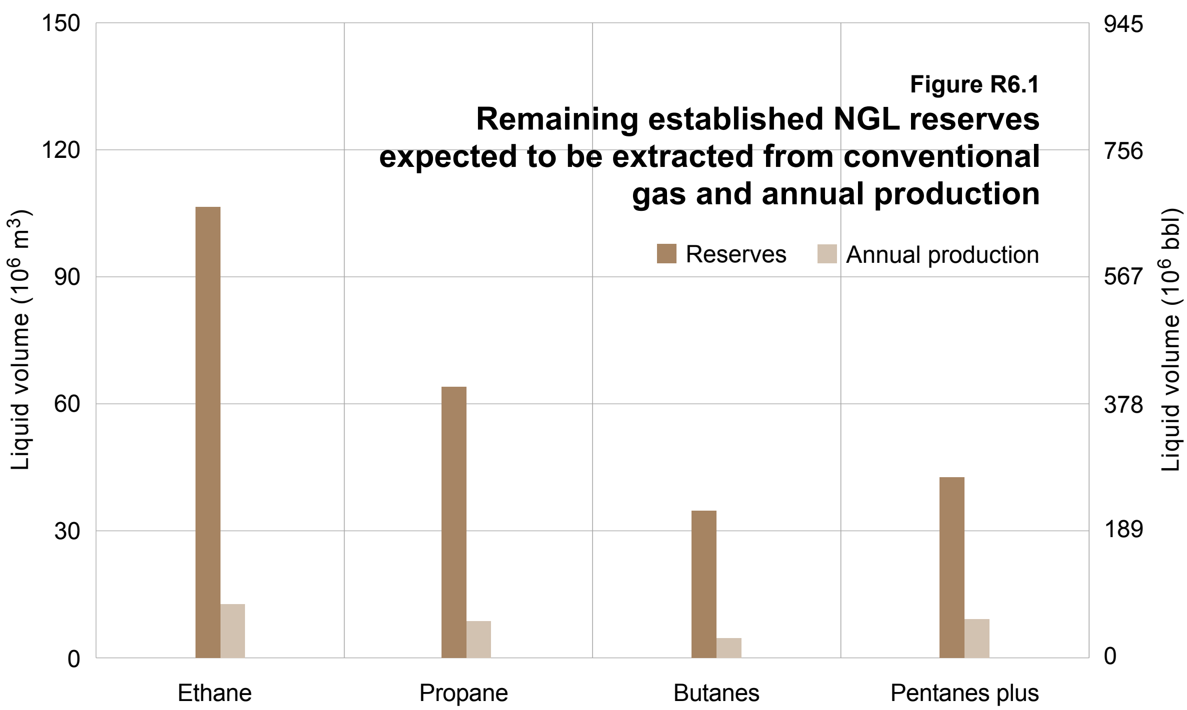


Figure R6.1
Remaining established NGL reserves expected to be extracted from conventional gas and annual production

Table R6.1 Established reserves and production change highlights of extractable NGLs (10^6 m^3 liquid)[a]

	2014	2013	Change
Cumulative net production			
Ethane	343.8	331.1	+12.7
Propane	320.6	311.9	+8.7
Butanes	182.1	177.4	+4.7
Pentanes plus	383.3	374.2	+9.1
Total	**1 229.8**	**1 194.6**	**+35.2**
Remaining established reserves (expected to be extracted)			
Ethane	106.5	110.5	−4.0
Propane	64.0	65.5	−1.5
Butanes	34.7	35.4	−0.6
Pentanes plus	42.7	44.9	−2.2
Total	**247.9**	**256.3**	**−8.3**
	(1 565 10^6 bbl)[b]	**(1 617 10^6 bbl)[b]**	
Annual production	**35.2**	**33.8**	**+1.4**

[a] 10^6 m^3 = million cubic metres.

[b] bbl = barrels.

Table R6.2 Reserves of NGLs as of December 31, 2014 (10^6 m^3 liquid)

	Ethane	Propane	Butanes	Pentanes plus	Total
Total NGLs in remaining raw gas	162.5	75.3	38.6	42.7	319.1
Liquids expected to remain in dry marketable gas	56.0	11.3	3.9	0.0	71.2
Remaining established reserves recoverable from					
Field plants	42.4	37.7	23.2	38.4	141.7
Straddle plants	64.0	26.4	11.6	4.3	106.3
Total	**106.5**	**64.0**	**34.7**	**42.7**	**247.9**

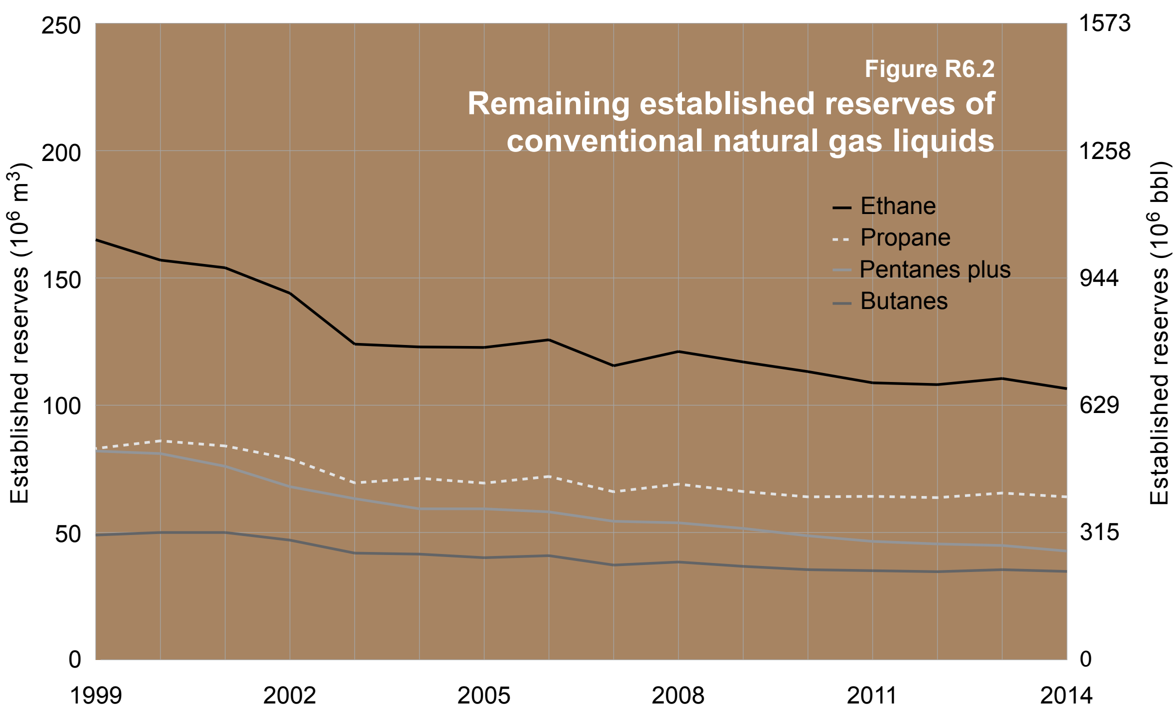
Thirty-five per cent of the total raw ethane, or 56.0 10^6 m^3 (liquid), is estimated to remain in the marketable gas stream and could potentially be recovered. **Figure R6.2** shows the remaining established reserves of ethane declining rapidly from 1996 to 2003, then levelling off as more ethane is extracted from raw gas. In 2014, 12.7 10^6 m^3 of specification ethane was extracted, compared with 13.1 10^6 m^3 in 2013.

For individual gas pools, the ethane content of gas in Alberta varies considerably, falling within the range of 0.25 to 20 per cent. As shown in **Appendix B**, **Table B.6**, the volume-weighted average ethane content of all remaining raw gas is 5.2 per cent. Also listed in this table are ethane volumes recoverable from fields containing the largest ethane reserves. Of these fields, the ten largest—in alphabetical order, Ansell, Elmworth, Kakwa, Kaybob South, Pembina, Sundance, Rainbow, Wapiti, Wild River, and Willesden Green—account for 34 per cent of the total ethane reserves but only 21 per cent of remaining established marketable gas reserves.

6.1.3 Other Natural Gas Liquids

As of December 31, 2014, the AER estimates remaining extractable reserves of propane, butanes, and pentanes plus to be 64.0 10^6 m^3, 34.7 10^6 m^3, and 42.7 10^6 m^3, respectively. This change is due to the decrease in natural gas reserves. The breakdown in the liquids reserves at year-end 2014 is shown in **Table R6.2**.

Table B.7 in **Appendix B** lists propane, butanes, and pentanes plus reserves in fields containing the largest remaining liquids reserves. The ten largest of these fields—in alphabetical order, Ansell, Brazeau River, Elmworth, Kakwa, Kaybob South, Pembina, Rainbow, Wapiti, Wild River, and Willesden Green—account for about 32 per cent of the total propane, butanes, and pentanes plus liquid reserves. The volumes recoverable at straddle plants are not included in the field totals but are shown separately at the end of the table.



6.1.4 Ultimate Potential

The remaining ultimate potential of liquid ethane is determined based on projected market demand and the volumes that could be recovered as liquid from the remaining ultimate potential of natural gas using existing cryogenic technology. The percentage of ethane volumes that have been extracted have been generally increasing over time. The AER estimates that 70 per cent of the remaining ultimate potential of ethane gas will be extracted. Based on a remaining ethane gas ultimate potential of 99 billion (10^9) m^3, the AER estimates the remaining ultimate potential of liquid ethane to be 248 10^6 m^3. The other 30 per cent, or 30 10^9 m^3, of ethane gas is expected to be sold for its heating value as marketable natural gas.

For liquid propane, butanes, and pentanes plus combined, the remaining ultimate potential is 299 10^6 m^3. This assumes that the remaining ultimate potential as a percentage of the initial ultimate potential is similar to that of conventional marketable gas—about 26 per cent.

Additionally, 9301 10^6 m^3 of unconventional, in-place NGLs in six key shale formations in Alberta have been identified by the shale- and siltstone-hosted hydrocarbon resources study discussed in **Section 2.2.2**. This very large resource represents a huge potential for future development, but the technical, economic, environmental, and social constraints on recoverability were not included in the study.

As discussed in **Section 2.3.3**, a joint government report was released in 2013 on the ultimate potential of one of the major shale- and siltstone-hosting hydrocarbon units in Alberta, the Montney Formation. The report estimated that from the 4863 10^6 m^3 of expected in-place NGLs, some 298 10^6 m^3 might ultimately be recovered. If similar results were to be estimated in the other formations, the increase to the ultimate potential of NGLs in Alberta could be substantial.

6.2 Supply of and Demand for Natural Gas Liquids

Ethane and other NGLs are recovered mainly from the processing of natural gas. Field gas processing facilities ensure that natural gas meets the quality specifications of natural gas pipeline systems, which may require removing NGLs to meet pipeline hydrocarbon dew point specifications.[2] Removal of other gas contaminants, such as hydrogen sulphide (H_2S) and carbon dioxide (CO_2), is also required. Field plants generally recover additional volumes of NGLs—more than what is required to meet pipeline specifications, depending on the plant's extraction capability—and sold separately to obtain full value for the NGL components. Generally, the heavier NGLs (butanes and pentanes plus) are removed at field plants. Field plants send recovered NGL mix to centralized, large-scale fractionation plants where the mix is fractionated into specification products.

Liquids that are heavy enough to be naturally collected at the field level due to the drop in pressure and temperature are called condensate. The properties of condensate and pentanes plus are similar, and the terminology is often used interchangeably as both are marketed in the same way in western Canada. The term pentanes plus is used in this report.

[2] The dew point is the temperature at which hydrocarbon molecules condense out of the gaseous phase.

Gas reprocessing plants, often referred to as straddle plants, recover NGL components or NGL mix from marketable gas. They are usually located on main gas transmission pipelines at border delivery points. Straddle plants remove much of the propane plus (C_3+) and ethane volumes, with the degree of recovery being determined by the plant's extraction capability, contractual arrangements, and product demand. **Figure S6.1** illustrates the stages involved in processing raw gas and crude oil for the recovery of ethane, propane, butanes, and pentanes plus.

Figure S6.2 shows the pipeline systems that move ethane and ethane plus (C_2+) mix from the processing plants to market. Gas processing plants capable of extracting C_2+ mix NGLs are typically tied to C_2+ mix NGL gathering systems that move liquids to NGL fractionators in the Fort Saskatchewan area. Ethane recovered at field processing plants, NGL fractionators, and the straddle plants is shipped on the Alberta ethane gathering system to the Alberta ethane market where it is then used as petrochemical feedstock for the petrochemical industry to produce ethylene and other products. Ethylene is an important building block for the manufacture of plastics.

6.2.1 Ethane and Other Natural Gas Liquid Production – 2014

In Alberta, there are nearly 500 active gas processing plants that recover NGL mix or specification products, 10 fractionation plants that fractionate NGL mix streams into specification products, and 9 straddle plants.

Recovery efficiencies of NGL specification products at field plants depend on plant design and economics and generally range from 75 to 98 per cent for propane, 90 to 100 per cent for butanes, and 98 to 100 per cent for pentanes plus. A few field plants are also capable of extracting ethane as a specification product or as a C_2+ mix and are referred to as deep-cut facilities. Details of NGL production highlights are shown in **Table S6.1**.

6.2.1.1 Ethane

Ethane recovery at straddle plants varies from 40 to 90 per cent, averaging 65 per cent. The average percentages of propane, butanes, and pentanes plus recovered at Alberta straddle plants are 98.5, 99.5, and 99.8, respectively. **Table S6.2** outlines information for 2014 about the straddle plants operating in Alberta, including the plant location, operator name, approved natural gas throughput volumes, natural gas receipts (actual throughput volumes), and the volume of specification ethane recovered (unless otherwise noted).

Conventional natural gas production in Alberta has been generally declining since reaching a peak in 2001 and has affected the amount of NGLs recovered at extraction facilities. In 2014, ethane volumes extracted at Alberta processing facilities decreased 2.8 per cent to 34.9 thousand (10^3) m^3/d from 35.9 10^3 m^3/d in 2013, presumed to be a result of market displacement due to lower priced imports.

About 71 per cent of total ethane in the gas stream was extracted in 2014, down from about 75 per cent extracted in 2013. The remainder was left in the gas stream and sold for its heating value. **Table S6.3** shows the volumes of specification ethane extracted at the three types of processing facilities during 2014. This table excludes the 1.2 10^3 m^3/d of ethane produced from off-gas in 2014.

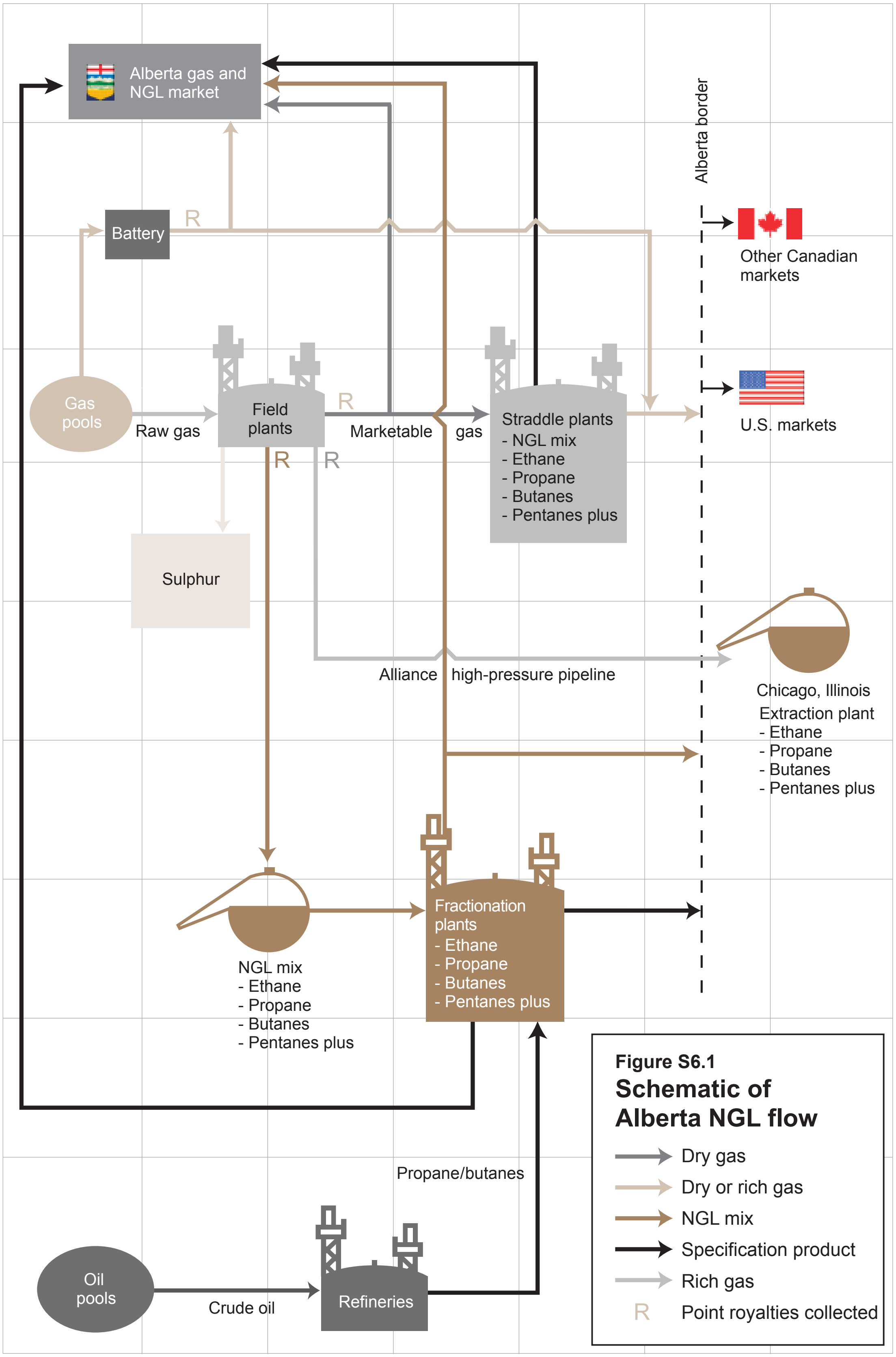


Figure S6.1
Schematic of Alberta NGL flow

Figure S6.2
Ethane gathering and delivery systems

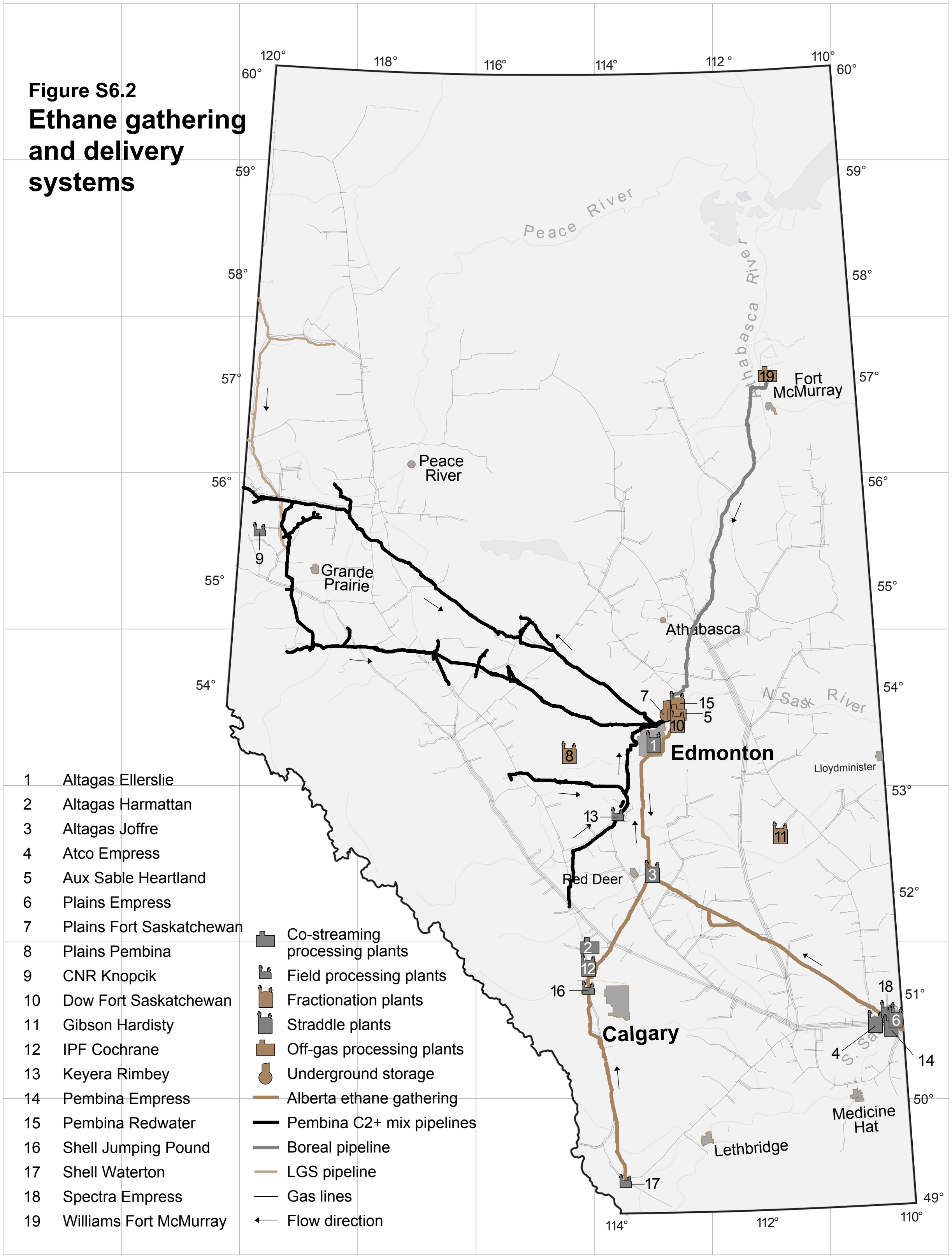


Table S6.1 NGL production and change highlights (10^3 m³/d liquid)

	2014	2013	Change	Change (%)[b]
Production				
Ethane[a]	36.1	36.7	−0.6	−1.6
Propane	23.7	23.4	+0.3	+1.3
Butane	12.9	12.6	+0.3	+2.2
Pentanes plus	25.0	20.8	+4.2	+19.9
Total	**97.7**	**93.5**	**+4.2**	**+4.5**

[a] Include volumes produced from off-gas.

[b] Per cent changes are based on annual production volumes.

Table S6.2 Straddle plants in Alberta, 2014

Area	Operator	Approved gas volumes (10^3 m³/d)	Gas receipts (10^3 m³/d)	Ethane production (m³/d)
Empress	Spectra Energy Empress Management	67 960	35 545	3 349
Empress	Plains Midstream Canada ULC	176 750	47 123	6 095
Cochrane	Inter Pipeline Extraction Ltd.	70 450	43 134	6 373
Ellerslie (Edmonton)	AltaGas Ltd.	11 000	8 304	1 295
Empress	ATCO Energy Solutions Ltd.	31 000	8 117	497
Fort Saskatchewan[a]	ATCO Energy Solutions Ltd.	1 051	361	0
Empress	1195714 Alberta Ltd.	33 809	33 098	4 385
Joffre (JEEP)	AltaGas Ltd.	7 066	884	702
Atim[a] (Villeneuve)	ATCO Energy Solutions Ltd.	1 133	268	0
Total		**400 219**	**176 834**	**22 696**

[a] These plants are approved to recover a C_2+ mix and not specification ethane.

Table S6.3 Ethane extraction volumes at gas plants in Alberta, 2014

Gas plants	Volume (10^3 m³/d)	Percentage of total
Field plants	2.2	6.3
Fractionation plants	8.9	25.5
Straddle plants	23.8	68.2
Total	**34.9**	**100.0**

Ethane extracted at field plants in 2014 decreased by 15.4 per cent compared to 2013. Ethane recovered at straddle plants in 2014 decreased by 6.3 per cent over 2013. Ethane recovered at fractionation plants in 2014 was up 12.7 per cent because of operators targeting wet gas areas in Alberta.

The C_2+ mix NGLs shipped from British Columbia to Alberta fractionation plants for fractionation into specification products was about 2.6 10^3 m^3/d in 2014 and is included in Alberta production volumes.
As conventional gas production declines, less ethane will be available for use by the petrochemical sector. To address the tight supply of ethane in Alberta, the provincial government implemented its Incremental Ethane Extraction Program (IEEP) in 2006 and amended and extended it in 2011. The program has been revised to also encourage ethane extraction from off-gases that result from bitumen upgrading or refining. Alberta's petrochemical industry is the largest in Canada and depends on the availability of competitively priced ethane to remain viable.

The province's IEEP is in effect until December 31, 2016. In Alberta, fractionation credits are given to petrochemical companies that consume incremental ethane for value-added upgrading to ethylene and derivatives. Credits are owned by the company that consumes the ethane or ethylene and can be sold to either a natural gas or bitumen royalty payer to be applied against its royalty obligation.

Sixteen IEEP projects have been approved to date. The 2014 IEEP projects are listed in **Table S6.4**. The $350 million program is fully allocated and will facilitate production of 14.5 10^3 m^3/d of ethane.

Table S6.4 Approved IEEP projects as of December 31, 2014

Feedstock type	Project name	Applicant	Submission year
Conventional	Empress V Deep Cut	Dow	2008
Conventional	Rimbey Ethane Extraction	Dow	2008
Conventional	Hidden Lake Streaming	Nova	2010
Off-gas	Williams Off-Gas Ethane Extraction (Phase 1)	Nova	2010
Conventional	Musreau Deep Cut	Dow	2011
Conventional	Shell Waterton Incremental NGL Recovery	Shell	2011
Off-gas	Scotford Fuel Gas Recovery (Refinery)	Shell	2011
Conventional	Harmattan Plant Co-stream	Nova	2011
Conventional	Shell Jumping Pound	Shell	2012
Off-gas	Shell Scotford Upgrader Off-Gas	Shell	2012
Off-gas	Williams Off-Gas Ethane Extraction (Phase 2)	Nova	2012
Conventional	AltaGas-Gordondale Deep Cut	Nova	2012
Conventional	Judy Creek Ethane Extraction	Nova	2012
Conventional	Resthaven Facility Phase 1	Dow	2012
Conventional	Rimbey Turbo Expander	Dow	2012
Conventional	Project Turbo (Saturn Plant)	Dow	2012

Source: Alberta Department of Energy.

6.2.1.2 Propane, Butanes, and Pentanes Plus

Propane and butanes production in 2014 continued to grow, which it has been doing since 2011. In 2014, propane production increased by 1.3 per cent to 23.7 10^3 m^3/d, compared to 23.4 10^3 m^3/d in 2013. Butanes production rose by 2.2 per cent in 2014 to 12.9 10^3 m^3/d, relative to 12.6 10^3 m^3/d in 2013. Since 2012, the overall increase in the production of these NGLs has come as a result of infrastructure developments and producers targeting wet gas areas in the Petroleum Services Association of Canada (PSAC) Areas 2, 5, and 7.

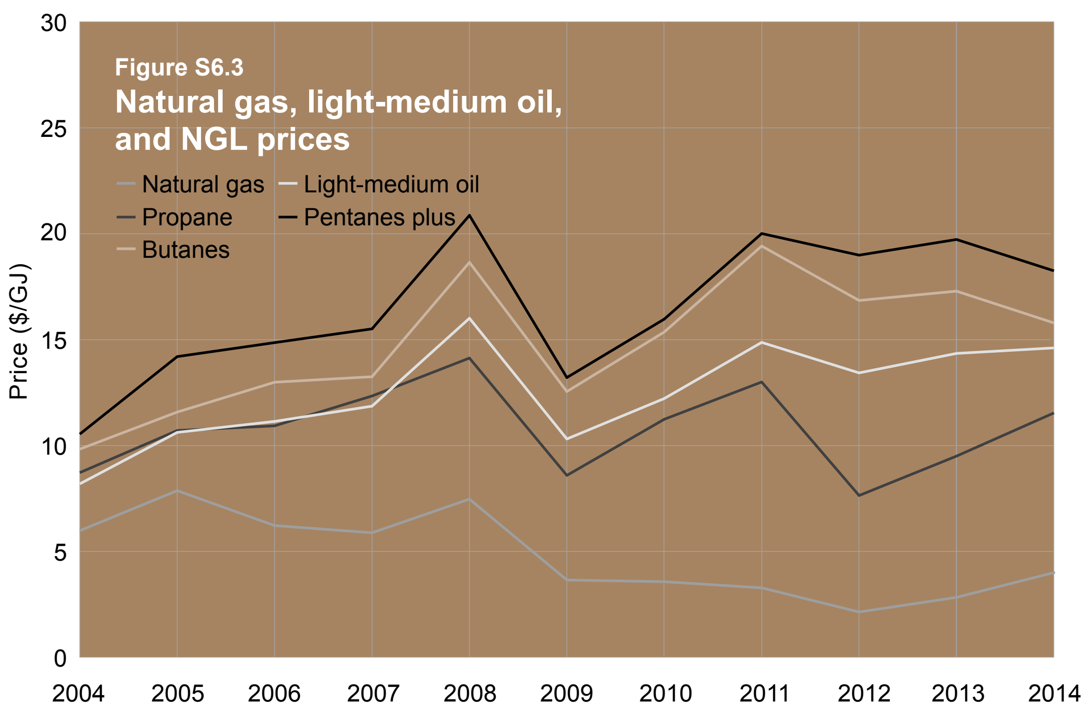
Pentanes plus production rose by 19.9 per cent in 2014 over 2013. In 2014, 25.0 10^3 m^3/d of pentanes plus were produced compared with 20.8 10^3 m^3/d in 2013. For the first time since 2007, pentanes plus production has increased and has surpassed heavy oil production in Alberta. This is driven by demand for pentanes plus, which is used to dilute crude bitumen for pipelining.

Production of conventional natural gas from PSAC Area 2 was up 8.9 per cent over 2013. This area has the largest remaining extractable liquids reserves in the province. It declined in all other PSAC areas.

Figure S6.3 shows the historical natural gas and liquids prices in Canadian dollars per gigajoule (Cdn$/GJ). The figure shows that propane, butanes, and pentanes plus prices follow the light-medium crude oil price.

6.2.2 Ethane and Other Natural Gas Liquids Production – Forecast

In forecasting ethane and other NGLs, the AER recognizes that NGL content, gas plant recovery efficiencies, NGL prices, and gas production volumes from remaining established reserves and future gas reserves additions affect future production.



Ethane, propane, and butanes production are projected to increase from 2015 through 2017 based on the assumption that operators will continue to focus on wet-gas plays. The AECO-C[3] natural gas price in Alberta remain weak, and the economics of producing natural gas are improved when the natural gas contains NGLs.

Announced processing facility projects, discussed in **Section 9.2.2**, are expected to increase liquids recovery to an estimated total of 36.4 10^3 m^3/d by 2017. This anticipated change is due to the addition of a de-ethanizer, C2+ and C3+ expansions, the debottlenecking of current capacities, and pipeline connections.

6.2.2.1 Ethane

Figure S6.4 shows the AER's ethane supply and demand forecast. The ethane production forecast from natural gas is based on the natural gas forecast and the assumption of the NGL content in the natural gas stream. Ethane production from conventional natural gas is expected to increase to 35.1 10^3 m^3/d in 2015 and continue to increase until 2017 before it declines slightly in 2018 and levels off in 2024. Small volumes of ethane produced from oil sands off-gas are expected to increase to 2.7 10^3 m^3/d by 2024. The AER expects the ethane from off-gas to continue to grow gradually over the forecast period based on the forecast for processed gas from upgraded production shown in **Figure S5.16**, as discussed in **Section 5.2.6.4**. The ethane demand forecast is discussed in **Section 6.2.3.1**.

6.2.2.2 Propane, Butanes, and Pentanes Plus

Figure S6.5, **Figure S6.6**, and **Figure S6.7** show the forecast for average daily production volumes and demand to 2024 for propane, butanes, and pentanes plus. The production forecast for propane, butanes, and pentanes plus is higher this year as a result of a higher natural gas production forecast. The propane, butanes, and pentanes plus demand forecasts are discussed in **Section 6.2.3.2**.

The AER expects propane production to increase from 23.7 10^3 m^3/d in 2014 to 23.9 10^3 m^3/d in 2015. Propane production is expected to slightly increase in 2016 and continue to increase through to 2017, after which it will begin to decline in 2018 before leveling off in 2024.

Butanes production is predicted to remain steady at 12.9 10^3 m^3/d in 2015, relatively unchanged from 2014. Production will increase until 2017 and will soften and stay relatively flat until the end of the forecast period. The butanes production forecast will reach 13.0 10^3 m^3/d in 2024.

Pentanes plus production in Alberta is expected to decline slightly, from 25.0 10^3 m^3/d in 2014 to 24.4 10^3 m^3/d in 2015. It will continue this slight decline until 2017 as liquid prices for pentanes plus slowly recover. Production will be relatively flat for the remainder of the forecast, reaching 23.5 10^3 m^3/d in 2024. This is slightly higher than last year's forecast of 21.0 10^3 m^3/d in 2023. The AER's pentanes plus production forecast is higher than what was forecasted last year due to an increased natural gas production forecast as operators are targeting liquids-rich areas.

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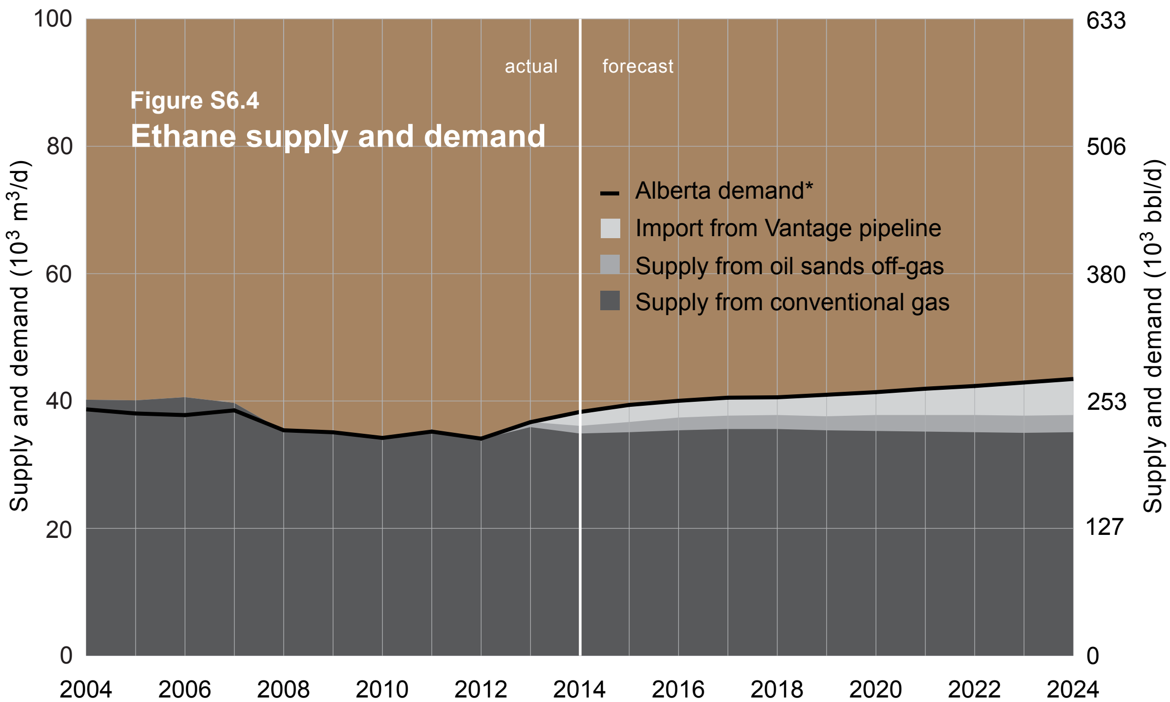
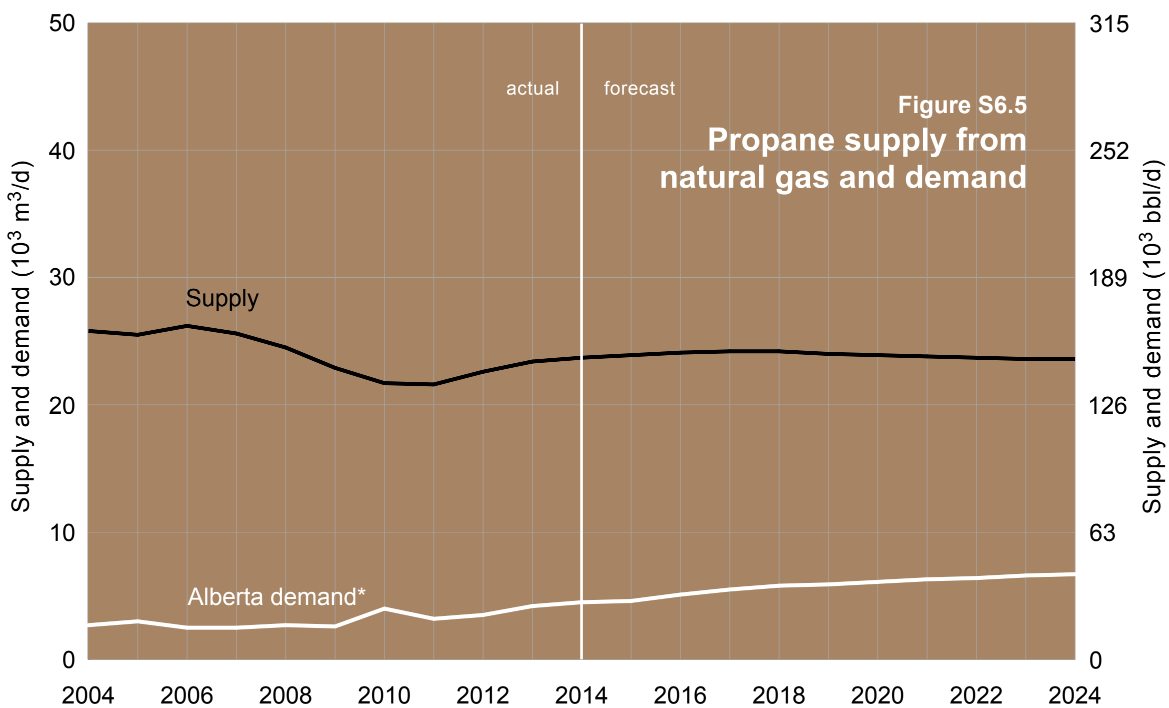
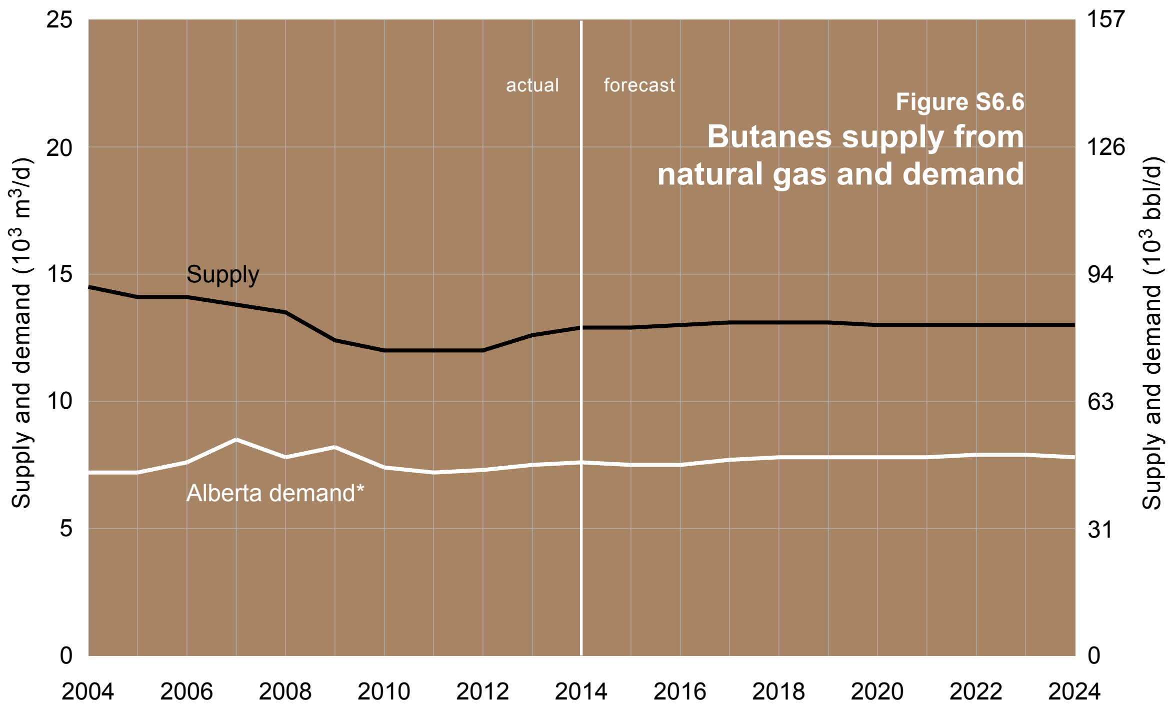
[3] The AECO-C hub is a trading point that represents the main pricing index for Albertan and Canadian natural gas.



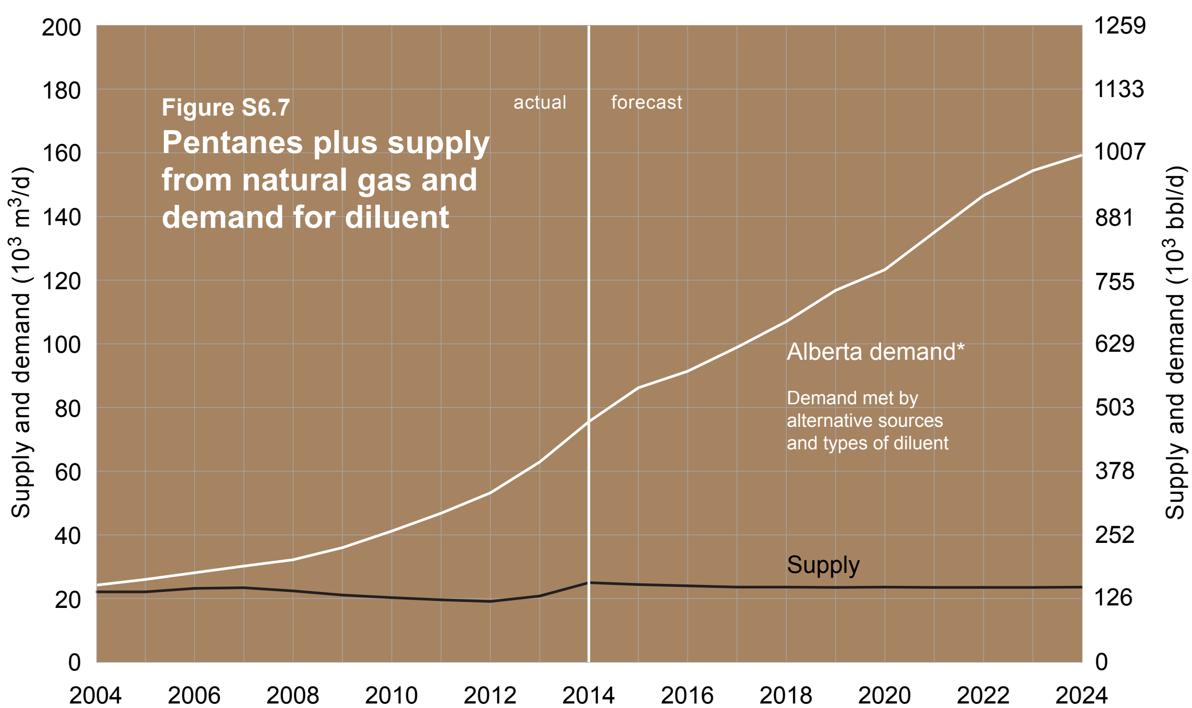
* Excludes solvent flood volumes.



* Excludes solvent flood volumes.



* Excludes solvent flood volumes.



* Excludes solvent flood volumes.

6.2.3 Demand for Ethane and Other Natural Gas Liquids

NGL use reaches nearly all sectors of the economy, being used in space heating and cooking, as feedstock for petrochemical facilities, in vehicle fuel, as a solvent for enhanced oil recovery (EOR), and as a diluent when blended into heavy oil or bitumen for pipeline transportation.

6.2.3.1 Ethane

The petrochemical industry in Alberta is the major consumer of ethane recovered from natural gas, with four ethylene plants using ethane as feedstock for the production of ethylene. Currently, small volumes of propane supplement the ethane supplies used at the petrochemical plants at Joffre, where three of the four plants are located. The fourth is in Fort Saskatchewan. The plants in the province that use ethane as a feedstock operated collectively at 73 per cent of their capacity in 2014. To meet the demand for ethane from the petrochemical industry, Alberta imports ethane produced in North Dakota via the Vantage pipeline. Ethane imports from North Dakota began deliveries in June 2014 and reported up to 2.2 10^3 m^3/d of ethane at the end of 2014.

The AER expects that ethane demand by the ethylene producers in the province will continue to increase over the forecast period based on the continued investment in Alberta infrastructure, such as pipelines and extraction facilities discussed in **Section 9.1.1.2** and **Section 9.2.2**. The petrochemical industry, which uses ethane as a feedstock, benefits from the lower ethane price environment. NOVA Chemicals is continuing construction on the expansion of their polyethylene facilities at the Joffre site, which will produce between 0.43 million to 0.50 million tonnes of linear low-density polyethylene per year. The expansion is expected to start up in 2016. As shown in **Figure S6.4**, Alberta demand for ethane is projected to gradually increase from 39.4 10^3 m^3/d in 2015 to 43.5 10^3 m^3/d in 2024. Since 2008, there have been no ethane removals from the province; this is expected to remain the case over the forecast period.

Demand for NGL mix streams in the form of C_2+ mix and C_3+ mix to be used as a solvent for EOR schemes for conventional oil fields exists in Alberta. Most of the NGL mix solvent is extracted at deep-cut facilities located next to the injection facilities. In 2014, the ethane volumes in the solvent used for this purpose were equivalent to about 2 per cent of total ethane demand in Alberta. The AER expects that the demand for NGL mix volumes will remain unchanged over the forecast period.

6.2.3.2 Propane, Butanes, and Pentanes Plus

Figure S6.5 shows Alberta's demand for propane compared with the total available production of propane from gas processing and straddle plants. The difference between Alberta requirements and total supply represents volumes used by ex-Alberta markets. Propane is used primarily as a fuel in remote areas for space and water heating, as an alternative fuel in motor vehicles, for grain drying, and for barbecues. Alberta propane demand is expected to increase slightly from 4.5 10^3 m^3/d in 2014 to 4.6 10^3 m^3/d in 2015, and then grow to 6.7 10^3 m^3/d by 2024. Propane and butanes injected as a solvent were equivalent to 16.0 per cent and 4.6 per cent of the provincial total demand for the products, respectively. Small volumes of pentanes plus were also injected as solvent in 2014.

With the reversal and conversion of the Cochin pipeline from propane exports to condensate imports, and an increased focus on wet natural gas drilling, Alberta's supply of propane will exceed its demand. However, demand for propane from the petrochemical sector is expected to continue to grow moderately over the forecast period because propane is used as a feedstock for propylene and ethylene. Propane demand is also expected to increase because of the construction of a propane dehydrogenation (PHD) facility, which will produce polymer grade propylene, a petrochemical feedstock used in plastics manufacturing by using propane derived from converted oil sands off-gas. It is anticipated that this facility will become operational in 2016. There are also export opportunities for Alberta propane supplies. Recently, Keyera and Plains Midstream both announced plans to construct a rail terminal near Fort Saskatchewan, which will transport propane out of western Canada.

Figure S6.6 shows demand in Alberta for butanes compared with the total available supply from gas processing plants. As with propane, the difference between the requirements in Alberta for butanes and total supply is the volumes used by markets outside of Alberta. Butanes are used as refinery feedstock and in gasoline blends as an octane enhancer.

Alberta demand for butanes is to remain unchanged at 7.6 10^3 m^3/d in 2015 compared to 2014. Butanes demand is expected to grow to 7.8 10^3 m^3/d by 2024. Alberta demand for butanes over the forecast period is expected to increase with the predicted increases in nonupgraded bitumen. Another potential source for growth in demand for butanes is the increasing use in the solvent-aided process (SAP). SAP is a process whereby in situ bitumen producers inject butanes as a solvent to enhance, along with steam-assisted gravity drainage (SAGD), bitumen recovery. Butanes are also used as diluent and blended with heavy crude oil and bitumen to facilitate pipeline transportation by reducing its viscosity.

The largest use of Alberta pentanes plus is as a diluent in the blending of heavy crude oil and bitumen. **Figure S6.7** shows the AER estimate of Alberta demand for pentanes plus used for diluent compared with the total available supply, with assumptions incorporated for the different diluent requirements for rail and pipeline transportation. Pentanes plus is also used as feedstock for the refinery in Lloydminster; this small volume (0.9 10^3 m^3/d in 2014) is not included in the figure. Pentanes plus demand is estimated based on assumed blending factors and heavy oil and bitumen production.

Alberta demand for pentanes plus is expected to remain strong due to continued high diluent requirements based on the crude bitumen forecast, discussed in **Section 3.2.3**. As a result, demand for pentanes plus as a diluent is forecast to grow 14.0 per cent to 86.2 10^3 m^3/d in 2015, compared to 75.6 10^3 m^3/d in 2014, and increase up to 159.3 10^3 m^3/d by 2024.

As illustrated in **Figure S6.7**, demand for diluent exceeded Alberta supply around 2004. The demand estimated over the forecast period reflects the inadequate Alberta supply of pentanes plus since 2004, which has resulted in the assessment and use of alternative sources (imports) and other types of diluent. Currently, Alberta imports pentanes plus on trucks and rail cars and in pipelines. Alberta imports of pentanes plus is expected to increase over the next 10 years with growing oil sands demand.

The Cochin pipeline was reversed in March 2014 to import pentanes plus. The Cochin pipeline, with a capacity of 15.1 10^3 m^3/d, is now moving light condensate to Alberta to meet the growing demand from the oil sands industry.

Section 9.1.1.2 describes the main NGL pipeline systems in Alberta, including new pipeline project announcements, and the current and future sources of diluent that will be needed to facilitate transportation of nonupgraded bitumen to markets.

HIGHLIGHTS

Remaining established sulphur reserves decreased 3 per cent, mainly due to production.

Sulphur production from gas processing declined 12 per cent from 2013 to 2014, while sulphur production from crude bitumen declined by less than 1 per cent.

Total sulphur production decreased from 4.5 million tonnes in 2013 to 4.2 million tonnes in 2014.

7 SULPHUR

Sulphur is a chemical element found in conventional natural gas, crude bitumen, crude oil, and coal. It is extracted and sold primarily for making fertilizer. Currently, most produced sulphur is derived from the hydrogen sulphide (H_2S) contained in about 20 per cent of the remaining established reserves of conventional natural gas.

7.1 Reserves of Sulphur

7.1.1 Provincial Summary

The AER estimates the remaining established reserves of elemental sulphur in the province as of December 31, 2014, to be 114.2 million tonnes (10^6 t), down 3 per cent from 2013. This decrease is mainly due to production. **Table R7.1** shows the changes in sulphur reserves over the past year. The AER does not estimate sulphur reserves from sour crude oil since only a very small portion of Alberta's sour crude oil is refined in the province. Sulphur from thermal coal in Alberta is mostly removed in the form of sulphur dioxide (SO_2) to meet environmental emission standards and is disposed of without being recovered.

7.1.2 Sulphur from Natural Gas

The AER estimates that 18.3 10^6 t of remaining established sulphur from natural gas reserves were in sour gas pools at year-end 2014, a decrease of 5.7 per cent from 2013. Remaining established sulphur reserves have been calculated using a provincial recovery factor of 97 per cent, which takes into account plant efficiency, acid-gas flaring at plants, acid-gas injection, and solution-gas flaring.

The AER's sulphur reserve estimates from natural gas are shown in **Table R7.2**. Fields containing the largest recoverable sulphur reserves are listed individually. Fields with significant volumes of sulphur reserves in 2014 are Waterton, Crossfield East, and Okotoks. Combined, these reserves account for 4.2 10^6 t, or 23 per cent, of the remaining established reserves of sulphur from natural gas.

The AER estimates the ultimate potential for sulphur from natural gas to be 394.8 10^6 t, which includes 40 10^6 t from pools with ultrahigh concentrations of H_2S currently not on production. Based on initial established reserves of 274.8 10^6 t, this leaves 120.0 10^6 t of yet-to-be-established reserves from future discoveries of conventional gas.

Table R7.1 Reserve and production change highlights (10^6 t)

	2014	2013	Change[a]
Initial established reserves			
Natural gas	274.8	273.8	+1.0
Crude bitumen[b]	128.4	128.4	0
Total	**403.2**	**402.2**	**+1.0**
Cumulative production			
Natural gas	256.5	254.4	+2.1
Crude bitumen	32.5	30.4	+2.1
Total	**289.0**	**284.8**	**+4.2**
Remaining established reserves			
Natural gas	18.3	19.4	−1.1
Crude bitumen[b]	95.9	98.0	−2.1
Total	**114.2**	**117.4**	**−3.2**
Annual production	4.2	4.5	−0.3

[a] Any discrepancies are due to rounding.

[b] Reserves of elemental sulphur from bitumen mines under active development as of December 31, 2014. Reserves from the entire surface mineable area are larger.

7.1.3 Sulphur from Crude Bitumen

Crude bitumen in oil sands deposits contains significant amounts of sulphur. As a result of bitumen upgrading operations, an average of 90 per cent of the sulphur contained in the crude bitumen is either recovered in the form of elemental sulphur or remains in the by-products from upgrading bitumen, such as coke.

It is currently estimated that 209.0 10^6 t of sulphur could be recovered from the 5.16 billion cubic metres (10^9 m^3) of remaining established crude bitumen reserves in the entire surface mineable area. These sulphur reserves were estimated by using a factor of 40.5 t of sulphur per thousand cubic metres of crude bitumen. This ratio reflects both current operations and the expected use of high-conversion hydrogen-addition upgrading technology for the future development of surface-mineable crude bitumen reserves. Hydrogen-addition technology recovers more sulphur than alternative carbon-rejection technology.

If less of the mineable crude bitumen reserves are upgraded with the hydrogen-addition technology than is currently estimated or if less of the mineable reserves are upgraded in Alberta, the total sulphur reserves will be less.

In 2014, the Nexen Long Lake upgrader continued to upgrade in situ bitumen, resulting in the production of small quantities of sulphur, most of which was not marketed. The AER will include in situ upgrading projects in future reports if they come on stream.

Table R7.2 Remaining established reserves of sulphur from natural gas as of December 31, 2014[a]

Field	Remaining reserves of marketable gas (10^6 m^3)	H_2S content (%)[b]	Remaining established reserves of sulphur	
			Gas (10^6 m^3)	Solid (10^3 t)
Bighorn	2 117	6.8	175	237
Brazeau River	8 397	3.2	316	428
Burnt Timber	1 489	20.6	466	632
Caroline	5 046	7.6	476	646
Coleman	747	26.6	296	402
Crossfield	2 290	18.3	657	891
Crossfield East	1 771	28.1	861	1 168
Elmworth	21 620	1.2	286	388
Hanlan	5 856	8.9	689	935
Jumping Pound West	2 844	6.7	237	321
La Glace	2 045	6.3	150	203
Limestone	2 727	12.6	463	628
Lone Pine Creek	1 830	7.0	156	212
Marsh	993	14.9	196	266
Moose	2470	12.7	412	558
Okotoks	1 440	32.1	851	1 154
Panther River	2 230	5.7	159	215
Pembina	22 994	0.6	197	267
Pine Creek	5 769	4.8	327	444
Rainbow	8 679	2.0	239	324
Rainbow South	2 480	6.8	248	337
Ricinus	3 526	4.0	161	219
Ricinus West	967	32.3	538	729
Simonette	2 855	8.1	329	446
Waterton	3 761	22.7	1 394	1 890
Wildcat Hills	5 550	4.4	284	385
Wimborne	1 493	9.4	168	228
Windfall	1 523	13.8	303	410
Subtotal	**122 509**	**6.8**	**11 034**	**14 963**
All other fields	742 813	0.3	2 458	3 351
Total	**865 322**	**1.4**	**13 491**	**18 313**

[a] Any discrepancies are due to rounding.

[b] Volume-weighted average based on remaining raw producible gas.

7.1.4 Sulphur from Crude Bitumen Reserves under Active Development

Only some of the crude bitumen produced from mining will be processed by the existing Suncor, Syncrude, Shell Scotford, and CNRL Horizon upgraders. Consequently, the AER's estimate of the initial established sulphur reserves in 2014 from these active projects is 128.4 10^6 t, representing 61 per cent of the potentially recoverable sulphur from the remaining established crude bitumen reserves for the entire surface mineable area. A total of 32.5 10^6 t of sulphur has been produced from these projects, leaving 95.9 10^6 t of remaining established reserves. This is a decrease of 2 per cent from the remaining reserves in 2013. This decrease in remaining reserves is due to the production of 2.1 10^6 t of sulphur in 2014.

7.2 Supply of and Demand for Sulphur

7.2.1 Sulphur Production – 2014

There are three main sources of sulphur production in Alberta: sour natural gas processing, crude bitumen upgrading, and crude oil refining. As shown in **Table S7.1**, Alberta produced 4.17 10^6 t of sulphur in 2014, of which 2.10 10^6 t were derived from sour gas, 2.05 10^6 t from bitumen upgrading, and just 0.015 10^6 t from oil refining. The total sulphur production in 2014 continued the downward trend that has been observed since 2000 due to lower sour gas production. Most of Canada's sulphur is produced in Alberta.

Table S7.1 Sulphur production and change highlights (10^6 tonnes)

	2014	2013	Change	Change (%)[a]
Production from				
Natural gas	2.10	2.38	−0.28	−11.8
Refining and upgrading	2.07	2.08	−0.01	−0.5
Total	**4.17**	**4.46**	**−0.29**	**−6.5**

[a] Per cent changes are based on annual production volumes.

7.2.1.1 Sulphur Production from Natural Gas

Table S7.2 shows sulphur production from major gas processing plants over the past year. The Shell Burnt Timber plant permanently closed down in 2014 and has not reported any production since July 2014. In 2014, Sulvaris Inc. received approval to build a new facility in central Alberta, which will be jointly owned by Keyera Partnership and Sulvaris Inc.

Sulphur stockpiles stored as solid blocks at gas processing plants have been drawn down significantly in recent years because of an increase in global sulphur demand. **Figure 15** in the Overview section illustrates historical sulphur closing inventories at gas processing plants and oil sands operations, as well as sulphur prices. Inventory blocks of sulphur at gas processing plants in Alberta were 1.03 10^6 t at year-end 2014, down from 1.22 10^6 t at year-end 2013 and 1.46 10^6 t in 2012.

Table S7.2 Sulphur production from gas processing plants (10^3 tonnes)

Major plants	2014	2013	Change	Change (%)
Shell Caroline	478	596	−118	−20
Shell Waterton	375	437	−62	−14
Husky Strachan	220	196	−24	−12
Shell Jumping Pound	169	168	+1	+1
Semcams Kaybob South	114	126	−12	−10
Keyera Strachan	87	96	−9	−10
Petro-Canada Hanlan	91	107	−16	−15
Shell Burnt Timber	36	108	−72	−67
Total	**1 570**	**1 834**	−264	−14

7.2.1.2 Sulphur Production from Crude Bitumen Upgrading

Historical sulphur production from the five oil sands upgrader operations is shown in **Figure S7.1**. Total production in 2014 was 2.06 10^6 t, down 1.2 per cent from 2013 production of 2.08 10^6 t. With the exception of Syncrude, the largest sulphur producer, all of the crude bitumen upgraders experienced increases in sulphur production. Syncrude did not have production between mid-September and mid-November due to maintenance.

7.2.2 Sulphur Production – Forecast

Total Alberta sulphur production from sour gas and the combination of bitumen upgrading and crude oil refining is shown in **Figure S7.2**. Sulphur production volumes are a function of sour gas production, sulphur content, and gas plant recovery efficiencies. This declining trend from natural gas is evident in the decline in sulphur production from gas processing plants since 2000. The decline is because of the lower natural gas production and lower sulphur content in the gas stream. Sulphur production from sour gas is expected to increase slightly from 2.10 10^6 t in 2014 to 2.29 10^6 t in 2016 and then fall to 2.10 10^6 t by the end of the forecast period. Sulphur recovery from bitumen upgrading has been on the rise since 1998 due to the increase in upgraded bitumen production—an increase that is expected to continue over the forecast period, rising from 2.07 10^6 t in 2014 to 2.74 10^6 t by 2024.

Sulphur recovery from Alberta refineries increased to 0.015 10^6 t in 2014 from 0.012 10^6 t in 2013. With the anticipation that Alberta refineries' throughput will slightly increase over time, sulphur recovery is expected to reach 0.018 10^6 t by 2024.

7.2.3 Sulphur Demand

Disposition of sulphur in Alberta averaged 460 10^3 t per year between 2008 and 2010. More recent data on the disposition of sulphur in the province may include Alberta plant-to-plant transfers, which have likely caused the disposition volume to appear higher than actual. The AER considers the 2008–2010 average to be representative of 2011 to 2014 disposition and has also used that figure in its forecast.

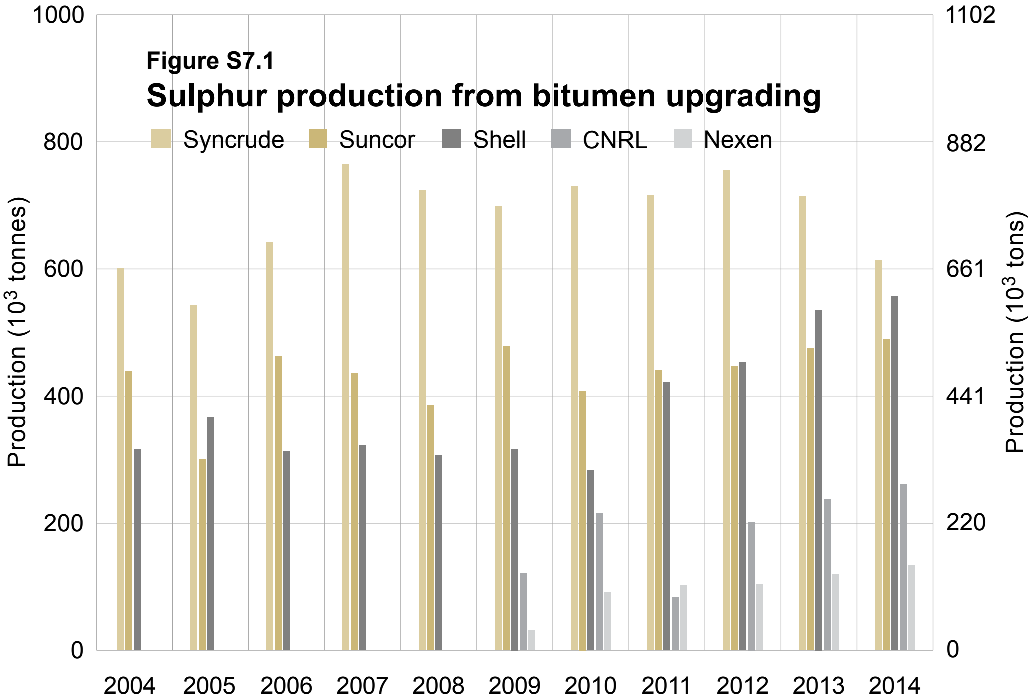


Figure S7.1
Sulphur production from bitumen upgrading
Syncrude
Suncor
Shell
CNRL
Nexen
Production (10³ tonnes)
Production (10³ tons)
1000
800
600
400
200
0
1102
882
661
441
220
0
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014

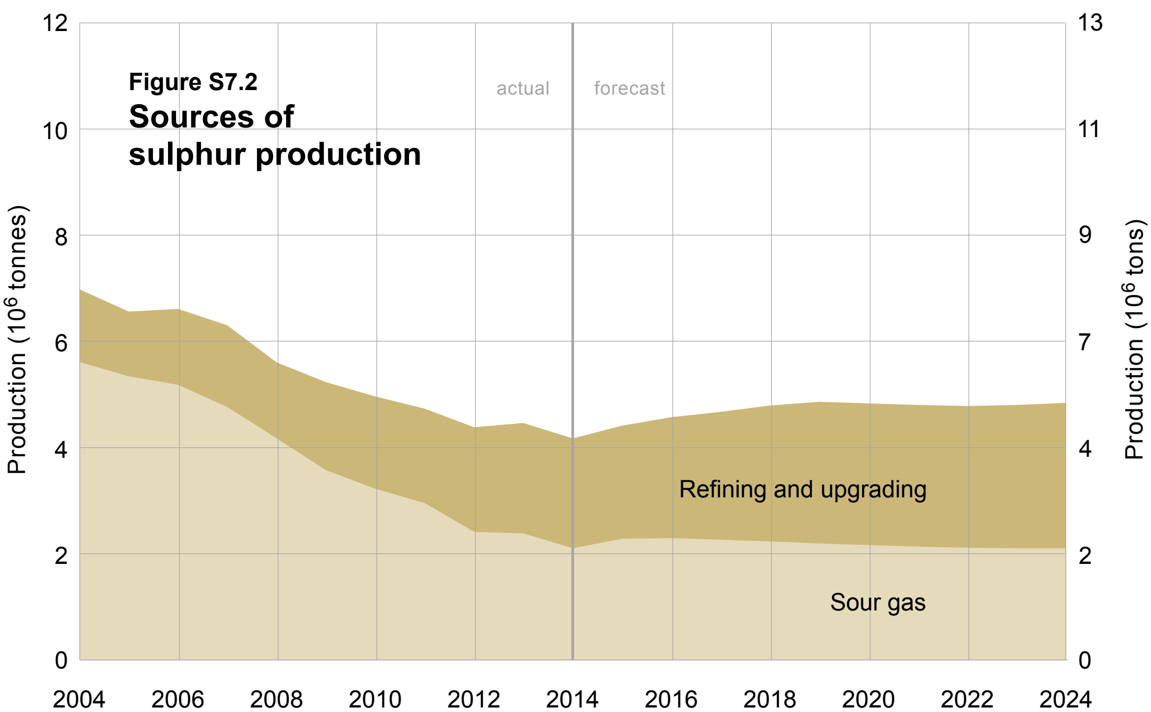


Figure S7.2
Sources of sulphur production
actual
forecast
Refining and upgrading
Sour gas
Production (10⁶ tonnes)
Production (10⁶ tons)
12
10
8
6
4
2
0
13
11
9
7
4
2
0
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024

Alberta produces more sulphur than any other province in Canada, and the majority of this Alberta production is shipped outside the province. Canadian exports in 2014 were 2.6 10^6 t, a 21.8 per cent decrease from 3.3 10^6 t in 2013. **Figure S7.3** shows the historical Canadian export volumes by market area.

Globally, about 10 per cent of sulphur is used as elemental sulphur; the remaining 90 per cent is consumed as sulphuric acid. Agriculture, specifically phosphate fertilizer, accounts for about 60 per cent of overall consumption. Sulphur use for metallurgical purposes is small at less than 10 per cent, but is expected to grow.

In 2014, Free On Board (FOB) Vancouver[1] sulphur prices averaged US$97 per tonne, decreasing 6.7 per cent from an average price of US$104 per tonne in 2013.

China is the world's largest importer of sulphur, using it primarily to make sulphuric acid to produce phosphate fertilizer. Exports to China have significantly decreased again from 265 thousand (10^3) t in 2013 to 68 10^3 t in 2014 because of increased availability from closer producing countries such as Saudi Arabia, Kazakhstan, Japan, South Korea, and Iran. Nearly half of Canadian exports are sent to the United States, which in 2014 was 1130 10^3 t—about 28.3 per cent lower than the 1578 10^3 t in 2013 because of falling sulphur demand in the United States.

Because sulphur is fairly easy to store, imbalances between production and disposition have traditionally been accommodated through net additions to or removals from sulphur stockpiles. If demand exceeds supply, sulphur is withdrawn from stockpiles; if supply exceeds demand, sulphur is added to stockpiles. **Figure S7.4** shows the historical and forecasted total sulphur supply and demand, including inventory additions and withdrawals.

Since 2004, supply and demand have generally been in balance, with small withdrawals from inventory stockpiles. The AER assumes that, on average, there will be a slight increase to stockpiles of sulphur. The forecast also assumes that Alberta demand will remain relatively constant at 0.46 10^6 t over the forecast period.

[1] FOB Vancouver represents an international pricing point where, after a commodity is loaded on a ship, the liability for and the cost of shipping the commodity transfers from a seller to a buyer.

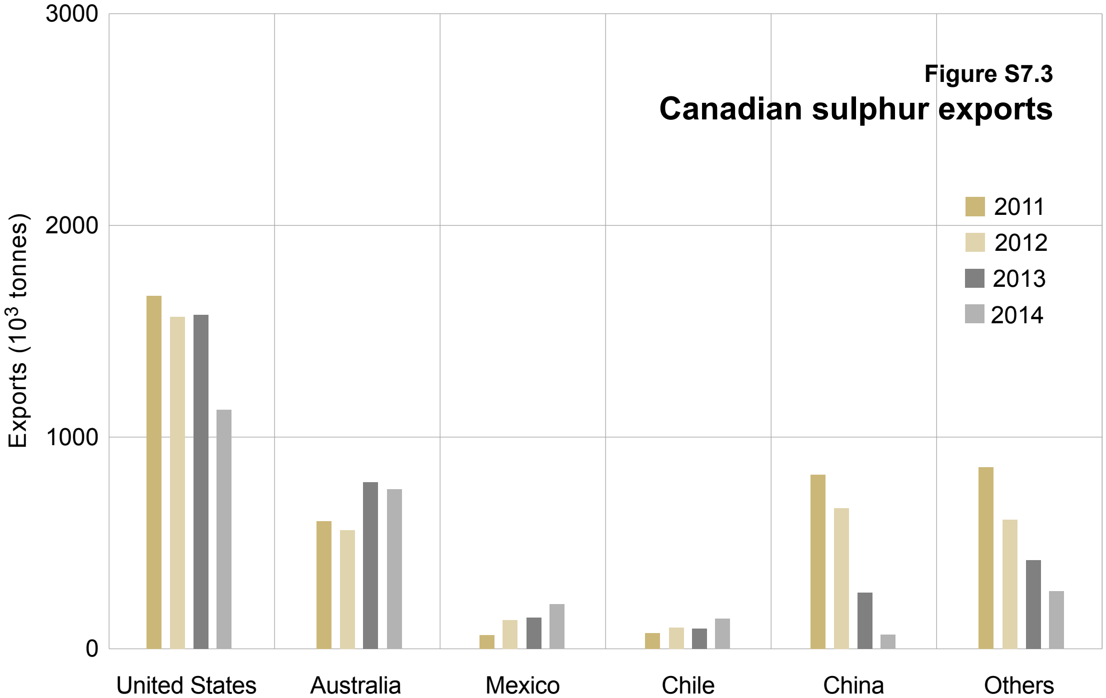


Figure S7.3
Canadian sulphur exports

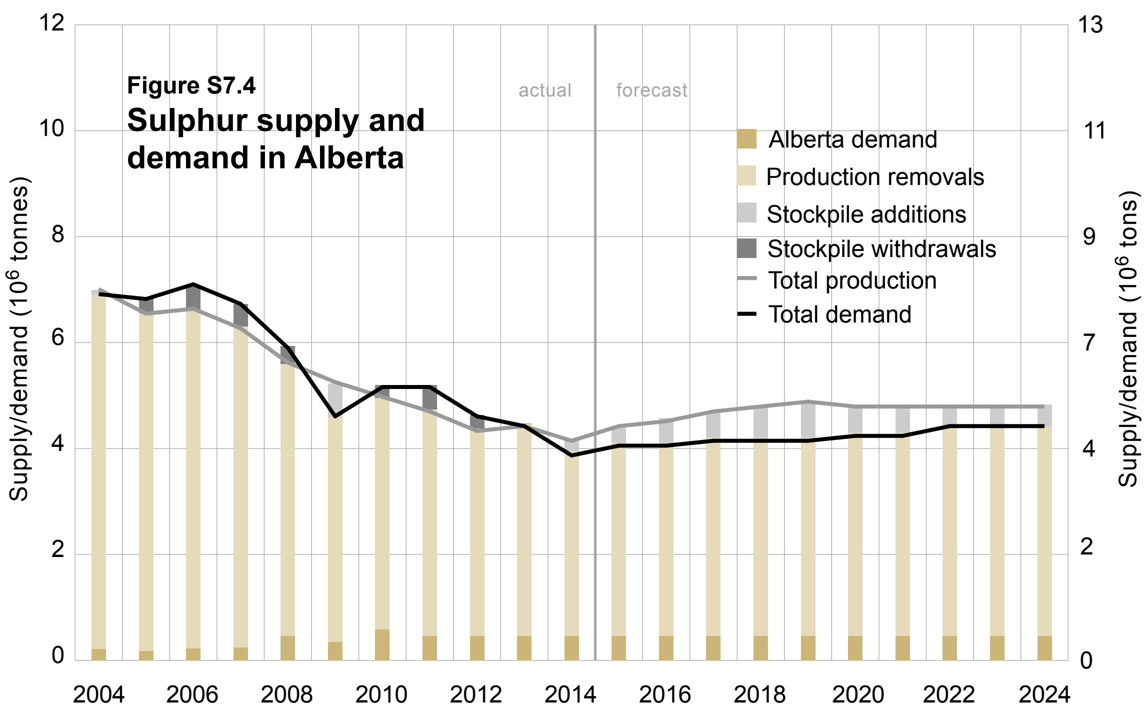


Figure S7.4
Sulphur supply and demand in Alberta

HIGHLIGHTS

Remaining established reserves under active development decreased slightly in 2014 due to production but still represent decades of supply.

Overall coal production was 2 per cent higher in 2014. Metallurgical bituminous and subbituminous coal production increased 15 per cent and 5 per cent, respectively, while thermal bituminous coal production decreased 32 per cent.

Alberta's total marketable coal production is expected to decrease about 6 per cent by 2024 to 28.0 megatonnes.

8 COAL

Coal is a combustible sedimentary rock with greater than 50 per cent organic matter. Coal occurs in many formations across central and southern Alberta, with lower-energy-content coals in the plains region and higher-energy-content coals in the foothills and mountain regions.

Production of coal from mines is called raw coal. Some coal, particularly that from the mountain and foothills regions of Alberta, needs to be processed before it is marketed; this processed coal is referred to as clean coal. Clean coal (normally sold internationally) and raw coal from the plains region (normally sold within Alberta) are called marketable coal. In this report, reserves refer to raw coal unless otherwise noted.

The possible commercial production of synthetic gas from coal (synthetic coal gas) in Alberta is still being investigated, and legislation is in place for regulating in situ coal gasification (ISCG) development. ISCG is discussed in **Section 8.1.2.3**.

The following coal reserves and production information summarizes and nominally updates the material found in the AER serial publication *ST31: Reserves of Coal, Province of Alberta* (2000 edition). See *ST31* for more detailed information and a greater understanding of the parameters and procedures used to calculate established coal reserves.

8.1 Reserves of Coal

8.1.1 Provincial Summary

The AER estimates the remaining established reserves of all types of coal in Alberta as of December 31, 2014, to be 33.2 gigatonnes (Gt; 10^9 tonnes) (36.6 billion tons). Of this amount, 22.7 Gt (or about 68.3 per cent) is considered recoverable by underground mining methods and 10.5 Gt is recoverable by surface mining methods. Of the total remaining established reserves, less than 1 Gt is within permit boundaries of mines active in 2014. **Table R8.1** gives a summary by rank of resources and reserves from 244 coal deposits.

Minor changes in remaining established reserves from December 31, 2013, to December 31, 2014, resulted from additions to cumulative production. During 2014, the low- and medium-volatile bituminous, high-volatile bituminous, and subbituminous production tonnages were 0.006 Gt, 0.005 Gt, and 0.024 Gt, respectively.

Table R8.1 Established initial in-place resources and remaining reserves of raw coal in Alberta as of December 31, 2014 (Gt)[a]

Rank Classification	Initial in-place resources	Initial reserves	Cumulative production	Remaining reserves
Low- and medium-volatile bituminous[b]				
Surface	1.74	0.811	0.258	0.553
Underground	5.06	0.738	0.114	0.624
Subtotal[c]	**6.83**	**1.56**	**0.372**	**1.19**
High-volatile bituminous				
Surface	2.56	1.89	0.214	1.68
Underground	3.30	0.962	0.0470	0.915
Subtotal[c]	**5.90**	**2.88**	**0.261**	**2.62**
Subbituminous[d]				
Surface	13.6	8.99	0.895	8.10
Underground	67.0	21.2	0.068	21.13
Subtotal[c]	**80.7**	**30.3**	**0.963**	**29.3**
Total[c]	**93.7**	**34.8**	**1.60[e]**	**33.2**

[a] Tonnages have been rounded to three significant digits.
[b] Includes minor amounts of semi-anthracite.
[c] Totals for resources and reserves are not arithmetic sums but are the result of separate calculations.
[d] Includes minor amounts of lignite.
[e] Any discrepancies are due to rounding.

8.1.2 In-Place Resources

The AER estimates the initial in-place resource of coal to be 93.7 Gt, of which the largest component, 80.7 Gt, is the subbituminous coal of the plains region. Most of this subbituminous coal exists at depths greater than 60 metres (m) but less than 600 m.[1] There is significant additional resource potential for coal within Alberta, as discussed in **Section 8.1.4**.

8.1.2.1 Geology and Coal Occurrence

Coal occurs extensively in Alberta through the nonmarine units of the sequence of Jurassic- to Paleocene-aged formations. The coal-bearing formations underlie about 300 000 square kilometres—almost half of Alberta. **Figure R8.1** shows the subcrops of most of the coal-bearing formations, and their equivalents, in Alberta.

Coal, with or without thin clastic layers called partings, occurs in layered accumulations called seams. Coal maturity, or rank, is measured on the basis of calorific value for lower ranked coals and carbon content for higher ranked coals. Coals of all rank groups, from lignite to semi-anthracite, occur in Alberta.

[1] Coal is known to exist below a depth of 600 m; however, it is beyond what is considered potentially mineable.

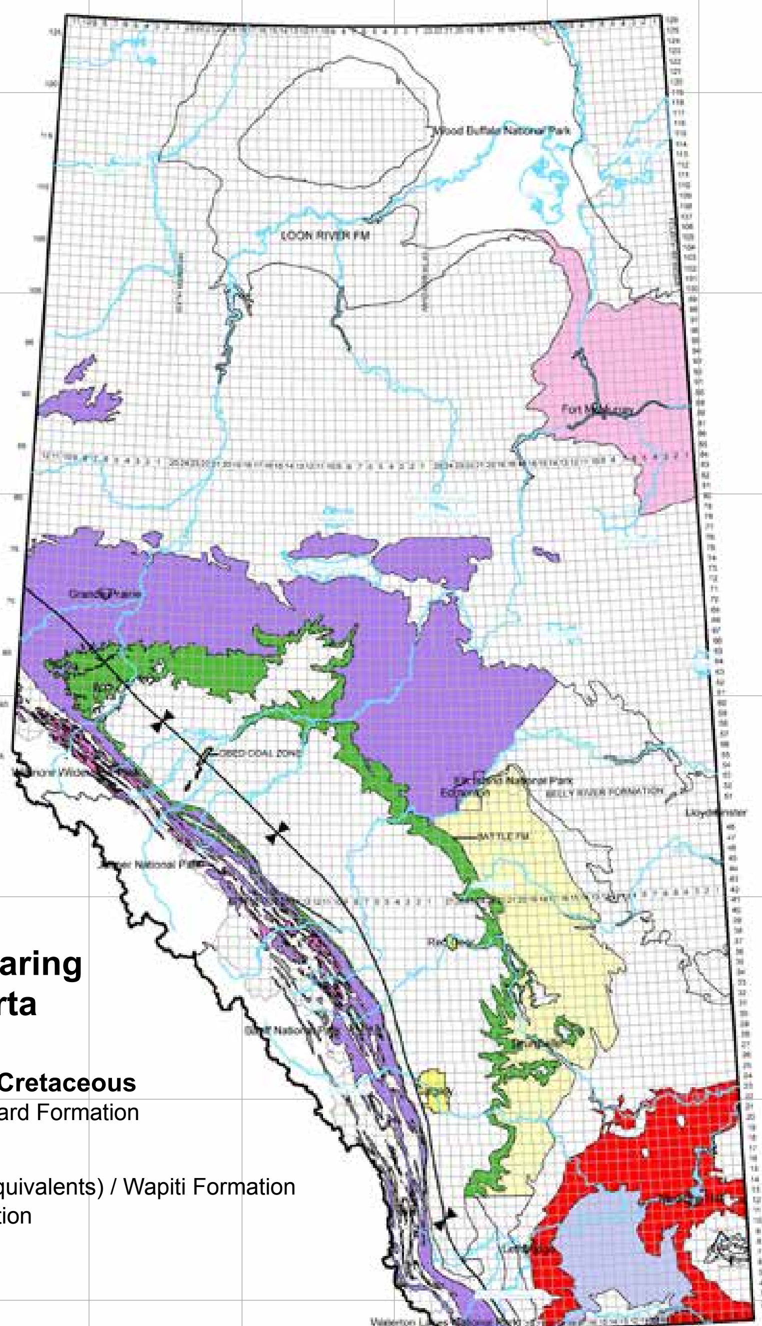


Figure R8.1

Significant coal-bearing formations in Alberta

Paleocene and Upper Cretaceous
- Coalspur Formation / Scollard Formation

Upper Cretaceous
- Brazeau Formation (and equivalents) / Wapiti Formation
- Horseshoe Canyon Formation
- Oldman Formation
- Foremost Formation

Lower Cretaceous
- Luscar Group
- Mannville Group

Lower Cretaceous and Upper Jurassic
- Kootenay Group

The AER has subdivided Alberta's coal-bearing regions into three designated regions (broadly shown in **Figure S8.1** in **Section 8.2.1**) based on rank, geology, and topography, so as to group coals by method of recovery and market. The mountain region exhibits complex geological structures and steep topography with higher ranked bituminous coal amenable to export for metallurgical purposes. The foothills region exhibits moderately complex geological structures and hilly topography with moderate-ranked bituminous coals amenable to export for thermal purposes. The plains region is the largest and exhibits generally flat-lying seams and flat or incised plateau topography with lower ranked coals amenable for domestic thermal purposes. The plains region contains about 88 per cent of Alberta's coal, most of which is subbituminous.

Figure R8.2 shows periods of exploration for coal in Alberta. Recent coal exploration has been predominately within areas where the AER has issued mine permits. While very significant coal resources were identified from holes drilled in the 1970s and 1980s, very few areas, other than currently producing areas, have seen follow-up drilling due to lack of markets.

8.1.2.2 Coal Mineability

In general, shallow coal is mined more economically by surface than by underground methods and is classified as surface mineable. At some stage of increasing depth and strip ratio,[2] the economic advantage passes to underground mining; this coal is considered underground mineable. The classification scheme used to differentiate between surface- and underground-mineable coal is very broadly based on depth and strip ratio and is designed to reflect relative costs, but it does not necessarily mean that the coal could be mined under the economic conditions prevailing today.

These classifications are used to categorize total coal in-place. Further analysis is done to determine which portions of this coal may be recovered. Some in-place coal, such as underground thin seams, is unlikely to be developed by mining methods but is included in the total because of past production. Additionally, some of the coal currently classified as underground may become the target of commercial ISCG development. If this becomes the case, the AER will split the underground classification into mineable and in situ components.

8.1.2.3 In Situ Coal Gasification

There are two main types of coal gasification processes: ISCG and surface-facility gasification from mined coal. Surface-facility gasification processes conventionally mined coal, and these mineable coal reserves have not been included in **Table R8.1** as Alberta does not have any surface-gasification facilities.

ISCG uses wellbores to access coal seams at depth. ISCG thermally reduces coal to simpler hydrocarbons that can be produced up a wellbore. Currently, ISCG synthetic coal gas is limited to a small quantity. Therefore, neither synthetic coal gas volumes nor their associated coal resource tonnages have been included in this report. However, Alberta's vast quantities of coal could supply a large resource base should development prove commercial.

[2] The strip ratio is the amount of overburden that must be removed to gain access to a unit amount of coal.

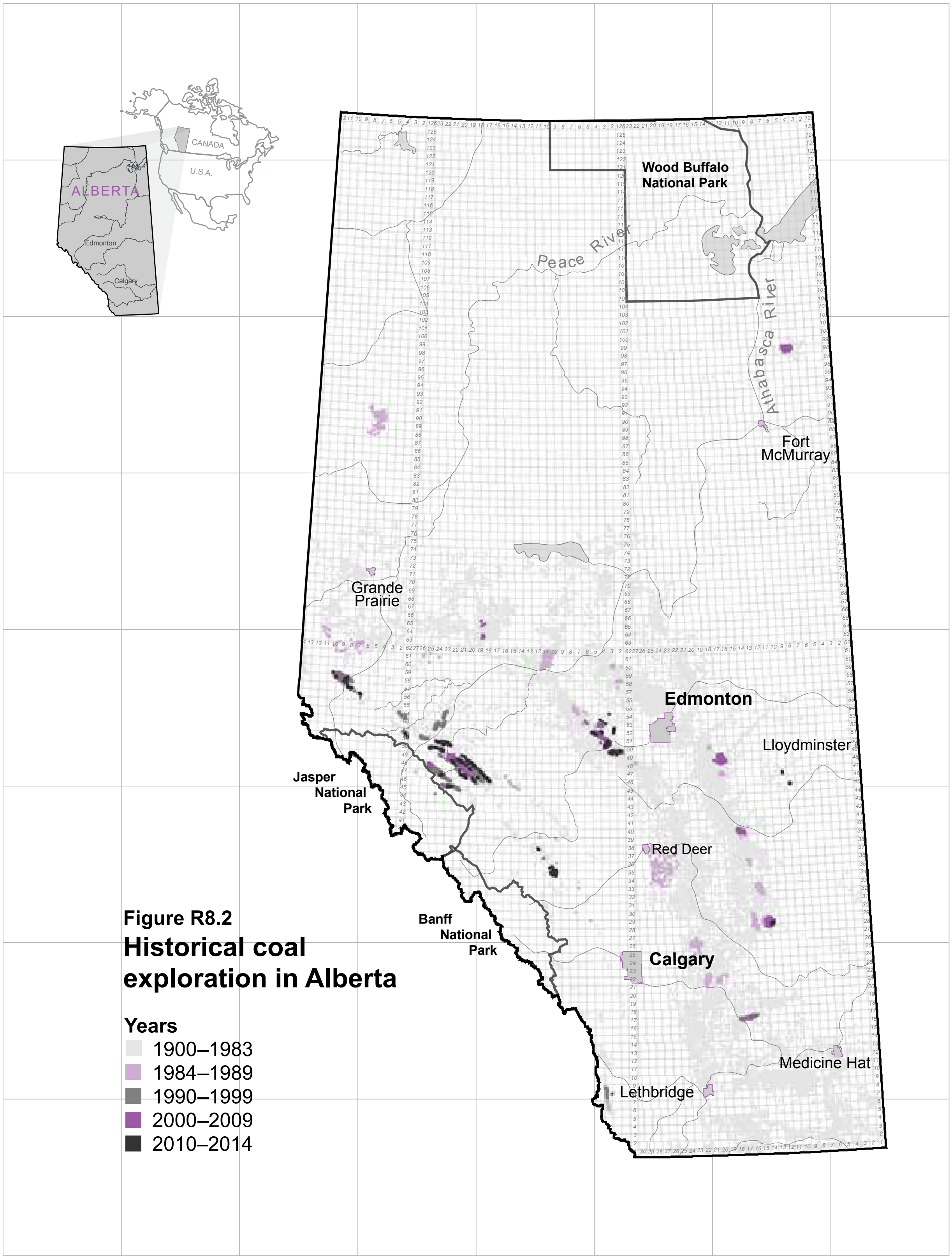


Figure R8.2
Historical coal exploration in Alberta

Two ISCG pilot projects have been approved but neither was operational in 2014. Future ISCG development may take place at depths below those currently assumed to be mineable.

8.1.3 Established Reserves

Several techniques, geostatistical methods in particular, have been used to calculate in-place volumes, with separate volumes calculated for surface- and underground-mineable coal. Certain parts of deposits are considered nonrecoverable for technical, environmental, economic, or safety reasons and, therefore, have no recoverable reserves. For the remaining areas, recovery factors have been determined for the surface-mineable coal and the thicker underground classes of coal seams.

A recovery factor of 90 per cent has been assigned to the remaining in-place surface-mineable area, followed by an additional small coal loss at the top and a small dilution at the bottom of each seam.

In the case of underground-mineable coal, geologically complex environments may make mining significant parts of some deposits uneconomic. Because the information to outline these areas is seldom sufficient, it is assumed that, in addition to the coal previously excluded, only a portion of the remaining deposit areas would be mined. Therefore, a deposit factor has been determined whereby, on average, only 50 per cent of the remaining deposit area is considered mineable in the mountain region, 70 per cent mineable in the foothills, and 90 per cent mineable in the plains—the three regions in Alberta designated by the AER where coals of similar quality and mineability are recovered.

A mining recovery factor of 75 per cent is then applied to both medium (1.5 to 3.6 m) and thick (>3.6 m) seams, with a maximum recoverable thickness of 3.6 m applied to thick seams. Thin seams (0.6 to <1.5 m) are not currently considered recoverable by underground methods.

Table R8.2 shows the established resources and reserves within the current permit boundaries of those mines active (either producing or under construction) in 2014. In 2013, the Obed Mountain Mine (Obed) operation was suspended. In February 2014, Coalspur Mines (Operations) Limited (Coalspur) received approval from the AER for its Vista Coal Project near Hinton. This mine project will be included in **Table R8.2** and **Figure S8.1** once production or significant construction starts.

8.1.4 Ultimate Potential

A large degree of uncertainty is associated with estimating an ultimate potential and new data could substantially alter results. Two methods have been used to estimate the ultimate potential of coal: volumetric and trend analysis. The volumetric method gives a broad estimate of the area, coal thickness, and recovery ratio for each coalbearing horizon, while the trend analysis method estimates the ultimate potential from the trend of initial reserves versus exploration effort.

To avoid large fluctuations in ultimate potential from year to year, the AER has adopted a policy of using the figures published in the 2000 edition of *ST31* and adjusting them slightly to reflect the most recent trends.

Table R8.2 Established resources and reserves of raw coal under active development as of December 31, 2014

Rank Mine	Permit area (ha)[a]	Initial in-place resources (Mt)[b]	Initial reserves (Mt)	Cumulative production (Mt)	Remaining reserves (Mt)[c]
Low- and medium-volatile bituminous					
Cheviot	7 455	246	154	33	121
Grande Cache	4 250	199	85	40	45
Subtotal[c]	**11 705**	**445**	**239**	**71**	**166**
High-volatile bituminous					
Coal Valley	17 865	572	331	170	161
Obed	7 590	162	137	46	91
Subtotal[c]	**25 455**	**734**	**468**	**216**	**252**
Subbituminous					
Paintearth	5 120	163	121	108	13
Sheerness	7 000	196	150	98	52
Dodds	425	2.0	2.0	1.7	0.4
Burtonsville Island	150	0.5	0.5	0.2	0.3
Highvale	12 140	1 021	764	434	330
Genesee	7 320	250	176	100	76
Subtotal[c]	**32 155**	**1 633**	**1 214**	**741**	**472**
Total[c]	**69 315**	**2 812**	**1 921**	**1 093**	**827**

[a] ha = hectares.
[b] Mt = megatonnes; mega = 10^6.
[c] Any discrepancies are due to rounding.

Table R8.3 gives quantities by rank for surface- and underground-mineable ultimate in-place resources, as well as the ultimate potential. No change to ultimate potential has been made for 2014.

8.2 Supply of and Demand for Marketable Coal

Alberta produces three types of marketable coal: subbituminous, metallurgical bituminous (commonly known as coking coal), and thermal bituminous (also referred to as steaming coal). Subbituminous coal is found across the plains region of the province and is suitable for power production and domestic heating; low- and medium-volatile ranked bituminous coals are located in the mountain region and are typically used for metallurgical purposes after processing; and high-volatile ranked bituminous coal is mainly located in the province's foothills region and is generally used as high-grade thermal coal after processing.

Subbituminous coal is mainly used to generate electricity in Alberta and is expected to be adversely affected by emerging environmental standards. Metallurgical bituminous coal is exported and used for industrial applications, such as steel production. Thermal bituminous coal is primarily exported and used to fuel electricity generators

Table R8.3 Ultimate in-place and potential resources (Gt)[a]

Coal rank Classification	Ultimate in-place	Ultimate potential
Low- and medium-volatile bituminous		
Surface	2.7	1.2
Underground	18	2.0
Subtotal	**21**	**3.2**
High-volatile bituminous		
Surface	10	7.5
Underground	490	150
Subtotal	**500**	**160**
Subbituminous		
Surface	14	9.3
Underground	1 400	460
Subtotal	**1 500**	**470**
Total	**2 000[b]**	**620**

[a] Tonnages have been rounded to two significant digits. Totals are not arithmetic sums but are the result of separate calculations.
[b] Work done by the Alberta Geological Survey suggests that the value is likely significantly larger.

in distant markets. The higher calorific content of Alberta's thermal bituminous coal makes it possible to economically transport the coal over long distances.

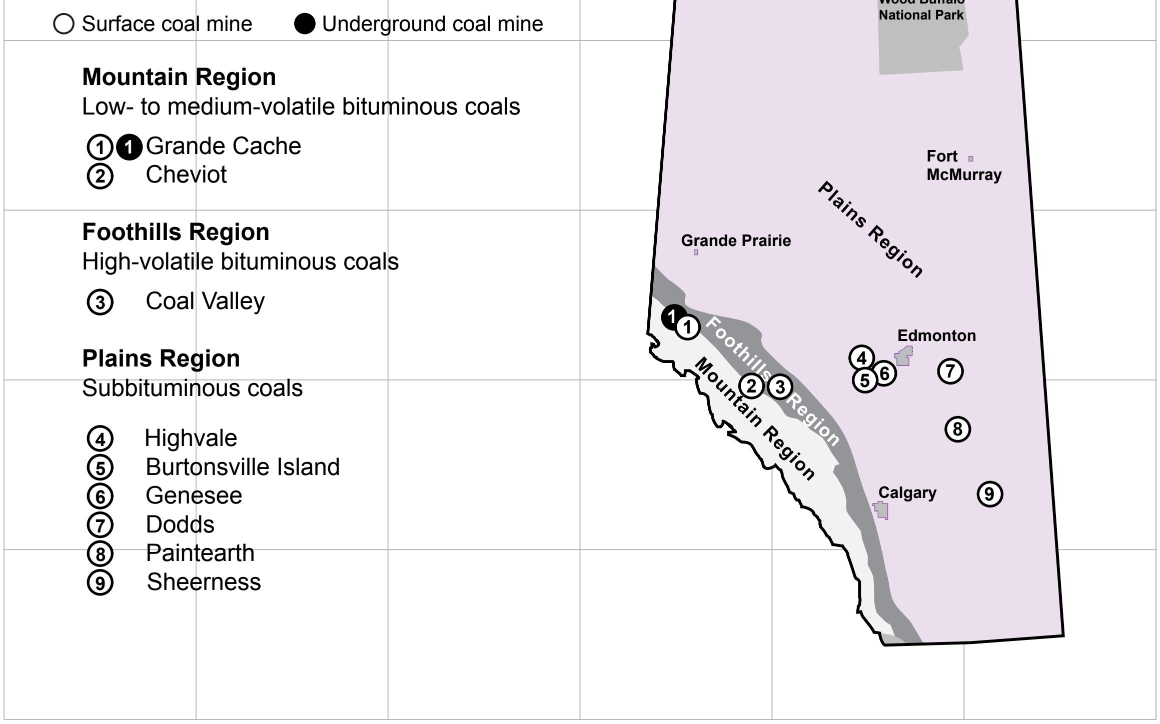
While subbituminous coal is burned without any form of upgrading, both types of export coal are sent in raw form to a preparation plant, whose output is referred to as clean coal. On average, about 65 per cent of raw metallurgical bituminous coal and less than 50 per cent of raw thermal bituminous coal is recovered as clean coal in Alberta. Subbituminous raw coal and both types of clean bituminous coal are collectively known as marketable coal.

8.2.1 Coal Production – 2014

The locations of coal mine sites in Alberta are shown in **Figure S8.1**. In 2014, nine mine sites produced coal in Alberta, as shown in **Table S8.1**. These mines produced 29.6 megatonnes (Mt) of marketable coal. Subbituminous coal accounted for 81.2 per cent of the total, metallurgical bituminous coal 11.2 per cent, and thermal bituminous coal the remaining 7.6 per cent. **Table S8.2** shows the change in coal production over the past year.

In 2014, metallurgical bituminous and subbituminous coal increased by 15.1 and 5.1 per cent, respectively. Thermal bituminous coal production decreased by 32.0 per cent due to reduced output from the Coal Valley Mine and suspended operations at the Obed Mountain Mine. Overall, total marketable production of coal increased by 1.9 per cent from 2013.

Figure S8.1
Producing coal mines in Alberta in 2014



Six surface mines produced subbituminous coal in 2014. Most mines serve nearby electric power plants, while a few mines supply residential and commercial customers. Because of the need for long-term supply of coal to power plants, most of the subbituminous reserves are dedicated to fuelling power plants.

Two surface mines and one mine with both surface and underground recovery produce the provincial supply of metallurgical and thermal bituminous coal. The Obed Mountain Mine suspended production in 2014 and has been removed from **Figure S8.1**.

In early 2014, the AER approved Coalspur's Vista project located near Hinton. Australian-based Coalspur planned to export thermal coal from the project overseas by 2016. However, in mid-2014, Coalspur delayed construction due to low global thermal coal prices. The company was later acquired by KC Euroholdings in early 2015.

Benga Mining Ltd, a subsidiary of Australia's Riversdale Resources, plans to submit all necessary applications for its Grassy Mountain project by mid-2015. The intent of this multiphased project is to explore metallurgical coal deposits in the Crowsnest Pass area and to produce coking coal for shipments overseas. Pending regulatory approval, the company has announced plans to begin construction in 2017, with the mine beginning operations in 2018.

Table S8.1 Alberta coal mines and marketable coal production in 2014

Owner (grouped by coal type)	Mine	Location	Production (Mt)
Subbituminous coal			
Capital Power GP Holdings Inc.	Genesee	Genesee	4.9
Prairie Mines and Royalty Ltd.	Sheerness	Sheerness	3.0
	Paintearth	Halkirk (Cordel)	2.7
TransAlta Corporation	Highvale	Wabamun	13.4
Dodds Coal Mining Co. Ltd.	Dodds	Ryley	0.1
Keephills Aggregate Co. Ltd.	Burtonsville Island	Burtonsville Island	0.01
Subtotal[a]			**24.1**
Metallurgical bituminous coal			
Teck Resources Limited	Cheviot	Mountain Park	1.8
Grande Cache Coal Corp.	Grande Cache	Grande Cache	1.5
Subtotal[a]			**3.3**
Thermal bituminous coal			
Coal Valley Resources Inc.	Coal Valley	Coal Valley	2.2
	Obed	Obed	0.0
Subtotal[a]			**2.2**
Total[a]			**29.6**

[a] Any discrepancies are due to rounding.

Table S8.2 Marketable coal production and change highlights (Mt)

	2014	2013	Change	Change (%)[a]
Subbituminous	24.1	22.9	+1.2	+5.1
Metallurgical bituminous	3.3	2.9	+0.4	+15.1
Thermal bituminous	2.2	3.3	-1.1	-32.0
Total	**29.6**	**29.1**	**+0.5**	**+1.9**

[a] Per cent changes are based on annual production volumes.

8.2.2 Coal Production – Forecast

The projected production for each of the three types of marketable coal is shown in **Figure S8.2**. Total production is expected to decrease over the forecast period by 5.7 per cent, from 29.6 Mt in 2014 to 28.0 Mt by 2024. The decline in total marketable coal production is attributed to expected declines in subbituminous production (which makes up the greatest portion of overall marketable coal) and metallurgical bituminous output. With the anticipated retirement of coal-fired electricity generators, subbituminous coal output is expected to decrease by 5.8 per cent, from 24.1 Mt in 2014 to 22.6 Mt by 2024.

Compared to the 3.3 Mt of output produced in 2014, metallurgical bituminous coal production is expected to decrease by 30.7 per cent by 2024. The AER expects metallurgical coal to average 2.3 Mt over the forecast period. The decline is primarily attributed to Grande Cache's decision to suspend surface operations and to the declining output from its underground mine.

Relative to the 2.2 Mt reported in 2014, production of thermal bituminous coal is expected to recover in 2015 and remain stable at 3.0 Mt over the remainder of the forecast period as exports meet international demands for fuel used to generate power. Producers of both types of bituminous coal will continue to be challenged in the near term, with increasing international competition and continued low market prices.

Based on existing information, production from the pending Vista and Grassy Mountain projects have not been included in this year's forecast due to the uncertainty of their future economic and regulatory statuses. An increase in the production of both metallurgical and thermal coal is possible if updates become available on these two projects, in addition to any other projects that may arise over the forecast period.

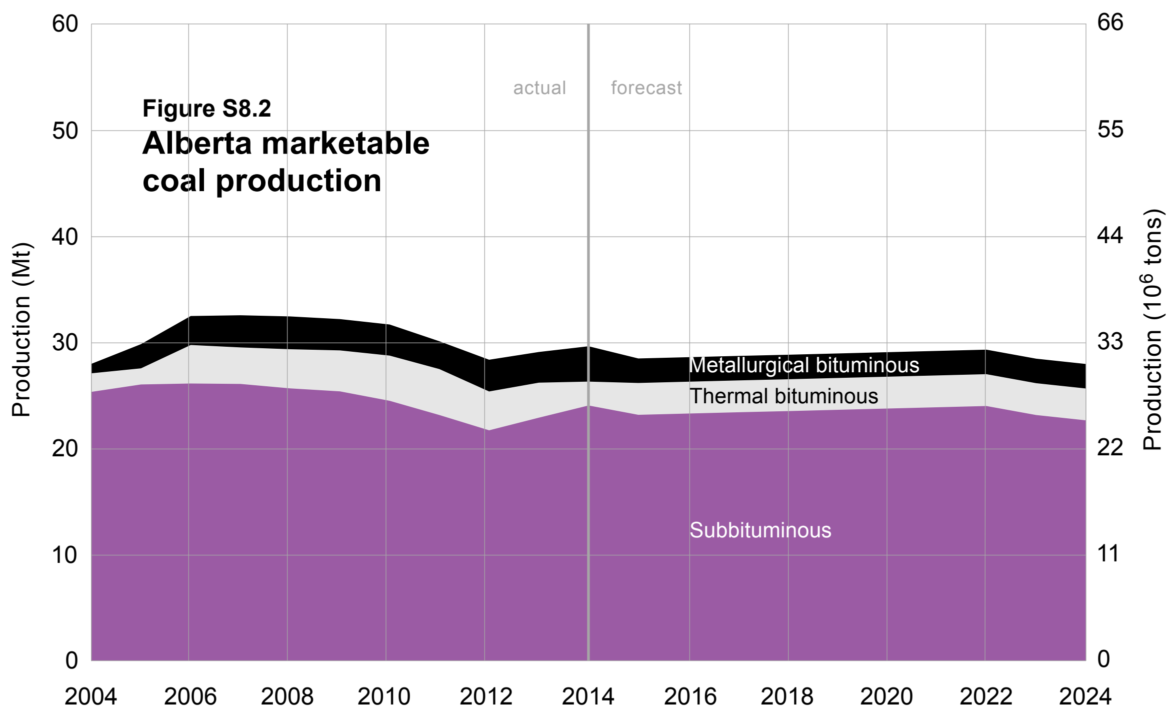


Figure S8.2
Alberta marketable coal production

8.2.3 Coal Demand

8.2.3.1 Subbituminous Coal

In Alberta, mines producing subbituminous coal primarily serve Alberta's coal-fired electricity generation plants. Less than one per cent of the remaining demand for subbituminous coal comes from residential, commercial, and industrial users who rely on it for heating purposes. Since subbituminous coal mines predominately supply coal-fired generation plants, production will be considerably affected by the closures of existing facilities in favor of constructing new natural gas power producing stations.

According to the Alberta Electric System Operator's (AESO) *2014 Annual Market Statistics*, coal-fired generation has historically supplied nearly 70 per cent of the total power delivered to the province's electric system. Although a trend over the past five years has shown that coal is slowly decreasing in proportion to the total output of all generation technologies, coal has maintained a prominent position in the Power Pool of Alberta[3] through its role as a low marginal cost base-load generator. Despite the total installed capacity of natural gas technologies (e.g., cogeneration, combined-cycle, and simple-cycle generators) surpassing coal-fired capacity for the first time in 2014, coal continues to remain the majority source of power production in Alberta.

Demand for Alberta's subbituminous coal is expected to decline in 2015 with the addition of natural gas-fired generators supplying electricity to the Power Pool of Alberta, notably Enmax Corporation's 872 megawatt (MW) Shepard Energy Centre. Demand for subbituminous coal is forecast to begin to modestly increase in 2016 and continue until 2022 to fulfill base load on Alberta's growing electricity grid. Demand will then begin to taper off by 2024 as coal-fired power generators are decommissioned.

In 2012, the federal government issued new regulations that require all coal-fired power plants to either be retired by the end of their economic life (after 50 years of operation) or meet stringent emissions requirements. These regulations are published as the *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations* and are scheduled to come into effect in July 2015.

Based on these federal rules, coal-fired generators that came on line before 1975 will reach their end-of-useful life either after 50 years of operational service or by the end of 2019, whichever comes first. Plants commissioned between 1975 and 1986 will face similar rules, with their maximum termination date coming at the end of 2029. Facilities that commenced operations after 1986 will have 50 years to produce power.

Both old and new coal-fired facilities can apply until 2025 to be retrofitted with carbon capture and storage (CCS) technology to remain operational beyond their scheduled retirement dates. The addition of CCS to coal-fired plants is intended to reduce emissions to a level on par with natural gas combined-cycle generators. The AER has considered the effect of coal-fired generator retirements in its demand forecast, including the high capital costs and current economic uncertainty of CCS equipment. Despite steady growth expected in the near term for

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[3] Producers make offers to supply electricity into the Power Pool of Alberta, which functions as an open-access spot market to determine an hourly pool price. These competitive bids are then dispatched on a merit order from lowest to highest costs to meet demand.

Alberta's subbituminous coal, overall demand is anticipated to decrease by the end of the forecast period due to the anticipated retirement of several coal-fired generators.

Considering that the average age of operational coal-fired generators in 2014 was about 31 years, four coal-fired generators are at risk of shutting down within the forecast period if they are unable to economically incorporate CCS to meet the federal regulations. After five decades of service that began in 1969, ATCO Power's 152 MW Battle River Unit 3 is on schedule to retire in 2019. TransAlta Corporation's 288 MW Sundance Unit 1 and 288 MW Sundance 2 will reach their end-of-useful lives in 2020. The 144 MW HR Milner Generating Station will also be subject to shutting down in 2020. Based on the installed generation capacities reported by AESO in 2014, these four coal-fired generators currently represent about 13.9 per cent of the total coal capacity at 6271 MW, and 5.4 per cent of the total system capacity at 16 151 MW.

8.2.3.2 Metallurgical Bituminous Coal

Alberta's metallurgical coal primarily serves the iron and steel smelting industry. Japan, South Korea, and Brazil were the leading importers of the province's metallurgical coal in 2014. China dropped from being second in 2013 to fourth in 2014. Total metallurgical deliveries decreased by 2.0 per cent in 2014 from 2013.

Metallurgical bituminous exports to China decreased substantially in 2014. In an effort to reduce pollution and stabilize the county's coal industry, the Chinese government restricted the importation and local sales of lower-grade coal. These policies are expected to have a considerable effect on the demand for Australian and Indonesian bituminous coal; however, Alberta's relatively higher quality coal is currently within the ash and sulphur content constraints mandated by the Chinese government, which shows promise towards sustaining a market for the province's deliveries.

Although South Korea, Brazil, and Finland have grown significantly as export markets for Alberta coal, the long distance required to transport coal from mine to port creates a competitive disadvantage for Alberta's export-coal producers. Coal export terminals have made significant investments in recent years to increase throughput capacities to meet growing supplies of coal from western Canada and the United States that is destined for foreign markets.

8.2.3.3 Thermal Bituminous Coal

Alberta's thermal bituminous coal is predominately exported abroad for power production, with 93.9 per cent of thermal coal directed to markets outside the province in 2014. Japan continued to import the most thermal coal from Alberta in 2014, while Brazil ranked second, and China third.

Following the Fukushima Daiichi incident in March 2011, all 48 of Japan's nuclear plants were shut down and the country increased its reliance on fossil fuels, including imported thermal bituminous coal, to sustain power generation. The Japanese government voiced its support in November 2014 for a restart of the first reactors beginning in June 2015. Despite the pending resurgence of nuclear power, demand for imported thermal bituminous coal is expected to remain stable over the next decade, with higher cost fuel oil being initially phased out. Compounded by mounting costs to retrofit and enhance safety on existing nuclear plants, relatively less expensive coal-fired generation is expected to remain strong over the next decade with the upcoming deregulation of Japan's power market.

Thermal bituminous coal exports from the province decreased by 11.9 per cent in 2014 from 2013 levels. The reduction in demand over 2014 is attributed to significant decreases in deliveries to Brazil and South Korea, which was further compounded by a lessened thermal bituminous supply. The decrease in exports to these two countries greatly outweighed the aggregate positive year-over-year change in deliveries made to China, Taiwan, and the United States.

Thermal coal prices are anticipated to remain low as producers look to capture greater international market shares and undercut competition, a downward trend which has persisted since 2011. Similar to Canada, the Environmental Protection Agency's *Mercury and Air Toxics Standards* in the United States has moved to reduce emissions associated with coal-fired power production. American exports of thermal bituminous coal are expected to moderately increase in the near term as coal's role in American electricity generation wanes in favor of abundant and cleaner burning natural gas. In addition to North America's buildup of surplus coal supplies, Australia's decision to repeal its carbon tax in 2014 also has the potential to stimulate the nation's bituminous coal production and seaborne exports in the upcoming years.

9 INFRASTRUCTURE

The infrastructure needed to support the development of Alberta's vast energy resources involves networks of oil and gas pipelines, railroad lines, roads and highways, and electricity transmission lines. This infrastructure also includes facilities that turn raw natural resources into marketable energy products that travel through pipelines and on railroads and trucks to distribution outlets for purchase. Alberta's energy resource infrastructure allows secure and stable access to energy, which helps meet the needs of commercial, residential, and industrial consumers. **Figure 9.1** illustrates Alberta's energy resource production and the infrastructure involved to produce both raw and marketable energy and non-energy products used by Alberta consumers and external markets.

HIGHLIGHTS

The Vantage pipeline was commissioned in June 2014 and delivers ethane from North Dakota.

The western leg of the Cochin pipeline was reversed to supply condensate from the United States to Alberta.

The AER regulates about 415 000 kilometres of pipelines in Alberta.

9.1 Energy Commodity Transportation

Thousands of kilometres of transportation infrastructure are needed to move Alberta's energy resource commodities from where they are produced to where they are consumed, both inside and outside Alberta. A network of pipelines has been built solely to transport energy resources. Other infrastructure, such as railroads, roads, and electrical lines, is shared with other industries and individual Albertans.

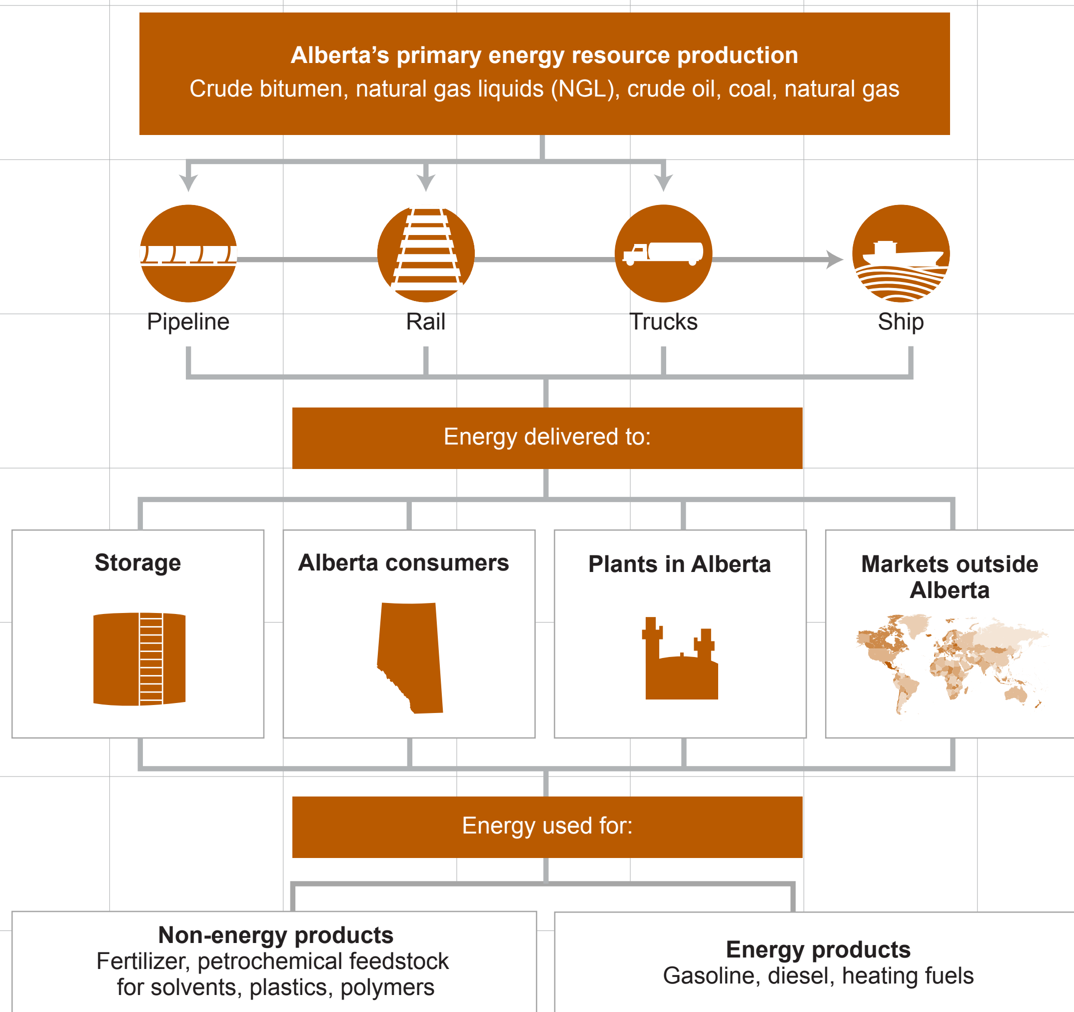
9.1.1 Pipelines

Over 415 000 kilometres (km) of pipeline in Alberta are regulated by the AER, which includes about 11 500 km of Alberta Utilities Commission (AUC) natural gas utility pipelines that the AER conducts surveillance and inspections, incidence response, and failure investigations on through a memorandum of understanding. Interprovincial pipelines are regulated by the National Energy Board (NEB) and include about 73 000 km across Canada.

Alberta's intraprovincial pipeline system is highly integrated and includes gathering, transmission, and distribution lines that transport hydrocarbons from the field to major distribution and processing centres that operate within the province's borders. Removal pipelines are typically long distance, higher capacity pipelines that carry hydrocarbons to ex-Alberta markets. Removal pipelines link Alberta to markets in the rest of Canada and the United States.

Most pipelines in Alberta are relatively small, with an outside diameter of 168.3 millimetres (mm) or smaller, and carry production from individual wells to nearby processing facilities. Large-diameter transmission lines 508 mm or more in outside diameter make up 2.5 per cent of the AER's total regulated inventory.

Figure 9.1
Schematic of Alberta energy resource flow



9.1.1.1 Crude Oil and Bitumen Pipelines

Current and proposed pipeline infrastructure play a key role in moving Alberta's growing supply of oil bitumen to markets both inside and outside of the province. Throughout this section, both crude oil and crude bitumen will simply be referred to as oil.

To keep up with the rise in production in Alberta, pipeline companies have announced several intraprovincial and removal pipeline projects designed to help expand capacity in the province and to reach new markets. Midstream companies are also working towards expanding natural gas liquid (NGL) infrastructure in the province to ensure the stable supply of pentanes plus (a diluent for bitumen blending) and ethane (a primary feedstock for the petrochemical sector).

Within the province, the construction of new pipelines and expansion of existing pipelines will ensure that projects have access to traditional hubs in Edmonton and Hardisty and producers have access to ex-Alberta markets.

Table 9.1 shows existing major intraprovincial oil pipelines in Alberta in 2014. A number of additional intraprovincial pipelines have been planned or announced.

Table 9.1 Alberta's intraprovincial oil pipelines

Name	Destination	Capacity (10^3 m^3/d)
Access Pipeline Inc.		
Access pipeline	Edmonton	23.8
Canadian Natural Resources Limited		
Echo pipeline	Hardisty	12.0
Enbridge Inc.		
Athabasca pipeline	Hardisty	54.8
Waupisoo pipeline	Edmonton	87.4
Husky Energy Inc.		
Husky pipeline	Hardisty; Lloydminster	78.0
Inter Pipeline Fund		
Cold Lake pipeline	Hardisty; Edmonton	103.3
Corridor pipeline	Edmonton	73.9
Pembina Pipeline Corporation		
Horizon pipeline	Edmonton	39.7
Plains Midstream Inc.		
Rainbow pipeline	Edmonton	31.7
Suncor Energy Inc.		
Oil Sands pipeline	Edmonton	23.0
Syncrude Canada Ltd.		
Syncrude pipeline	Edmonton	61.8

Access Pipeline Inc. intends to twin its existing pipeline, with the new pipeline being capable of transporting 55.6 thousand (10^3) cubic metres per day (m^3/d). The line is scheduled to become operational in 2015.

Enbridge Inc. (Enbridge) also intends to expand its capacity to move bitumen from the Christina Lake region. To do this, it plans to expand the capacity of its Athabasca system, which moves product to the Hardisty Terminal. Additionally, Enbridge has announced that the Fort Hills pipeline system has been commercially secured, with construction to follow customer timing.

Inter Pipeline Limited (Inter Pipeline) has announced that it intends to proceed with an integrated expansion of its Cold Lake and Polaris pipeline systems.

Table 9.2 shows existing removal oil pipelines in Alberta in 2014. A number of additional removal pipelines have been planned or announced.

Enbridge plans to develop the Northern Gateway pipeline, which would see production move from Bruderheim, Alberta, to Kitimat, British Columbia. The pipeline would have a capacity of 83.3 10^3 m^3/d.

Kinder Morgan Canada (Kinder Morgan) has filed an application with the NEB to expand its TransMountain pipeline from 47.7 10^3 m^3/d to 141.4 10^3 m^3/d. Where possible, the expansion is planned to follow existing routing, running from Edmonton, Alberta, to tidewater on the west coast.

The northern leg of TransCanada Corporation's (TransCanada) Keystone XL project, pending approval, is expected to run from Hardisty, Alberta, to Steele City, Nebraska. The pipeline would have a capacity of 131.9 10^3 m^3/d.

Table 9.2 Alberta's removal oil pipelines

Name	Destination	Capacity (10^3 m^3/d)
Enbridge Inc.		
Enbridge pipeline	Eastern Canada U.S. East Coast U.S. Midwest	301.9
Alberta Clipper pipeline	U.S. Midwest	71.5
Kinder Morgan Canada		
Express pipeline	U.S. Rocky Mountains U.S. Midwest	44.9
Trans Mountain pipeline	British Columbia U.S. West Coast Offshore	47.7
Plains Midstream Canada		
Milk River pipeline	U.S. Rocky Mountains	18.8
Pacific Energy Partners, L.P.		
Rangeland pipeline	U.S. Rocky Mountains	13.5
TransCanada Corporation		
Keystone pipeline	U.S. Midwest	93.8

TransCanada filed an application in 2014 for the conversion of part of its Mainline system from natural gas to oil transmission. The converted pipeline, referred to as the Energy East project, would carry 174.8 10^3 m^3/d and would initially move oil from Alberta to eastern refiners.

Figure 9.2 shows a map of selected proposed removal pipeline expansions and new pipeline removal projects in North America. Additionally, **Table 9.3** summarizes information, such as timelines for and the capacity of proposed North American pipelines, that could play a key role in transporting Alberta oil. Market access and the issue of pipeline constraint and its effect on the Canadian oil market is discussed in **Section 3.2.4**.

9.1.1.2 Natural Gas Liquids Pipelines

The petrochemical industry in Alberta is the main consumer of ethane recovered from natural gas, with four ethylene plants using ethane as feedstock. Three of these plants are located at Joffre, Alberta, with the fourth located at Fort Saskatchewan. The Alberta Ethane Gathering System (AEGS) transports specification ethane to the Joffre and Fort Saskatchewan areas.

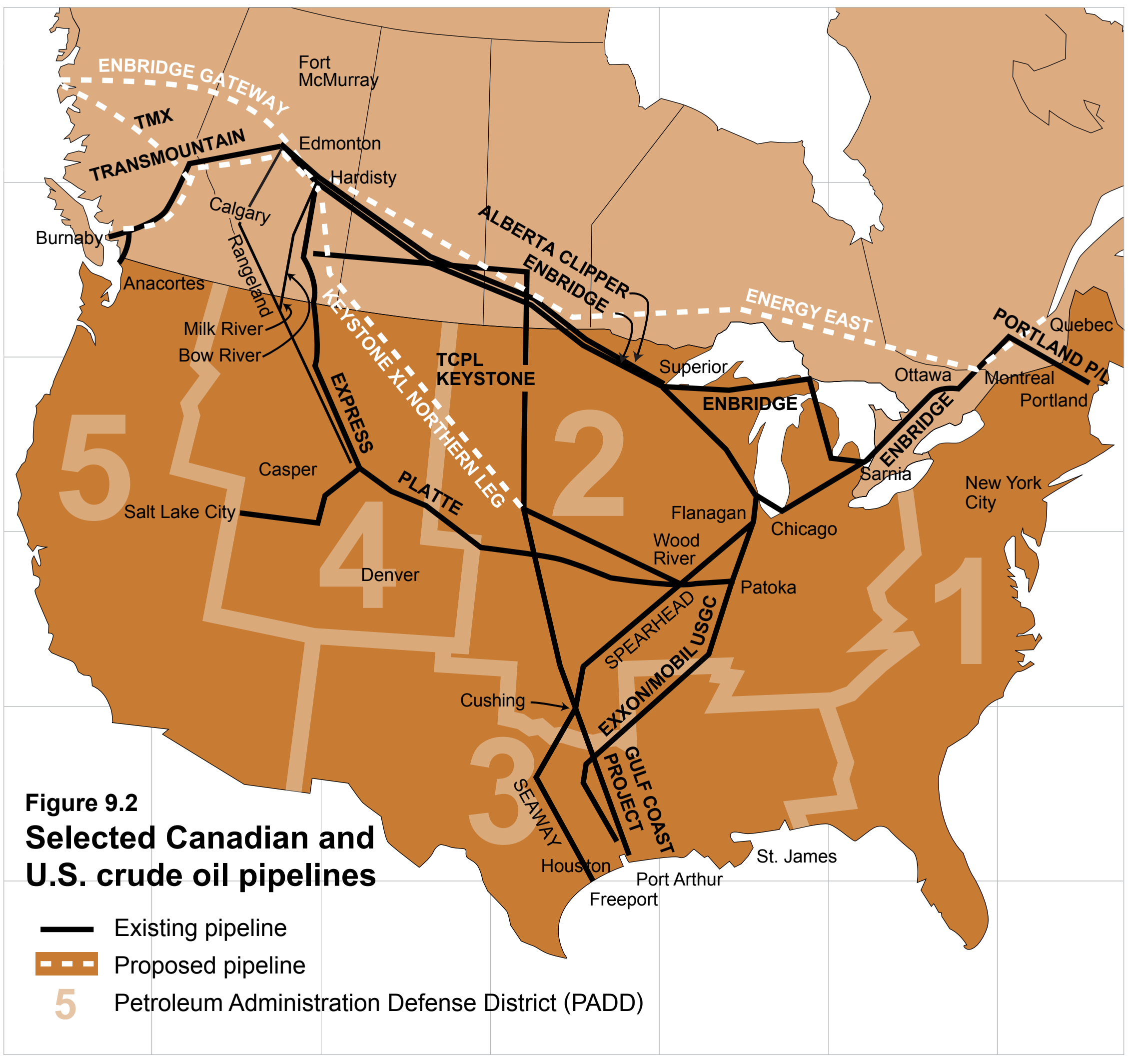


Figure 9.2
Selected Canadian and U.S. crude oil pipelines

Existing pipeline
Proposed pipeline
5 Petroleum Administration Defense District (PADD)

Table 9.3 Selected North American pipeline system developments

Company Project	Start-up	Capacity (10^3 m^3/d)	Origin	Destination
Enbridge				
Alberta Clipper Expansion Phase 2	2015	36.5	Hardisty, AB	Superior, WI
Southern Access Phase 2	2015	101.7	Superior, WI	Patoka, IL
Line 9A Reversal	TBD[a]	47.7	Sarnia, ON	Westover, ON
Line 9B Reversal	TBD	47.7	Westover, ON	Montreal, QC
Northern Gateway	TBD	83.4	Bruderheim, AB	Kitimat, BC
Kinder Morgan				
TransMountain Expansion	2017	141.4	Edmonton, AB	Vancouver, BC
TransCanada				
Energy East	TBD	174.8	Hardisty, AB	Montreal, QC
Keystone XL	TBD	131.9	Hardisty, AB	Steele City, NB

[a] To be determined.

Demand for pentanes plus has been exceeding Alberta supply since 2004, resulting in a reliance on the importation of pentanes plus for use as diluent. Alberta's imports of pentanes plus are expected to continue to increase over the next 10 years with growing demand from the oil sands. Currently, Alberta imports pentanes plus on trucks, rail cars, and pipelines.

Table 9.4 shows existing intraprovincial NGL pipelines in Alberta in 2014. A number of additional intraprovincial pipelines have been planned or announced.

Inter Pipeline's Polaris pipeline has completed the first phase of its expansion, and began providing diluent service to crude bitumen production facilities in northern Alberta. The company plans to increase the capacity on the Polaris pipeline from 9.5 10^3 m^3/d to 19.1 10^3 m^3/d by 2017. Keyera Corporation's (Keyera) Alberta Liquids pipeline system would allow producers to transport NGL mix and condensates from the Simonette/Edson area to Fort Saskatchewan. Keyera completed the pipeline in 2014.

Pembina Pipeline Corporation (Pembina) has also proposed the Phase III Expansion that would involve constructing a pipeline from Fox Creek, Alberta, to the Edmonton area. The pipeline would have an initial capacity of 50.9 10^3 m^3/d and an ultimate capacity of over 79.5 10^3 m^3/d once pump stations have been added. It has announced an in-service date of 2017.

Table 9.5 shows existing removal and import NGL pipelines in Alberta in 2014.

Pembina's Vantage pipeline was commissioned in June 2014 and delivers ethane from North Dakota and Saskatchewan to Southern Alberta. The pipeline has a capacity to deliver 6.4 10^3 m^3/d. In early 2015, Pembina announced plans to expand the Vantage pipeline system to increase its mainline capacity from 6.4 10^3 m^3/d to 10.8 10^3 m^3/d, subject to approvals, this expansion is projected to be in-service in 2016.

Table 9.4 Alberta's intraprovincial NGL pipelines

Name	Destination	Capacity (10^3 m^3/d)
Inter Pipeline Ltd.		
Polaris pipeline	Northern Alberta	9.5
Pembina		
Pembina pipeline	Gathering pipelines in south-central Alberta	23.8
Swan Hills pipeline	Edmonton	17.5
Mitsue pipeline	North of Slave Lake	7.2
Brazeau/Caroline pipelines	Edmonton	9.5
Cremona pipeline	Rangeland pipeline in southern Alberta	7.9
Bonnie Glen pipeline	Edmonton	15.9
Plains Midstream Canada		
Rainbow pipeline	Edmonton	35.0
Rangeland pipeline	Carway	7.9
Co-Ed pipeline system	Edmonton; Fort Saskatchewan	11.4
Veresen Inc.		
Alberta ethane gathering system	Petrochemical facilities in Alberta	51.2
Williams		
Boreal pipeline	Redwater	19.8

Table 9.5 Alberta's removal and import NGL pipelines

Name	Destination	Capacity (10^3 m^3/d)
Enbridge		
Southern Lights pipeline	Edmonton, AB	28.6
Kinder Morgan		
Cochin pipeline	Sarnia, ON	15.1
Pembina		
Peace and Northern NGL pipeline system	Fort Saskatchewan, AB	57.5
Liquids gathering system	Pembina Northern NGL pipeline system (Taylor, BC)	6.1
Vantage Pipeline		
Vantage pipeline	AEGS in southern Alberta	6.3

Kinder Morgan has reversed the western leg of its Cochin pipeline to supply condensate from Illinois to Fort Saskatchewan, Alberta, and is now importing condensate shipments to meet the growing demand from the oil sands industry.

Table 9.6 shows select North American NGL pipeline developments that have been identified as having the potential to affect the Alberta market.

9.1.1.3 Natural Gas Pipelines

Natural gas is transported from the wellhead by a gathering system to field processing plants. Field plants, typically located near the source of the gas upstream of the pipeline, ensure that natural gas meets the quality specifications of the natural gas pipeline systems, which may require removing NGLs to meet pipeline hydrocarbon dew point specifications. Removing other contaminants, such as water and hydrogen sulphide, is required. NGL extraction beyond what is needed to meet dew point specification may also occur, to obtain full value for the NGL components.

Once impurities are extracted and the natural gas meets pipeline specification, the natural gas is then compressed before being transported into a large transmission pipeline. Under compression, natural gas is able to flow through the transmission system from areas of high pressure to areas of low pressure. Once natural gas reaches end markets, local distribution companies reduce the pressure for local delivery distribution networks.

Table 9.7 shows existing intraprovincial natural gas pipelines in Alberta in 2014. No new major intraprovincial natural gas pipeline projects have been announced recently.

Table 9.8 shows existing removal and import natural gas pipelines in Alberta in 2014. No new major removal or import natural gas pipeline projects have been announced recently.

Major Canadian natural gas pipelines are shown in **Figure 9.3. Table 9.9** shows select North American natural gas pipeline developments that have been identified as having the potential to affect the Alberta market.

9.1.2 Railroads

North America's railroad network is extensive, linking almost all major cities and ports across the continent. The extent to which this rail network is interconnected allows not only movement across borders, but also across markets. Where pipelines offer shippers the ability to only access certain markets, rail allows producers to place their product on cars and ship it almost anywhere on the continent serviced by rail. Demand for unit trains, which generally consist of 100 dedicated tanker cars, has rapidly grown in recent years as oil producers have sought out additional transportation options.

Alberta's existing railroad system crosses major oil and NGL producing regions in the province. Transloading facilities in the province have come to include pipeline-connected storage hubs and rail terminals; concentrations of crude oil and NGL rail infrastructure are shown in **Figure 9.4**. Throughput capacity for oil and NGLs are

Table 9.6 Selected North American NGL pipeline system developments

Company Project	Start-up	Capacity (10^3 m^3/d)	Origin	Destination
Enbridge				
Norlite	2017	44.5	Fort Saskatchewan, AB	Fort McMurray, AB
Plains Midstream				
Rainbow II	TBD[a]	n/a[b]	Edmonton, AB	Nipisi Terminal, AB

[a] To be determined.

[b] Not available.

Table 9.7 Alberta's intraprovincial natural gas pipelines

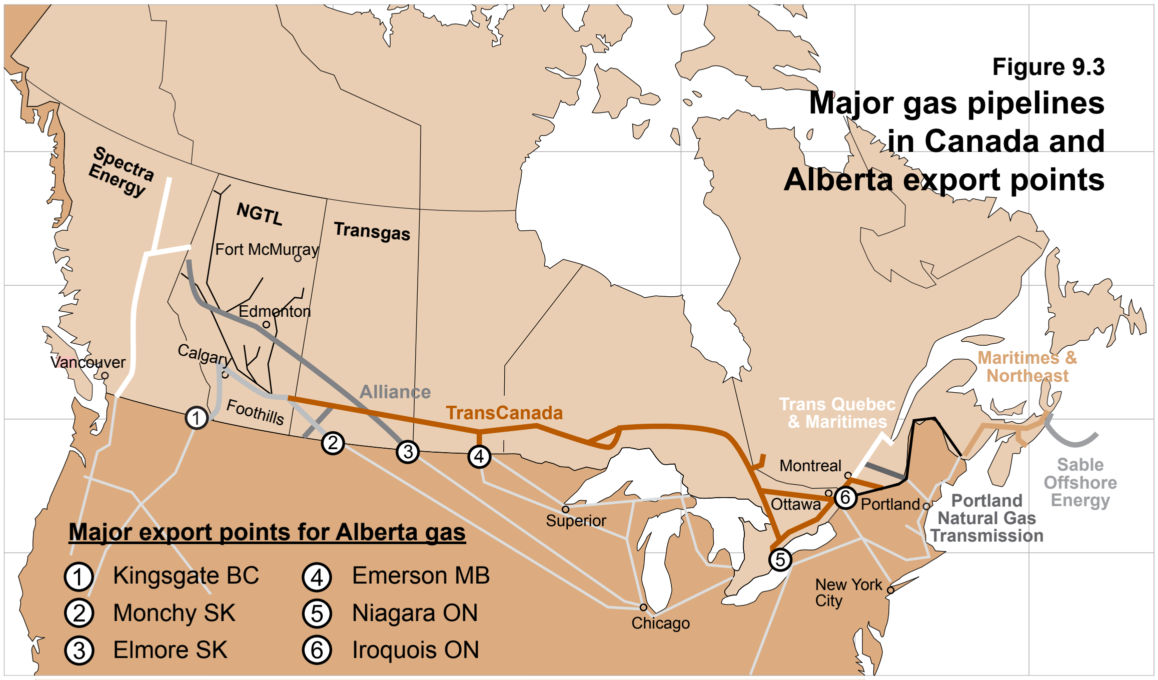
Name	Destination	Capacity (10^6 m^3/d)
ATCO		
ATCO system	A gathering system in central Alberta.	107.1
Suncor		
Suncor pipeline	Ft. McMurray	2.8
TransCanada		
NOVA Gas Transmission Ltd. (AB-BC border)	A network of natural gas pipelines with multiple receipt and delivery points within Alberta and at provincial borders.	63.9
NOVA Gas Transmission Ltd. (AB-Montana border)	A network of natural gas pipelines with multiple receipt and delivery points within Alberta and at provincial borders.	3.1
Foothills (Alberta system)	BC border	63.9
Enbridge		
Alliance[a]	Steelman, SK	130.5

[a] Current contracted capacity.

Table 9.8 Alberta's removal and import natural gas pipelines

Name	Destination	Capacity (10^6 m^3/d)
Enbridge		
Alliance[a]	Guardian, Illinois	47.9
TransCanada		
Mainline	Quebec-Vermont border	197.2
Foothills (BC)	Foothills (BC border)	84.5
Foothills (SK)	Foothills (SK border)	65.7

[a] Total contract capacity.



shown in **Table 9.10** and **Table 9.11**, respectively. The railroads connecting Alberta to ports in British Columbia have been previously strengthened to transport large unit trains of coal and other commodities.

In an effort to improve safety regulations associated with rail transportation in North America, Canada and the United States have brought forward legislation to retrofit and retire certain older rail cars used to transport petroleum products. Additional proposals have also been made in both countries which would see speed limits reduced on trains carrying flammable liquids in urban areas and require enhanced track maintenance schedules.

North American railroad systems connect all areas of the continent, which consequently allow access to international markets. Canada's major railway networks are owned primarily by Canadian Pacific Railway (CPR) and Canadian National Railway (CN), whose routes are depicted in **Figure 9.5**.

Major existing and proposed rail infrastructure related to oil and gas development in Alberta is as follows:

- Gibson Energy commenced operations at its Hardisty rail terminal in June 2014, which can handle up to 120 train cars of oil.
- In 2013, Canexus Corporation finished expanding its rail terminal capacity at its Bruderheim facility.
- Kinder Morgan and Imperial Oil plan to open the Edmonton Rail Terminal (ERT) in 2015 and expand the terminal's initial capacity of 629.3 10^3 m^3/d to an ultimate potential of 1573.2 10^3 m^3/d.
- Keyera and Kinder Morgan's Edmonton facility started shipments in 2014. The 251.7 10^3 m^3/d facility can accommodate 20 train cars.

Table 9.9 Selected North American natural gas pipeline system developments

Company Project	Start-up	Capacity (10^6 m^3/d)	Origin	Destination
Spectra Energy				
Iroquois Gas Transmission System				
South to North (SoNo)	2016	81.7	Canajoharie, NY	Waddington, NY
NEXUS Gas Transmission System	2017	28.2	Northeastern Ohio	Eastern Canada
TransCanada				
Eastern Mainline project	TBD[a]	n/a[b]	Markham, ON	Iroquois, ON

[a] To be determined.

[b] Not available.

Table 9.10 Major oil facilities in Alberta with rail terminals[a]

Operator	Location	Throughput capacity (10^3 m^3/d)
Gibson Energy Inc.	Hardisty	881.0
Canexus Corp.	Bruderheim	792.9
Kinder Morgan Energy Partners L.P. and Imperial Oil Limited	Edmonton	629.3
Keyera Corp. and Kinder Morgan Energy Partners	Edmonton	251.7
Pembina Pipeline Corp.	Edmonton	251.7
Keyera Corp. and Enbridge Inc.	South Cheecham	201.4
Plains Midstream Canada ULC	Mitsue	188.8

[a] Exceeding 188.8 10^3 m^3/d of throughput capacity.

Table 9.11 Major NGL facilities in Alberta with rail terminals[a]

Operator	Location	Throughput capacity (10^3 m^3/d)
Pembina Pipeline Corp.	Redwater	472.0
Spectra Energy Corp.	Empress	396.5
Plains Midstream Canada ULC	Fort Saskatchewan	377.6
Keyera Corp.	Edmonton	314.6
Keyera Corp.	Fort Saskatchewan	251.7
AltaGas	Harmattan	220.3
Keyera Corp.	Edmonton	214.0

[a] Exceeding 188.8 10^3 m^3/d of throughput capacity.

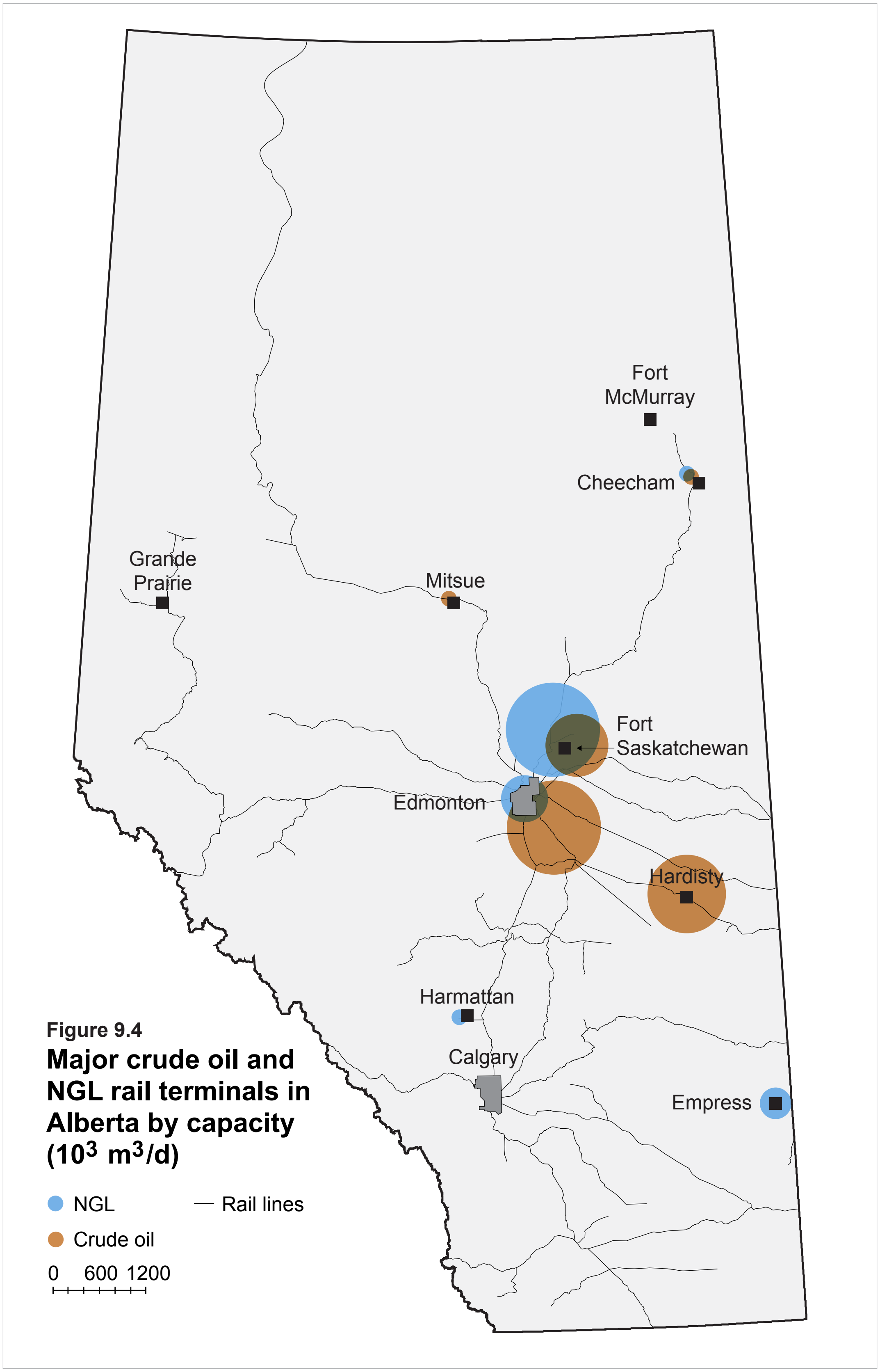
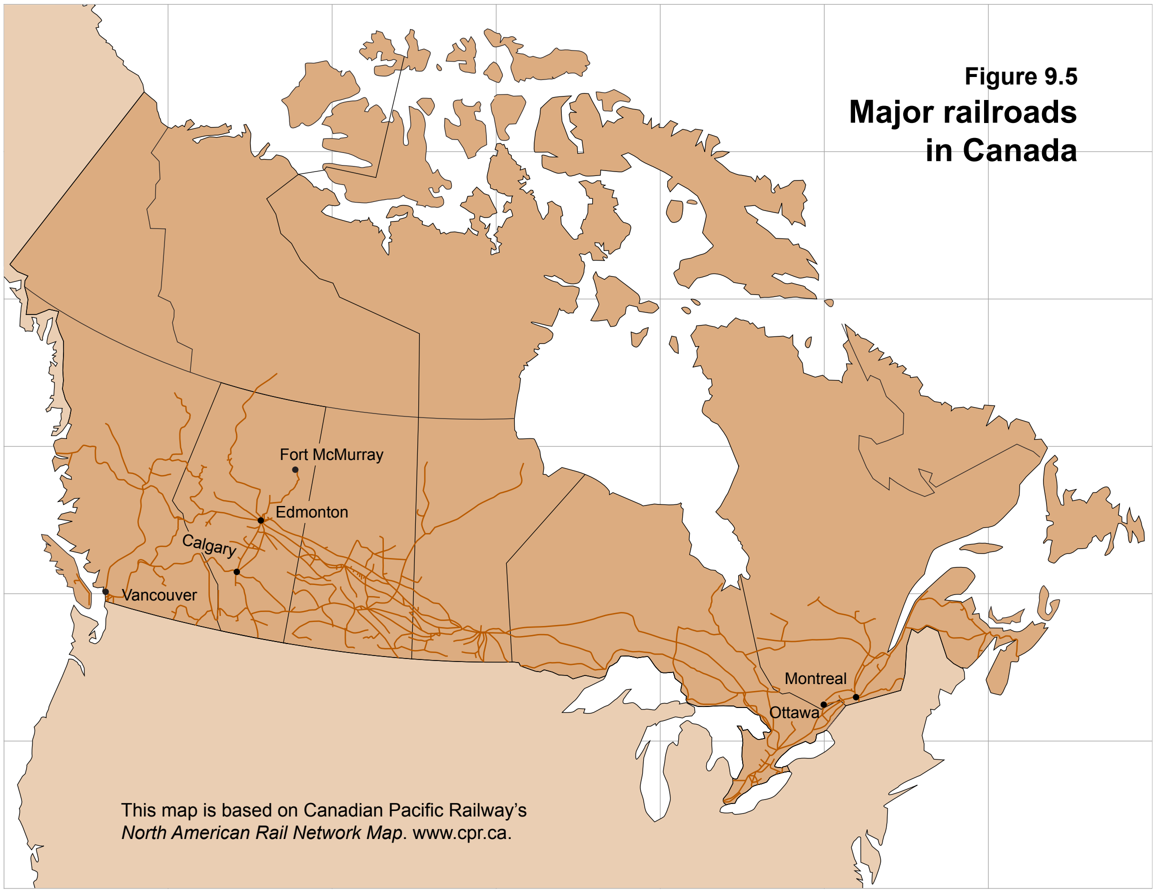


Figure 9.4
Major crude oil and NGL rail terminals in Alberta by capacity (10^3 m^3/d)



- In September 2013, Keyera completed construction of the South Cheecham Rail and Truck Terminal (SCRTT). The facility is capable of transloading NGLs and crude delivered by rail. The company has stated it has plans to expand throughput to 503.4 10^3 m^3/d from the existing 188.8 10^3 m^3/d capacity.

- Keyera also plans on constructing a rail terminal at Josephburg near Fort Saskatchewan to optimize propane movement out of western Canada. The project's start-up date is set for late 2015.

- Pembina has announced plans to develop the Canadian Diluent Hub. It is aiming to achieve full connectivity by 2017. The complex would handle diluent at its Heartland terminal near Fort Saskatchewan, including approximately 125.9 10^3 m^3/d of rail import capacity.

9.1.3 Highways

Starting with only a few major roads in 1905, Alberta's road network has expanded to include thousands of kilometres of paved and unpaved roads. Alberta has more than 31 000 km of highway that connect into highway systems in bordering Canadian provinces and territories as well as the United States. Highways help in the growth of the economy by facilitating the distribution of different commodities and goods all over the country and serve as important links to airways, waterways, and railways. Alberta's highways serve population centres, provincial and international border crossings, airports, transportation facilities, and major commercial hubs.

9.2 Plants and Facilities

The downstream sector of the oil and gas industry involves the refining of crude oil, crude bitumen, and raw natural gas produced by the upstream sector as well as the marketing of such refined products. Alberta produces an array of different marketable energy commodities such as propane, butane, diesel, naphtha, and gasoline.

9.2.1 Processing Plants – Oil Refineries

Oil refineries use crude oil, butanes, and natural gas as feedstock, along with upgraded and nonupgraded bitumen and pentanes plus, to produce a wide variety of refined petroleum products (RPPs). **Table 9.12** lists the capacities of Alberta’s four refineries in 2014.

9.2.2 Processing Plants – Natural Gas

Ethane and other NGLs are recovered mainly from the processing of natural gas. Gas reprocessing plants, often referred to as straddle plants, recover NGL components or NGL mix from marketable gas. They are usually located on rate-regulated main gas transmission pipelines at border delivery points.

Straddle plants remove much of the propane plus (C_3+) and ethane volumes, with the degree of recovery being determined by the plant’s extraction capability, contractual arrangements, and product demand. Field plants may send recovered NGL mix to centralized, large-scale fractionation plants where the mix is fractionated into specification products such as propane, butanes, and pentanes plus. A de-ethanizer tower, along with a turbo expander, chills the natural gas to isolate ethane from other NGLs.

Alberta’s straddle plants and fractionation plants are listed in **Table 9.13** and **Table 9.14**.

In Alberta, DOW Chemical Company’s (DOW) Fort Saskatchewan fractionator and Pembina’s Redwater fractionator separate ethane from the NGL stream. Ethane recovered at field processing plants, NGL fractionators, and straddle plants is shipped on the AEGS to the Alberta ethane market, mainly the petrochemical sector.

In Alberta, there are nearly 500 active gas processing plants that recover NGL mix or specification products, 10 fractionation plants that fractionate NGL mix streams into specification products, and 9 straddle plants.

Alberta’s petrochemical industry is the major consumer of ethane, which is used in the production of ethylene and polyethylene. Ethylene is one of the building blocks used to produce products such as packaging material, ethylene glycol, and styrene. The petrochemical industry also produces many other products such as fertilizer.

Petrochemical plants in Alberta are mainly located in Joffre and Fort Saskatchewan and represent one of the largest manufacturing industries. Alberta has four ethane-cracking plants, of which two are the world’s largest, with a combined capacity of 3.9 million tonnes of ethylene per year.

Announced processing facility projects are expected to increase liquids recovery to an estimated total of 36.4 10^3 m^3/d by 2017. This anticipated change is due to the addition of a de-ethanizer, NGL mix processing facilities expansions, the debottlenecking of current capacities, and pipeline connections. Pembina is expected

Table 9.12 Alberta refinery capacity in 2014 (10^3 m^3/d)

Refinery	Capacity
Imperial Edmonton	29.7
Petro-Canada Edmonton	22.6
Shell Scotford (in Fort Saskatchewan)	15.9
Husky Lloydminster	4.5

Table 9.13 Fractionation plants in Alberta

Area	Operator
Plains Buck Creek	Plains Midstream Canada ULC
Fort Saskatchewan	Keyera Energy Ltd.
Hardisty (Killam)	Gibson Energy ULC
Fort Saskatchewan	Plains Midstream Canada ULC
Kemp[a]	Stittco Energy Limited
Fort Saskatchewan	Dow Chemical Canada ULC
Redwater	Pembina NGL Corporation
High Prairie	Plains Midstream Canada ULC
Harmattan-Elkto N	Taylor Processing Inc.
Carrot Creek	Tervita Corporation

[a] Last volumetric activity was April 2013.

Table 9.14 Straddle plants in Alberta

Area	Operator
Empress	Spectra Energy Empress Management
Empress	Plains Midstream Canada ULC
Cochrane	Inter Pipeline Extraction Ltd.
Ellerslie (Edmonton)	AltaGas Ltd.
Empress	ATCO Energy Solutions Ltd.
Fort Saskatchewan[a]	ATCO Energy Solutions Ltd.
Empress	1195714 Alberta Ltd.
Joffre	AltaGas Ltd.
Atim (Villeneuve)	ATCO Energy Solutions Ltd.

[a] Last volumetric activity was August 2014.

to increase liquids production from wet gas at their Redwater fractionator by 21.8 10^3 m^3/d. Keyera is currently adding a 4.8 10^3 m^3/d de-ethanizer at their facility in Fort Saskatchewan, which should increase its total fractionation capacity by 11.4 10^3 m^3/d. Plains Midstream is expanding its Fort Saskatchewan facility, increasing its inlet capacity of C_3+ by 3.2 10^3 m^3/d.

9.2.3 Processing Plants – Upgraders

Alberta's five upgraders produce a variety of upgraded products: synthetic light sweet and medium sour crudes, including diesel (Suncor); light sweet synthetic crude (Syncrude, CNRL, and Nexen); and sweet and heavy synthetic oil and intermediate refinery feedstock (Shell). **Table 9.15** shows the average upgraded bitumen production in 2014.

9.2.4 Electricity Infrastructure

As of December 31, 2014, Alberta's total installed generation capacity, as set out on the Alberta Electric System Operator's (AESO) website was 16 151 megawatts (MW), of which 7143 MW was gas-fired, 6271MW was coal-fired, 1434 MW was wind-powered, 894 MW was hydro-powered, and 409 MW was from other sources (e.g., biomass, biogas, and solar).

According to the AESO, the dedicated natural gas-fired generation capacity increased significantly in 2014. As a result, the percentage of natural gas-fired capacity in the province classified as cogeneration decreased from 71 to 63 per cent. Cogeneration is the combined production of electricity and thermal energy using natural gas as the fuel source. Thermal energy is often used for manufacturing, heating, producing steam for in situ oil production, refining, and upgrading.

Alberta's electricity system has about 26 000 km of transmission lines. It's connected to systems in British Columbia, Saskatchewan, and Montana. These three interties allow Alberta to import or export electricity. In addition to the transmission interties, a natural gas-fired electricity generation unit in Fort Nelson (northern British Columbia) supplies power to the surrounding communities and sells surplus electricity into the Alberta grid.

Table 9.15 Average upgraded bitumen production in 2014 (10^3 m^3/d)[a]

Company/project name	Production
Syncrude	41.5
Suncor	47.1
Shell Canada Scotford	39.2
CNRL Horizon	17.7
Nexen Long Lake	6.1
Total	**151.6**

[a] Any discrepancies are due to rounding.

Appendix A Terminology and Conversion Factors

Terminology

Alberta Energy Company's storage hub (AECO-C)	The AECO-C hub is a trading point that sets the main pricing index for Albertan and Canadian natural gas.
Alberta Natural Gas Reference Price (ARP)	A monthly weighted average field price of all Alberta gas sales that is used for royalty purposes. The price is determined by the Alberta Department of Energy through a survey of actual sales transactions. Also known as the price of Alberta natural gas at the plant gate.
API gravity	A specific gravity scale developed by the American Petroleum Institute (API) for measuring the relative density or viscosity of various petroleum liquids.
Brent Blend (Brent)	A grade of light sweet crude oil derived from a mix of 15 different oil fields in the North Sea. Brent blend futures are traded on the Intercontinental Exchange Inc. (ICE) and are considered a global benchmark for oil prices.
Burner-tip	The location where a fuel is used by a consumer.
Butanes	In addition to its normal scientific meaning, a mixture mainly of butanes that ordinarily may contain some propane or pentanes plus (*Oil and Gas Conservation Act*, section 1(1)(j)).
Capital costs	Expenditures by a company to build, purchase, or upgrade physical assets such as land, equipment, and processing facilities.
Coal	A combustible sedimentary rock that contains at least 50 per cent by weight organic matter formed from plant or algal matter. (*Coal Conservation Act*, section 1(1)(d)).
Coalbed methane (CBM)	Naturally occurring dry gas, predominantly methane, produced during the transformation of organic matter into coal.
Coal seam	A layered unit of coal and inorganic matter that contains less than 1/3 inorganic matter by volume and does not contain a layer of inorganic matter exceeding 0.3 metres in thickness (*Coal Conservation Act*, section 1(1)(e.1)).
Cogeneration gas plant	A gas-fired plant used to generate both electricity and steam.
Commingled	Commingled flow describes the production of fluid from two or more separate zones through a single conduit.
Compressibility factor	A correction factor for non-ideal gas determined for gas from a pool at its initial reservoir pressure and temperature and, where necessary, includes factors to correct for acid gases.
Condensate	A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, that (i) is recovered or is recoverable at a well from an underground reservoir and may be gaseous in its virgin reservoir state but is liquid at the conditions under which its volume is measured or estimated, or (ii) is recovered from an in situ coal scheme and is liquid at the conditions under which its volume is measured or estimate (*Oil and Gas Conservation Act*, section 1(1)(k)).

Crude bitumen A naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulphur compounds and that, in its naturally occurring viscous state, will not flow to a well (*Oil Sands Conservation Act*, section 1(1)(c)).

Crude oil (conventional) A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, that is recovered or is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated, and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas, condensate or crude bitumen (*Oil and Gas Conservation Act*, section 1(1)(o)).

Crude oil (heavy) Crude oil with a density of 900 kg/m^3 or greater.

Crude oil (light–medium) Crude oil with a density less than 900 kg/m^3.

Crude oil (synthetic) A mixture, mainly of pentanes and heavier hydrocarbons, that may contain sulphur compounds, and is derived from crude bitumen and that is liquid at the conditions under which its volume is measured or estimated, and includes all other hydrocarbon mixtures so derived (*Oil and Gas Conservation Act*, section 1(1)(zz)).

Crude oil netback An economic indicator of profitability expressed as a dollar value per unit of production. Crude oil netbacks are calculated from the price of West Texas Intermediate (WTI) crude oil at Chicago less transportation and other charges to supply crude oil from the wellhead to the Chicago market. Alberta netback prices are adjusted for the U.S./Canadian dollar exchange rate, as well as crude quality differences.

Datum depth The approximate average depth relative to sea level of the midpoint of an oil or gas productive zone for the wells in a pool.

Decline rate The annual rate of decline in well productivity.

Deep-cut facility *See* NGL recovery (deep-cut gas facility).

Density The mass or amount of matter per unit volume.

Density, relative (raw gas) The density relative to air of raw gas upon discovery, determined by an analysis of a gas sample representative of a pool under atmospheric conditions.

Development entity (DE) An administrative unit consisting of multiple formations in a designated area described in an order of the AER. Within the DE gas may be produced without segregation in the wellbore, subject to certain criteria specified in section 3.051 of the *Oil and Gas Conservation Rules*.

Diluent Lighter viscosity petroleum products that are used to dilute crude bitumen for transport in pipelines.

Discovery year The year when drilling was completed for the well in which the oil or gas pool was discovered.

Drain wells More than one event sequence (leg) in a multileg well is open to the same pool and is capable of production. The event sequence considered to be the main contributor of production carries the producing status. The other contributing events carry a drain status.

Economic strip ratio Ratio of waste (overburden material that covers mineable ore) to ore (coal or oil sands) used to define an economic limit below which it is economical to remove the overburden to recover the ore.

Enhanced recovery The increased recovery from a pool achieved by artificial means or by the application of energy extrinsic to the pool, which artificial means or application includes pressuring, cycling, pressure maintenance or injection to the pool of a substance or form of energy, but does not include the injection in a well of a substance or form of energy for the sole purpose of
(i) aiding in the lifting of fluids in the well, or
(ii) stimulation of the reservoir at or near the well by mechanical, chemical, thermal or explosive means (*Oil and Gas Conservation Act*, section 1(1)(r)).

Established reserves Those reserves recoverable under current technology and present and anticipated economic conditions specifically proved by drilling, testing, or production, plus the portion of contiguous recoverable reserves that are interpreted to exist from geological, geophysical, or similar information with reasonable certainty.

Ethane In addition to its normal scientific meaning, a mixture mainly of ethane that ordinarily may contain some methane or propane (*Oil and Gas Conservation Act*, section 1(1)(s)).

Extraction The process of liberating hydrocarbons (e.g., propane, bitumen) from their source (e.g., raw gas, mined oil sands).

Feedstock A raw material supplied to a refinery, oil sands upgrader, or petrochemical plant.

Field (i) The general surface area or areas underlain or appearing to be underlain by one or more pools, or
(ii) the subsurface regions vertically beneath a surface area or areas referred to in subclause (i) (*Oil and Gas Conservation Act*, section 1(1)(x)).

Field (gas) plant A natural gas facility that processes raw gas and produces a marketable product that meets pipeline specifications. These plants, located near the gas source, remove impurities, such as water and hydrogen sulphide, from the raw gas stream and may also extract natural gas liquids. *See also* NGL recovery (extraction plant).

Field plant gate The point at which the gas exits the field plant and enters a pipeline.

Fractionation plant *See* NGL recovery (fractionation plant).

Free On Board (FOB) price FOB represents an international pricing point where, after a commodity is loaded on a ship, the liability for and the cost of shipping the commodity transfers from a seller to a buyer.

Gas Raw gas, synthetic coal gas or marketable gas or any constituent of raw gas, synthetic coal gas, condensate, crude bitumen or crude oil that is recovered in processing and that is gaseous at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, section 1(1)(y)).

Gas (associated) Gas in a free state in communication in a reservoir with crude oil under initial reservoir conditions.

Gas (dry) Raw or processed gas that contains little to no natural gas liquids.

Gas (liquids-rich) Raw gas that contains a relatively high concentration of natural gas liquids.

Gas (marketable) A mixture mainly of methane originating from raw gas, if necessary through the processing of the raw gas for the removal or partial removal of some constituents, and that meets specifications for use as a domestic, commercial or industrial fuel or as an industrial raw material (*Oil and Gas Conservation Act*, section 1(1)(ee)). Marketable gas is measured at standard conditions of 101.325 kPa and 15°C.

Gas (nonassociated) Gas that is not in communication in a reservoir with an accumulation of liquid hydrocarbons at initial reservoir conditions.

Gas (raw) A mixture containing methane, other paraffinic hydrocarbons, nitrogen, carbon dioxide, hydrogen sulphide, helium and minor impurities, or some of them, that is recovered or is recoverable at a well from an underground reservoir and is gaseous at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, section 1(1)(tt)).

Gas (solution) Gas that is dissolved in crude oil under reservoir conditions and evolves as a result of pressure and temperature changes.

Gas (wet) Raw or processed gas that contains natural gas liquids.

Gas-oil ratio (initial solution) The volume of gas (in cubic metres, measured under standard conditions) contained in one stock-tank cubic metre of oil under initial reservoir conditions.

Good production practice (GPP) Production of crude oil or raw gas at a rate
(i) not governed by a base allowable, but
(ii) limited to what can be produced without adversely and significantly affecting conservation, the prevention of waste, or the opportunity of each owner in the pool to obtain his share of production (*Oil and Gas Conservation Rules*, section 1.020(2)9). This practice is authorized by the AER either to improve the economics of production from a pool and thus defer its abandonment or to avoid unnecessary administrative expense associated with regulation or production restrictions where this serves little or no purpose.

Gross heating value (of dry gas) The heat liberated by burning moisture-free gas at standard conditions and condensing the water vapour to a liquid state.

Henry Hub A distribution hub on a main natural gas pipeline system in the United States near Erath, Louisiana. It is the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX).

Horizontal well A well in which the lower part of the wellbore is drilled parallel to the zone of interest.

Initial established reserves Established reserves prior to the deduction of any production.

Initial volume in-place The volume or mass of crude oil, crude bitumen, raw natural gas, or coal calculated or interpreted to exist in the ground before any quantity has been produced.

Maximum day rate The operating day rate for gas wells when they are first placed on production. The estimation of the maximum day rate requires the average hourly production rate. For each well, the annual production is divided by the hours that the well produced in that year to obtain the average hourly production for the year. This hourly rate is then multiplied by 24 hours to yield an estimate of a full-day operation of a well, which is referred to as the maximum day rate.

Maximum recoverable thickness The assumed maximum operational reach of underground coal mining equipment in a single seam.

Mean formation depth The approximate average depth below kelly bushing of the midpoint of an oil or gas productive zone for the wells in a pool.

Methane In addition to its normal scientific meaning, a mixture mainly of methane that ordinarily may contain some ethane, nitrogen, helium, or carbon dioxide (*Oil and Gas Conservation Act*, section 1(1)(ff)).

Multilateral well
A well where two or more production holes, usually horizontal in direction with reference to the zone of interest, are drilled from a single surface location.

Natural gas
See Gas.

Natural gas liquids (NGLs)
Ethane, propane, butanes, pentanes plus, or a combination of these obtained from the processing of raw gas or condensate.

NGL recovery (deep-cut gas facility)
A natural gas processing facility capable of extracting ethane and other natural gas liquids.

NGL recovery (extraction plant)
A natural gas processing facility that can remove natural gas liquids from raw or processed natural gas. Extraction plants can remove an NGL mix, but cannot split the natural gas liquids into separate components. *See also* field (gas) plant.

NGL recovery (fractionation plant)
A natural gas processing facility that takes a natural gas liquids stream and separates out its different components: ethane, propane, butane, and pentanes plus.

NGL recovery (shallow-cut gas facility)
A natural gas processing facility that extracts propane, butane, and pentanes plus.

NGL recovery (straddle plant)
A reprocessing plant on major natural gas transmission lines near Alberta's borders that extracts natural gas liquids from marketable gas. Most plants are deep-cut facilities that then ship an NGL stream to fractionation plants in central Alberta.

Nonupgraded bitumen
Nonupgraded bitumen refers to crude bitumen that is blended with a lighter-viscosity product (referred to as a diluent) to meet specifications for transport through pipelines.

Off-gas
Natural gas produced from upgrading bitumen. This gas is typically rich in natural gas liquids and olefins.

Oil
Condensate, crude oil, or synthetic coal liquid or a constituent of raw gas, condensate, or crude oil that is recovered in processing, that is liquid at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, section 1(1)(hh)).

Oil sands
(i) sands and other rock materials containing crude bitumen,
(ii) the crude bitumen contained in those sands and other rock materials, and
(iii)any other mineral substances, other than natural gas, in association with that crude bitumen or those sands and other rock materials referred to in subclauses (i) and (ii) (*Oil Sands Conservation Act*, section 1(1)(l)).

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 (*Oil and Gas Conservation Act*, section 1(1)(jj)).

Operating costs
Includes both fixed and variable costs associated with running a project on a day-to-day basis.

Overburden
When used in reference to mining, overburden is the thickness of the material above a mineable occurrence of coal or bitumen; otherwise, it is the soil and loose material between the land's surface and solid bedrock.

Pay thickness (average)
The bulk rock volume of a reservoir of crude oil, bitumen, or gas divided by its area.

Pentanes plus	A mixture mainly of pentanes and heavier hydrocarbons that ordinarily may contain some butanes and that is obtained from the processing of raw gas, condensate or crude oil (*Oil and Gas Conservation Act*, section 1(1)(mm)).
Pool	(i) a natural underground reservoir containing or appearing to contain an accumulation of oil or gas, or both, separated or appearing to be separated from any other such accumulation, or (ii) in respect of an in situ coal scheme, that portion of a coal deposit that has been or is intended to be converted to synthetic coal gas or synthetic coal liquid (*Oil and Gas Conservation Act*, section 1(1)(oo)).
Porosity	The effective pore space of the rock volume determined from core analysis and well log data measured as a fraction of rock volume.
Pressure (initial)	The reservoir pressure at the reference elevation of a pool upon discovery.
Propane	In addition to its normal scientific meaning, a mixture mainly of propane that ordinarily may contain some ethane or butanes (*Oil and Gas Conservation Act*, section 1(1)(rr)).
Recovery (enhanced)	*See* Enhanced recovery.
Recovery (pool)	In gas pools, the fraction of the in-place resources of gas expected to be recovered under the subsisting recovery mechanism.
Recovery (primary)	Recovery of oil by natural depletion processes only, measured as a volume that is recovered or as a fraction of the in-place oil.
Refined petroleum products	End products in the refining process.
Refinery light ends	Light oil products produced at a refinery; includes gasoline and aviation fuel.
Remaining established reserves	Initial established reserves less cumulative production.
Reprocessing facilities	Gas processing plants used to extract ethane and natural gas liquids from marketable natural gas. Such facilities, also referred to as straddle plants, are located on major natural gas transmission lines.
Reservoir	A porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons (oil and/or gas) that is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.
Sales gas	A volume of gas transacted in a time period. This gas may be augmented with gas from storage.
Saturation (gas)	The fraction of pore space in the reservoir rock occupied by gas upon discovery.
Saturation (water)	The fraction of pore space in the reservoir rock occupied by water upon discovery.
Shale gas	The naturally occurring gas produced from organic-rich, fine-grained rocks.
Shale NGLs	The naturally occurring mixture of natural gas liquids produced from organic-rich, fine-grained rocks.
Shale oil	A naturally occurring mixture of mainly pentanes and heavier hydrocarbons produced from organic-rich, fine-grained rocks.

Shrinkage factor (initial) The volume occupied by one cubic metre of oil from a pool measured at standard conditions after flash gas liberation consistent with the surface separation process and divided by the volume occupied by the same oil and gas at the pressure and temperature of a pool upon discovery.

Solvent A suitable mixture of hydrocarbons ranging from methane to pentanes plus but consisting largely of methane, ethane, propane, and butanes for use in enhanced-recovery operations.

Specification product A crude oil or refined petroleum product with defined properties.

Sterilization The rendering of otherwise definable economic ore as unrecoverable.

Straddle plant *See* NGL recovery (straddle plant).

Strike area An administrative geographical boundary used in relation to potential resource accumulations.

Strip ratio The amount of overburden that must be removed to gain access to a unit amount of coal. A stripping ratio may be expressed as (1) the thickness of overburden to the thickness of coal, (2) the volume of overburden to the volume coal, (3) the weight of overburden to the weight of coal, or (4) the cubic yards of overburden to tons of coal. Stripping ratios are commonly used to express the maximum thickness, volume, or weight of overburden that can be profitably removed to obtain a unit amount of coal.

Successful wells drilled Wells drilled for gas or oil that are cased and not abandoned at the time of drilling.

Surface loss A sum of the fractions of recoverable gas that is removed as acid gas and liquid hydrocarbons, and gas that is used as lease or plant fuel or that is flared.

Synthetic crude oil (SCO) *See* crude oil (synthetic).

Temperature The initial reservoir temperature upon discovery at the reference elevation of a pool.

Ultimate potential An estimate of the initial established reserves that will have been developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of that area and anticipated technology and economic conditions. Ultimate potential includes cumulative production, remaining established reserves, and future additions through extensions and revisions to existing pools and the discovery of new pools. For hydrocarbons, ultimate potential volumes can be determined by the following simple equation: ultimate potential = initial established reserves + additions to existing pools + future discoveries.

Upgraded bitumen A mixture of hydrocarbons, similar to crude oil, derived by upgrading bitumen from oil sands. Generally considered to be equivalent to synthetic crude oil (SCO) but can also include refined petroleum products.

Upgrading A process that converts bitumen and heavy crude oil into a mixture of lighter hydrocarbons by removing carbon or adding hydrogen.

Wells placed on production Wells that have been physically connected to gathering infrastructure and are reporting production; includes newly drilled wells that have been placed on production and recompletions into new zones of existing wells.

Western Canadian Select (WCS)	A grade of heavy crude oil derived from of a mix of heavy crude oil and crude bitumen blended with diluents. The price of WCS is often used as a representative price for Canadian heavy crude oils.
West Texas Intermediate (WTI)	A light sweet crude oil that is typically referenced for pricing at Cushing, Oklahoma.
Zone	Any stratum or sequence of strata that is designated by the AER as a zone (*Oil and Gas Conservation Act*, section 1(1)(ggg)).

PSAC Areas

The Petroleum Services Association of Canada (PSAC) has sectioned Canada into a number of geographic regions based on the predominate type of geological interest to the oil and gas industry. **Figure AA.1** shows the PSAC areas in Alberta. The AER often refers to the historical, current, and future oil and gas activity it discusses by PSAC area.

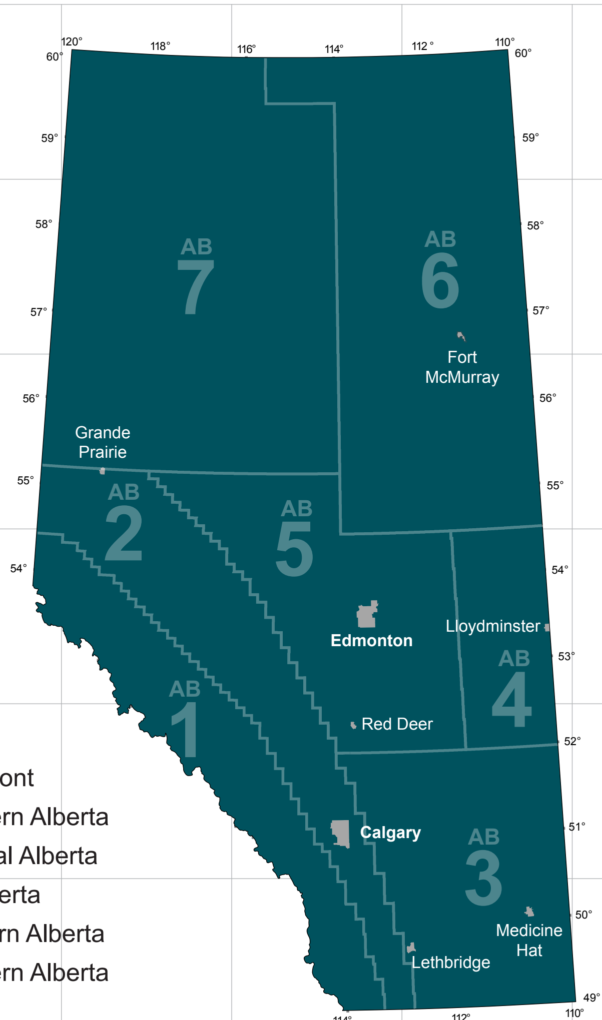


Figure AA.1
PSAC areas in Alberta

AB1 Foothills
AB2 Foothills Front
AB3 Southeastern Alberta
AB4 East Central Alberta
AB5 Central Alberta
AB6 Northeastern Alberta
AB7 Northwestern Alberta

Symbols

International System of Units (SI)

°C degree	Celsius	M	mega
d	day	m	metre
EJ	exajoule	MJ	megajoule
ha	hectare	mol	mole
J	joule	T	tera
kg	kilogram	t	tonne
kPa	kilopascal	TJ	terajoule

Imperial

bbl	barrel	°F degree	Fahrenheit
Btu	British thermal unit	psia	pounds per square inch absolute
cf	cubic foot	psig	pounds per square inch gauge
d	day	M	thousand
MM	million	B	billion
T	trillion		

Conversion Factors

Metric and Imperial Equivalent Units[a]

Metric	Imperial
1 m^3 of gas[b] (101.325 kPa and 15°C)	= 35.49373 cubic feet of gas
1 m^3 of ethane (equilibrium pressure and 15°C)	= 6.3301 Canadian barrels of ethane (equilibrium pressure and 60°F)
1 m^3 of propane (equilibrium pressure and 15°C)	= 6.3000 Canadian barrels of propane (equilibrium pressure and 60°F)
1 m^3 of butanes (equilibrium pressure and 15°C)	= 6.2968 Canadian barrels of butanes (equilibrium pressure and 60°F)
1 m^3 of oil or pentanes plus (equilibrium pressure and 15°C)	= 6.2929 Canadian barrels of oil or pentanes plus (equilibrium pressure and 60°F)
1 m^3 of water (equilibrium pressure and 15°C)	= 6.2901 Canadian barrels of water (equilibrium pressure and 60°F)
1 tonne	= 0.9842064 (U.K.) long tons (2240 pounds)
1 tonne	= 1.102311 short tons (2000 pounds)
1 kilojoule	= 0.9482133 British thermal units (Btu) as defined in the federal *Gas Inspection Act* (60-61°F)

[a] Reserves data in this report are presented in the International System of Units (SI). The provincial totals and a few other major totals are shown in both SI units and the imperial equivalents in the various tables.

[b] Volumes of gas are given as at a standard pressure and temperature of 101.325 kPa and 15°C respectively.

Value and Scientific Notation

Term	Value (short scale)	Scientific notation
kilo	thousand	10^{3}
mega	million	10^{6}
giga	billion	10^{9}
tera	thousand billion (trillion)	10^{12}
peta	million billion	10^{15}
exa	billion billion	10^{18}

Energy Content Factors

Energy resource	Gigajoules
Natural gas (per thousand cubic metres)	37.4[a]
Ethane (per cubic metre)	18.5
Propane (per cubic metre)	25.4
Butanes (per cubic metre)	28.2
Oil (per cubic metre)	
Light and medium crude oil	38.5
Heavy crude oil	41.4
Bitumen	42.8
Upgraded bitumen (synthetic crude oil)	39.4
Pentanes plus	33.1
Refined petroleum products (per cubic metre)	
Motor gasoline	34.7
Diesel	38.7
Aviation turbo fuel	35.9
Aviation gasoline	33.5
Kerosene	37.7
Light fuel oil	38.7
Heavy fuel oil	41.7
Naphthas	35.2
Lubricating oils and greases	39.2
Petrochemical feedstock	35.2
Asphalt	44.5
Coke	28.8
Other products (from refinery)	39.8
Coal (per tonne)	
Subbituminous	18.5
Bituminous	25.0
Electricity (per megawatt-hour of output)	3.6

[a] Based on the heating value at 1000 Btu/cf.

Appendix B Summary of Crude Bitumen, Conventional Crude Oil, Natural Gas Reserves, and Natural Gas Liquids

Table B.1 Initial in-place resources of crude bitumen by deposit

Oil Sands Area Oil sands deposit	Depth/region/zone (m)	Resource determination method	Initial volume in-place (10^6 m^3)
Athabasca			
Upper Grand Rapids	150–450+	Isopach	5 817
Middle Grand Rapids	150–450+	Isopach	2 171
Lower Grand Rapids	150–450+	Isopach	1 286
Wabiskaw-McMurray	0–750+	Isopach	152 432
Nisku	200–800+	Isopach	16 232
Grosmont	All zones	Isopach	64 537
Subtotal			**242 475**
Cold Lake			
Upper Grand Rapids	All zones	Isopach	5 377
Lower Grand Rapids	All zones	Isopach	10 004
Clearwater	350–625	Isopach	9 422
Wabiskaw-McMurray	Northern	Isopach	2 161
Wabiskaw-McMurray	Central-southern	Building block	1 439
Wabiskaw-McMurray	Cummings & McMurray	Isopach	687
Subtotal			**29 090**
Peace River			
Bluesky-Gething	300–800+	Isopach	10 968
Belloy	675–700	Building block	282
Upper Debolt	500–800	Building block	1 830
Lower Debolt	500–800	Building block	5 970
Shunda	500–800	Building block	2 510
Subtotal			**21 560**
Total			**293 125**

Table B.2 Basic data of crude bitumen deposits

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in-place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation mass (fraction)	Bitumen saturation pore volume (fraction)	Porosity (fraction)	Water saturation (fraction)
Athabasca								
Upper Grand Rapids								
150–450+	Isopach	5 817.00	359.00	8.5	0.092	0.58	0.33	0.42
Middle Grand Rapids								
150–450+	Isopach	2 171.00	183.00	6.8	0.084	0.55	0.32	0.45
Lower Grand Rapids								
150–450+	Isopach	1 286.00	134.00	5.6	0.083	0.52	0.33	0.48
Wabiskaw-McMurray								
0–65 (mineable)	Isopach	20 823.00	375.00	25.9	0.101	0.76	0.28	0.24
65–750+ (in situ)	Isopach	131 609.00	4 694.00	13.1	0.102	0.73	0.29	0.27
Nisku								
200–800+	Isopach	16 232.00	819.00	14.4	0.057	0.68	0.20	0.32
Grosmont								
D	Isopach	32 860.00	850.00	21.0	0.081	0.81	0.23	0.19
C	Isopach	18 755.00	1 069.00	13.6	0.054	0.78	0.17	0.22
B	Isopach	4 450.00	787.00	4.9	0.048	0.76	0.15	0.24
A	Isopach	8 472.00	1 274.00	6.5	0.041	0.72	0.14	0.28
Cold Lake								
Upper Grand Rapids								
All Zones	Total Isopach	5 377.00	612.00	4.8	0.090	0.65	0.28	0.35
Colony 1								
Lindbergh C	Isopach	0.18	0.05	1.5	0.115	0.79	0.31	0.21
Beaverdam A	Isopach	7.33	1.05	2.9	0.115	0.79	0.31	0.21
Beaverdam B	Isopach	4.75	0.52	3.5	0.122	0.84	0.31	0.16
Beaverdam C	Isopach	2.03	0.26	3.1	0.119	0.76	0.33	0.24
Beaverdam/ Bonnyville A	Isopach	12.11	1.90	2.6	0.116	0.80	0.31	0.20
Colony 2								
Frog Lake A	Isopach	2.01	0.47	1.8	0.109	0.75	0.31	0.25
Frog Lake B	Isopach	0.11	0.04	1.3	0.093	0.67	0.30	0.33
Frog Lake C	Isopach	0.35	0.12	1.3	0.103	0.74	0.30	0.26
Frog Lake D	Isopach	0.29	0.10	1.3	0.099	0.71	0.30	0.29
Frog Lake E	Isopach	0.43	0.13	1.4	0.106	0.79	0.29	0.21
Frog Lake F	Isopach	0.33	0.10	1.7	0.092	0.69	0.29	0.31

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Table B.2 (*continued*)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in-place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation mass (fraction)	Bitumen saturation pore volume (fraction)	Porosity (fraction)	Water saturation (fraction)
Frog Lake M	Isopach	0.55	0.14	1.8	0.100	0.72	0.30	0.28
Frog Lake N	Isopach	0.80	0.25	1.5	0.099	0.71	0.30	0.29
Frog Lake O	Isopach	0.15	0.03	2.5	0.096	0.66	0.31	0.34
Lindbergh A	Isopach	0.83	0.26	1.6	0.091	0.68	0.29	0.32
Lindbergh D	Isopach	1.20	0.13	3.4	0.130	0.86	0.32	0.14
Lindbergh E	Isopach	6.11	0.39	5.3	0.139	0.92	0.32	0.08
Lindbergh F	Isopach	0.85	0.09	3.3	0.136	0.90	0.32	0.10
Lindbergh G	Isopach	2.35	0.33	2.7	0.124	0.82	0.32	0.18
Lindbergh J	Isopach	3.56	0.60	2.6	0.106	0.76	0.30	0.24
Lindbergh K	Isopach	6.23	0.92	3.0	0.107	0.74	0.31	0.26
Lindbergh L	Isopach	1.99	0.31	2.4	0.125	0.83	0.32	0.17
Colony 3								
Frog Lake G	Isopach	0.48	0.09	2.1	0.116	0.83	0.30	0.17
Frog Lake H	Isopach	0.15	0.06	1.2	0.096	0.69	0.30	0.31
Frog Lake I	Isopach	1.61	0.23	2.9	0.111	0.80	0.30	0.20
Frog Lake J	Isopach	1.03	0.20	2.2	0.112	0.74	0.32	0.26
Frog Lake L	Isopach	130.95	6.43	7.4	0.130	0.86	0.32	0.14
Frog Lake P	Isopach	0.70	0.15	2.3	0.092	0.69	0.29	0.31
Lindbergh H	Isopach	2.04	0.24	3.2	0.124	0.82	0.32	0.18
Lindbergh I	Isopach	0.15	0.02	2.9	0.121	0.80	0.32	0.20
Colony Channel								
St. Paul A	Isopach	6.41	0.68	3.2	0.140	0.89	0.33	0.11
Grand Rapids 2								
Beaverdam A	Isopach	3.86	0.70	2.3	0.112	0.74	0.32	0.26
Beaverdam B	Isopach	1.96	0.39	2.5	0.094	0.70	0.29	0.30
Beaverdam D	Isopach	1.12	0.25	2.0	0.103	0.71	0.31	0.29
Beaverdam E	Isopach	0.23	0.11	0.9	0.111	0.71	0.33	0.29
Beaverdam G	Isopach	1.41	0.30	1.9	0.115	0.76	0.32	0.24
Beaverdam H	Isopach	9.97	1.34	3.0	0.118	0.78	0.32	0.22
Beaverdam I	Isopach	0.40	0.11	1.4	0.130	0.77	0.35	0.23
Frog Lake/ Beaverdam A	Isopach	64.45	6.69	3.7	0.125	0.77	0.34	0.23
Beaverdam/ Bonnyville A	Isopach	2.59	0.53	2.1	0.112	0.74	0.32	0.26

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Table B.2 (*continued*)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in-place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation mass (fraction)	Bitumen saturation pore volume (fraction)	Porosity (fraction)	Water saturation (fraction)
Grand Rapids Channel								
Wolf Lake A	Isopach	14.90	0.35	14.8	0.140	0.80	0.36	0.20
Waseca								
Frog Lake A	Isopach	1.09	0.38	1.7	0.076	0.57	0.29	0.43
Frog Lake B	Isopach	77.34	4.65	6.8	0.116	0.77	0.32	0.23
Beaverdam A	Isopach	4.59	0.21	8.6	0.121	0.77	0.33	0.23
Beaverdam B	Isopach	9.72	0.30	10.7	0.145	0.89	0.34	0.11
Beaverdam C	Isopach	6.57	0.15	15.0	0.140	0.86	0.34	0.14
Frog Lake/Lindbergh A	Isopach	135.86	15.56	4.3	0.095	0.68	0.30	0.32
Lower Grand Rapids								
All Zones	Total Isopach	1 004.00	658.00	7.8	0.092	0.65	0.30	0.35
Sparky								
Frog Lake A	Isopach	4.60	0.75	2.9	0.100	0.69	0.31	0.31
Frog Lake B	Isopach	0.30	0.06	2.2	0.109	0.72	0.32	0.28
Frog Lake C	Isopach	0.79	0.16	2.2	0.107	0.74	0.31	0.26
Frog Lake D	Isopach	0.21	0.07	1.7	0.083	0.62	0.29	0.38
Frog Lake E	Isopach	1.54	0.31	2.6	0.087	0.65	0.29	0.35
Frog Lake F	Isopach	12.36	1.47	3.1	0.130	0.83	0.33	0.17
Frog Lake G	Isopach	0.51	0.06	3.2	0.123	0.85	0.31	0.15
Frog Lake H	Isopach	0.09	0.02	1.7	0.127	0.81	0.33	0.19
Frog Lake I	Isopach	5.72	0.74	2.6	0.144	0.85	0.35	0.15
Lindbergh A	Isopach	54.96	8.17	3.1	0.102	0.70	0.31	0.30
Lindbergh C	Isopach	0.91	0.37	1.4	0.084	0.60	0.30	0.40
Lindbergh D	Isopach	26.51	4.05	2.7	0.116	0.74	0.33	0.26
Lindbergh E	Isopach	0.12	0.09	0.8	0.078	0.67	0.26	0.33
Lindbergh F	Isopach	0.31	0.14	1.3	0.081	0.58	0.30	0.42
Lindbergh I	Isopach	0.13	0.07	0.9	0.100	0.64	0.33	0.36
Lindbergh K	Isopach	0.84	0.24	1.7	0.093	0.67	0.30	0.33
Lindbergh L	Isopach	3.45	0.58	2.1	0.140	0.83	0.34	0.17
Lindbergh M	Isopach	7.10	0.85	3.1	0.130	0.83	0.33	0.17
Beaverdam A	Isopach	3.90	0.30	5.2	0.119	0.73	0.34	0.27
Beaverdam B	Isopach	3.40	0.33	4.8	0.103	0.63	0.34	0.37
Beaverdam C	Isopach	6.53	0.79	3.0	0.130	0.80	0.34	0.20

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Table B.2 (*continued*)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in-place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation mass (fraction)	Bitumen saturation pore volume (fraction)	Porosity (fraction)	Water saturation (fraction)
Beaverdam D	Isopach	30.23	3.48	3.3	0.124	0.82	0.32	0.18
Beaverdam E	Isopach	27.25	3.41	3.0	0.127	0.81	0.33	0.19
Beaverdam F	Isopach	8.07	1.17	2.6	0.129	0.82	0.33	0.18
Beaverdam H	Isopach	1.68	0.21	2.9	0.133	0.79	0.35	0.21
Cold Lake A	Isopach	9.74	1.00	3.7	0.128	0.76	0.35	0.24
Cold Lake B	Isopach	1.77	0.27	2.4	0.135	0.77	0.36	0.23
Mann Lake/ Seibert Lk A	Isopach	6.61	0.55	4.4	0.129	0.82	0.33	0.18
Lower Grand Rapids 2								
Frog Lake OO	Isopach	1.71	0.27	2.9	0.103	0.74	0.30	0.26
Frog Lake QQ	Isopach	0.55	0.10	2.2	0.119	0.82	0.31	0.18
Lindbergh G	Isopach	35.32	5.94	2.8	0.100	0.69	0.31	0.31
Lindbergh K	Isopach	0.76	0.21	2.0	0.084	0.63	0.29	0.37
Lindbergh VV	Isopach	0.36	0.12	1.5	0.095	0.68	0.30	0.32
Lindbergh WW	Isopach	2.60	0.51	2.0	0.122	0.78	0.33	0.22
Beaverdam A	Isopach	4.66	1.67	1.8	0.069	0.62	0.25	0.38
Cold Lake A	Isopach	3.09	0.89	1.5	0.111	0.71	0.33	0.29
Cold Lake D	Isopach	0.58	0.19	1.2	0.122	0.75	0.34	0.25
Lower Grand Rapids 3								
Frog Lake C	Isopach	4.80	0.46	4.4	0.112	0.77	0.31	0.23
Frog Lake D	Isopach	10.38	1.09	3.7	0.121	0.80	0.32	0.20
Frog Lake E	Isopach	4.50	0.88	2.3	0.106	0.73	0.31	0.27
Frog Lake F	Isopach	0.41	0.10	1.9	0.098	0.73	0.29	0.27
Lindbergh F	Isopach	31.58	3.02	4.2	0.118	0.78	0.32	0.22
Lindbergh L	Isopach	1.58	0.24	2.9	0.108	0.69	0.33	0.31
Lindbergh M	Isopach	8.40	1.46	2.7	0.100	0.69	0.31	0.31
Lindbergh O	Isopach	11.50	1.54	3.7	0.095	0.68	0.30	0.32
Lindbergh P	Isopach	2.04	0.25	3.5	0.110	0.76	0.31	0.24
Lindbergh Q	Isopach	27.61	2.92	3.7	0.119	0.79	0.32	0.21
Lindbergh S	Isopach	2.46	0.37	2.8	0.113	0.72	0.33	0.28
Lindbergh T	Isopach	2.97	0.47	2.6	0.115	0.76	0.32	0.24
Lindbergh U	Isopach	0.18	0.06	1.4	0.094	0.70	0.29	0.30
Lindbergh V	Isopach	0.13	0.06	1.3	0.081	0.56	0.31	0.44
Lindbergh X	Isopach	0.75	0.20	2.4	0.073	0.57	0.28	0.43

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Table B.2 (*continued*)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in-place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation mass (fraction)	Bitumen saturation pore volume (fraction)	Porosity (fraction)	Water saturation (fraction)
Lindbergh Y	Isopach	1.61	0.35	2.5	0.086	0.59	0.31	0.41
Lindbergh Z	Isopach	0.12	0.07	0.8	0.094	0.65	0.31	0.35
Lindbergh AA	Isopach	3.26	0.50	3.1	0.099	0.71	0.30	0.29
Lindbergh BB	Isopach	0.08	0.03	1.4	0.093	0.59	0.33	0.41
Lindbergh CC	Isopach	2.18	0.31	3.0	0.110	0.76	0.31	0.24
Lindbergh OO	Isopach	0.24	0.09	1.6	0.075	0.54	0.30	0.46
Lindbergh XX	Isopach	0.32	0.09	1.9	0.086	0.62	0.30	0.38
Lindbergh YY	Isopach	3.94	0.39	4.0	0.117	0.81	0.31	0.19
Frog Lake/ Lindbergh C	Isopach	9.95	1.07	3.7	0.119	0.79	0.32	0.21
Frog Lake/ Beaverdam A	Isopach	3.85	0.55	2.8	0.119	0.73	0.34	0.27
Lindbergh/ St. Paul A	Isopach	9.58	0.81	4.6	0.121	0.80	0.32	0.20
Beaverdam B	Isopach	84.40	9.49	3.5	0.121	0.77	0.33	0.23
Beaverdam G	Isopach	1.46	0.25	2.4	0.115	0.76	0.32	0.24
Beaverdam H	Isopach	1.65	0.31	2.1	0.120	0.74	0.34	0.26
Cold Lake B	Isopach	2.73	0.56	2.0	0.116	0.71	0.34	0.29
Wolf Lake D	Isopach	23.34	2.64	3.1	0.139	0.82	0.35	0.18
Lower Grd Rap Channel Sd								
Beaverdam F	Isopach	26.72	0.86	10.4	0.145	0.83	0.36	0.17
Wolf Lake F	Isopach	101.14	3.39	10.3	0.140	0.83	0.35	0.17
Lower Grand Rapids 4								
Frog Lake G	Isopach	9.15	0.97	3.6	0.124	0.79	0.33	0.21
Frog Lake I	Isopach	15.37	1.52	4.0	0.121	0.80	0.32	0.20
Frog Lake J	Isopach	1.49	0.21	2.8	0.118	0.78	0.32	0.22
Frog Lake K	Isopach	0.80	0.06	4.3	0.146	0.93	0.33	0.07
Frog Lake L	Isopach	0.60	0.11	2.1	0.121	0.80	0.32	0.20
Frog Lake M	Isopach	1.04	0.21	2.2	0.107	0.71	0.32	0.29
Frog Lake N	Isopach	2.88	0.34	3.1	0.129	0.82	0.33	0.18
Frog Lake P	Isopach	1.97	0.22	3.2	0.135	0.86	0.33	0.14
Frog Lake Q	Isopach	1.43	0.25	2.6	0.102	0.73	0.30	0.27
Frog Lake T	Isopach	0.25	0.06	1.7	0.122	0.78	0.33	0.22
Frog Lake NN	Isopach	5.41	0.42	5.8	0.104	0.72	0.31	0.28
Frog Lake PP	Isopach	0.13	0.03	2.4	0.086	0.57	0.32	0.43

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Table B.2 (*continued*)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in-place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation mass (fraction)	Bitumen saturation pore volume (fraction)	Porosity (fraction)	Water saturation (fraction)
Lindbergh B	Isopach	17.65	1.97	3.5	0.121	0.80	0.32	0.20
Lindbergh C	Isopach	6.85	0.93	3.1	0.113	0.75	0.32	0.25
Lindbergh D	Isopach	3.29	0.45	3.1	0.102	0.76	0.31	0.24
Lindbergh E	Isopach	3.24	0.50	2.7	0.115	0.79	0.31	0.21
Lindbergh H	Isopach	1.95	0.33	2.5	0.109	0.75	0.31	0.25
Lindbergh I	Isopach	1.44	0.25	2.5	0.109	0.75	0.31	0.25
Lindbergh J	Isopach	3.54	0.56	2.7	0.110	0.76	0.31	0.24
Lindbergh DD	Isopach	0.31	0.08	2.0	0.092	0.61	0.32	0.39
Lindbergh EE	Isopach	0.05	0.10	2.2	0.009	0.73	0.03	0.27
Lindbergh FF	Isopach	1.50	0.26	2.4	0.115	0.76	0.32	0.24
Lindbergh GG	Isopach	0.19	0.04	2.3	0.098	0.60	0.34	0.40
Lindbergh HH	Isopach	0.80	0.17	2.4	0.090	0.62	0.31	0.38
Lindbergh II	Isopach	0.20	0.04	2.6	0.089	0.59	0.32	0.41
Lindbergh JJ	Isopach	6.99	0.83	3.3	0.119	0.79	0.32	0.21
Lindbergh KK	Isopach	0.63	0.13	2.2	0.105	0.67	0.33	0.33
Lindbergh MM	Isopach	10.79	1.30	3.4	0.116	0.77	0.32	0.23
Lindbergh NN	Isopach	2.73	0.38	2.9	0.119	0.76	0.33	0.24
Lindbergh PP	Isopach	2.67	0.34	3.7	0.099	0.71	0.30	0.29
Lindbergh QQ	Isopach	0.79	0.14	2.4	0.107	0.80	0.29	0.20
Lindbergh RR	Isopach	0.05	0.02	1.4	0.089	0.64	0.30	0.36
Lindbergh SS	Isopach	3.12	0.29	4.7	0.110	0.70	0.33	0.30
Lindbergh UU	Isopach	0.57	0.10	2.4	0.113	0.75	0.32	0.25
Lindbergh ZZ	Isopach	10.13	1.10	3.8	0.113	0.78	0.31	0.22
Lindbergh EEE	Isopach	0.56	0.05	4.2	0.129	0.82	0.33	0.18
Lindbergh FFF	Isopach	3.81	0.54	2.7	0.127	0.80	0.33	0.20
Lindbergh GGG	Isopach	1.42	0.22	2.4	0.129	0.81	0.33	0.19
Lindbergh HHH	Isopach	2.21	0.27	3.0	0.129	0.82	0.33	0.18
Lindbergh JJJ	Isopach	2.20	0.27	3.0	0.127	0.84	0.32	0.16
Beaverdam C	Isopach	24.01	2.69	3.5	0.119	0.79	0.32	0.21
Cold Lake C	Isopach	4.22	0.77	2.2	0.117	0.72	0.34	0.28
Lindbergh/ St. Paul B	Isopach	9.63	1.22	3.4	0.110	0.73	0.32	0.27

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Table B.2 (*continued*)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in-place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation mass (fraction)	Bitumen saturation pore volume (fraction)	Porosity (fraction)	Water saturation (fraction)
Lower Grand Rapids 5								
Lindbergh AAA	Isopach	2.51	0.40	3.1	0.093	0.70	0.29	0.30
Lindbergh BBB	Isopach	0.29	0.10	1.6	0.083	0.62	0.29	0.38
Lindbergh CCC	Isopach	0.11	0.04	1.6	0.080	0.60	0.29	0.40
St. Paul A	Isopach	1.93	0.32	3.1	0.089	0.64	0.30	0.36
St. Paul B	Isopach	0.24	0.06	2.2	0.084	0.63	0.29	0.37
Lloydminster								
Frog Lake A	Isopach	1.34	0.17	3.9	0.097	0.62	0.33	0.38
Frog Lake B	Isopach	4.63	0.54	4.4	0.091	0.63	0.31	0.37
Frog Lake C	Isopach	2.85	0.38	3.6	0.100	0.64	0.33	0.36
Lindbergh D	Isopach	3.65	0.54	2.8	0.116	0.74	0.33	0.26
Lindbergh F	Isopach	2.91	0.48	3.6	0.078	0.56	0.30	0.44
Lindbergh G	Isopach	1.01	0.14	4.0	0.085	0.61	0.30	0.39
Lindbergh H	Isopach	28.27	2.31	5.1	0.113	0.75	0.32	0.25
Lindbergh I	Isopach	7.66	0.52	5.6	0.123	0.85	0.31	0.15
Lindbergh J	Isopach	0.68	0.21	1.4	0.109	0.72	0.32	0.28
Beaverdam A	Isopach	128.78	6.39	8.9	0.107	0.71	0.32	0.29
Frog Lake/ Lindbergh A	Isopach	5.31	0.59	4.6	0.091	0.63	0.31	0.37
Lindbergh/ St. Paul B	Isopach	60.39	2.43	8.9	0.133	0.85	0.33	0.15
Lindbergh/ St. Paul C	Isopach	3.81	0.34	4.7	0.113	0.75	0.32	0.25
Lindbergh/ Beaverdam A	Isopach	44.56	3.16	5.5	0.120	0.83	0.31	0.17
Lind./Beaver./ Bonny. A	Isopach	511.25	19.81	8.9	0.138	0.85	0.34	0.15
Cold Lake A	Isopach	15.74	1.29	4.7	0.125	0.74	0.35	0.26
Clearwater								
350–625	Isopach	9 422.00	433.00	11.8	0.089	0.59	0.31	0.41
Wabiskaw-McMurray								
Northern	Isopach	2 161.00	132.00	8.9	0.087	0.64	0.29	0.36
Central-Southern	Building Block	1 439.00	285.00	4.1	0.057	0.51	0.25	0.49
Cummings 1								
Frog Lake A	Isopach	4.07	0.69	2.4	0.116	0.83	0.30	0.17
Frog Lake B	Isopach	1.52	0.17	3.4	0.124	0.82	0.32	0.18

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Table B.2 (*continued*)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in-place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation mass (fraction)	Bitumen saturation pore volume (fraction)	Porosity (fraction)	Water saturation (fraction)
Frog Lake C	Isopach	5.20	0.66	3.0	0.122	0.81	0.32	0.19
Frog Lake/ Lindbergh A	Isopach	38.28	3.76	3.9	0.122	0.84	0.31	0.16
Lindbergh/ St. Paul A	Isopach	273.08	29.62	3.9	0.109	0.78	0.30	0.22
Cummings 2								
St. Paul B	Isopach	1.32	0.18	3.2	0.106	0.76	0.30	0.24
Lindbergh/ St. Paul B	Isopach	221.36	20.89	4.2	0.117	0.81	0.31	0.19
McMurray								
Lindbergh A	Isopach	89.87	5.49	6.1	0.127	0.84	0.32	0.16
Lindbergh B	Isopach	0.09	0.02	2.4	0.083	0.68	0.27	0.32
Lindbergh C	Isopach	42.72	5.83	3.1	0.112	0.77	0.31	0.23
Lindbergh D	Isopach	0.94	0.11	3.2	0.125	0.86	0.31	0.14
Lindbergh E	Isopach	0.07	0.05	0.7	0.088	0.69	0.28	0.31
Lindbergh F	Isopach	8.11	0.55	6.7	0.103	0.71	0.31	0.29
St. Paul A	Isopach	0.04	0.02	1.2	0.090	0.62	0.31	0.38
Peace River								
Bluesky-Gething								
300–800+	Isopach	10 968.00	1 016.00	6.1	0.081	0.68	0.26	0.32
Belloy								
675–700	Building Block	282.00	26.00	8.0	0.078	0.64	0.27	0.36
Upper Debolt								
500–800	Building Block	1 830.00	100.00	13.0	0.050	0.61	0.19	0.39
Lower Debolt								
500–800	Building Block	5 970.00	202.00	29.0	0.051	0.67	0.18	0.33
Shunda								
500–800	Building Block	2 510.00	143.00	14.0	0.053	0.52	0.23	0.48
Total		**293 124.67**						

Table B.3 Conventional crude oil reserves as of each year-end (10^6 m^3)

Year	Changes to initial established reserves: New discoveries	EOR additions	Development	Revisions	Net changes	Initial established reserves	Cumulative production	Remaining established reserves
1968	62.0				119.8	1 643.1	430.3	1 212.8
1969	40.5				54.5	1 697.5	474.7	1 222.8
1970	8.4				36.7	1 734.4	526.5	1 207.9
1971	14.0				22.1	1 756.5	582.9	1 173.6
1972	10.8				20.0	1 776.0	650.0	1 126.0
1973	5.1				9.2	1 785.7	733.7	1 052.0
1974	4.3				38.5	1 824.2	812.7	1 011.5
1975	1.6				7.0	1 831.1	880.2	950.9
1976	2.5				-18.6	1 812.5	941.2	871.3
1977	4.8				19.1	1 831.6	1 001.6	830.0
1978	24.9				24.4	1 856.1	1 061.6	794.5
1979	19.2				34.3	1 890.3	1 130.1	760.2
1980	9.0				22.8	1 913.2	1 193.3	719.9
1981	15.0	7.2			32.6	1 945.8	1 249.8	696.0
1982	16.8	6.6			6.9	1 952.8	1 303.4	649.4
1983	21.4	17.9			64.1	2 016.8	1 359.0	657.8
1984	29.1	24.1			42.0	2 058.9	1 418.2	640.7
1985	32.7	21.6			64.0	2 123.0	1 474.5	648.5
1986	28.6	24.6	16.6	-30.7	39.1	2 162.4	1 527.7	634.7
1987	20.9	10.5	12.8	-11.2	33.0	2 195.4	1 581.6	613.8
1988	18.0	16.5	18.0	-15.8	36.7	2 231.7	1 638.8	592.9
1989	17.0	7.8	12.9	-16.3	21.4	2 253.1	1 692.6	560.5
1990	13.0	8.4	7.2	-25.6	3.0	2 256.1	1 745.7	510.4
1991	10.2	9.1	10.6	-20.5	9.4	2 265.6	1 797.1	468.5
1992	9.0	2.8	12.3	3.0	27.1	2 292.7	1 850.7	442.0
1993	7.3	7.9	14.2	9.8	39.2	2 331.9	1 905.1	426.8
1994	10.5	5.7	11.1	-22.6	4.7	2 336.5	1 961.7	374.8
1995	10.2	9.2	20.8	14.8	55.0	2 391.6	2 017.5	374.1
1996	9.7	6.1	16.3	-9.5	22.6	2 414.1	2 072.3	341.8
1997	8.5	4.2	16.1	8.7	37.5	2 451.6	2 124.8	326.8
1998	8.9	2.9	17.5	9.2	38.5	2 490.1	2 174.9	315.2
1999	5.6	2.1	7.2	16.6	31.5	2 521.5	2 219.9	301.6
2000	7.8	1.5	13.4	10.0	32.8	2 554.3	2 262.9	291.4
2001	9.1	0.8	13.6	5.2	28.6	2 583.0	2 304.7	278.3

(continued on next page)

Table B.3 (*continued*)

Year	Changes to initial established reserves					Initial established reserves	Cumulative production	Remaining established reserves
	New discoveries	EOR additions	Development	Revisions	Net changes			
2002	7.0	0.6	8.1	4.6	20.2	2 603.3	2 343.0	260.3
2003	6.9	1.0	5.9	17.1	30.8	2 634.0	2 380.1	253.9
2004	6.1	3.2	8.0	13.6	30.9	2 664.9	2 415.7	249.2
2005	5.5	1.2	13.2	18.9	38.8	2 703.7	2 448.9	254.8
2006	8.2	1.9	14.8	2.2	27.1	2 730.8	2 480.7	250.1
2007	6.8	2.2	11.8	-0.2	20.6	2 751.6	2 510.9	240.7
2008	6.9	6.2	9.3	-0.7	21.7	2 773.1	2 540.1	233.0
2009	4.0	4.8	7.4	+5.8	21.8	2 794.9	2 566.5	228.4
2010	3.8	5.8	23.5	+1.7	34.8	2 829.7	2 592.8	236.9
2011	4.0	6.4	14.0	+9.0	33.5	2 863.2	2 617.3	245.9
2012	5.8	2.2	52.9	-2.4	58.5	2 921.7	2 652.5	269.2
2013	4.9	2.2	30.8	+10.1	50.0	2 970.0	2 687.0	283.4
2014	4.3	6.8	26.7	+2.2	40.0	3 010.0	2 721.8	288.2

Table B.4 Summary of marketable natural gas reserves as of each year-end (10^9 m^3)

	Changes to initial established reserves							
Year	New discoveries	Development	Revisions	Net changes	Initial established reserves	Cumulative production	Remaining established reserves[a]	Remaining reserves at 37.4 MJ/m³
1966				40.7	1 251.0	178.3	1 072.6	1 142.5
1967				73.9	1 324.9	205.8	1 119.1	1 189.6
1968				134.6	1 459.5	235.8	1 223.6	1 289.0
1969				87.5	1 547.0	273.6	1 273.4	1 342.6
1970				46.2	1 593.2	313.8	1 279.4	1 352.0
1971				45.4	1 638.6	362.3	1 276.3	1 346.9
1972				45.2	1 683.9	414.7	1 269.1	1 337.6
1973				183.4	1 867.2	470.7	1 396.6	1 464.5
1974				147.0	2 014.3	527.8	1 486.5	1 550.2
1975				20.8	2 035.1	584.3	1 450.8	1 512.8
1976				105.6	2 140.7	639.0	1 501.7	1 563.9
1977				127.6	2 268.2	700.0	1 568.3	1 630.3
1978				163.3	2 431.6	766.3	1 665.2	1 730.9
1979				123.2	2 554.7	836.4	1 718.4	1 786.2
1980				94.2	2 647.1	900.2	1 747.0	1 812.1
1981				117.0	2 764.1	968.8	1 795.3	1 864.8
1982				118.7	2 882.8	1 029.7	1 853.1	1 924.6
1983				39.0	2 921.8	1 095.6	1 826.2	1 898.7
1984				40.5	2 962.3	1 163.9	1 798.4	1 872.2
1985				42.6	3 004.9	1 236.7	1 768.3	1 840.0
1986				21.8	3 026.7	1 306.6	1 720.1	1 790.3
1987				0.0	3 026.7	1 375.0	1 651.7	1 713.7
1988				64.6	3 091.3	1 463.5	1 627.7	1 673.7
1989				107.8	3 199.0	1 549.3	1 648.7	1 689.2
1990				87.8	3 286.8	1 639.4	1 647.4	1 694.2
1991				57.6	3 344.4	1 718.2	1 626.2	1 669.7
1992				72.5	3 416.9	1 822.1	1 594.7	1 637.6
1993				58.6	3 475.5	1 940.5	1 534.9	1 573.7
1994				74.2	3 549.7	2 059.3	1 490.3	1 526.3
1995				123.0	3 672.7	2 183.9	1 488.8	1 521.8
1996				10.9	3 683.5	2 305.5	1 378.1	1 410.1
1997				33.1	3 716.6	2 432.7	1 283.9	1 314.4
1998				93.0	3 809.6	2 569.8	1 239.9	1 269.3
1999	38.5	40.5	30.7	109.7	3 919.3	2 712.1	1 207.2	1 228.7

(continued on next page)

Table B.4 (*continued*)

Year	Changes to initial established reserves: New discoveries	Development	Revisions	Net changes	Initial established reserves	Cumulative production	Remaining established reserves[a]	Remaining reserves at 37.4 MJ/m³
2000	50.3	76.5	17.5	144.3	4 063.5	2 852.8	1 210.7	1 221.1
2001	62.5	32.4	21.5	116.4	4 179.9	2 995.5	1 184.4	1 276.8
2002	83.4	60.4	-10.2	133.6	4 313.5	3 142.1	1 171.4	1 258.0
2003	89.4	53.8	-56.0	87.2	4 400.7	3 278.6	1 122.2	1 166.7
2004	55.5	64.5	25.9	145.9	4 546.6	3 419.6	1 127.0	1 172.3
2005	40.4	49.9	35.0	125.7	4 672.4	3 552.4	1 120.0	1 164.0
2006	83.4	48.4	-5.4	126.3	4 798.7	3 683.5	1 115.2	1 136.3
2007	71.0	30.0	-6.4	94.6	4 893.3	3 823.9	1 069.3	1 112.2
2008	69.3	31.3	54.8	155.4	5 048.7	3 950.5	1 098.2	1 142.3
2009	43.1	20.1	18.8	82.0	5 130.7	4 075.0	1 055.7	1 098.0
2010	24.3	25.3	33.2	82.8	5 213.5	4 188.4	1 025.1	1 065.7
2011	20.8	24.0	24.7	69.5	5 283.1	4 338.0	945.1	987.0
2012	16.2	8.0	33.8	58.0	5 341.1	4 425.4	915.7	957.2
2013	20.9	12.4	46.2	79.5	5 420.6	4 523.0	897.5	941.0
2014	13.5	15.5	37.3	66.3	5 486.8	4 621.5	865.3	907.8

[a] At field plant.

Table B.5 Natural gas reserves of multifield pools as of December 31, 2014

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
MFP8515 Banff	
Haro MFP8515 Banff	72
Rainbow MFP8515 Banff	4
Rainbow South MFP8515 Banff	62
Total	138
MFP8516 Viking	
Fenn West MFP8516 Viking	5
Fenn-Big Valley MFP8516 Viking	2
Total	7
MFP8524 Halfway	
Valhalla MFP8524 Halfway	2 023
Wembley MFP8524 Halfway	1 867
Total	3 890
MFP8525 Colony	
Ukalta MFP8525 Colony	0
Whitford MFP8525 Colony	0
Total	0
MFP8528 Bluesky	
Rainbow MFP8528 Bluesky	127
Sousa MFP8528 Bluesky	496
Total	623
MFP8541 Second White Specks	
Cherry MFP8541 2WS	23
Granlea MFP8541 2WS	21
Taber MFP8541 2WS	97
Total	141
Commingled MFP9503	
Hairy Hill Commingled MFP9503	195
Willingdon Commingled MFP9503	9
Total	204
Commingled MFP9504	
Alix Commingled MFP9504	329
Bashaw Commingled MFP9504	1 515
Buffalo Lake Commingled MFP9504	3
Chigwell Commingled MFP9504	60
Chigwell North Commingled MFP9504	183
Clive Commingled MFP9504	347
Donalda Commingled MFP9504	73
Dorenlee Commingled MFP9504	1
Ferintosh Commingled MFP9504	1
Haynes Commingled MFP9504	62
Lacombe Commingled MFP9504	5
Malmo Commingled MFP9504	295
Nevis Commingled MFP9504	1 195
Wood River Commingled MFP9504	100
Total	4 169

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Commingled MFP9505	
Bigoray Commingled MFP9505	134
Pembina Commingled MFP9505	551
Total	685
Commingled MFP9506	
Bonnie Glen Commingled MFP9506	15
Ferrybank Commingled MFP9506	140
Total	155
Commingled MFP9508	
Fairydell-Bon Accord Commingled MFP9508	57
Peavey Commingled MFP9508	1
Redwater Commingled MFP9508	1 311
Total	1 369
Commingled MFP9509	
Albers Commingled MFP9509	3
Beaverhill Lake Commingled MFP9509	401
Bellshill Lake Commingled MFP9509	25
Birch Commingled MFP9509	5
Bruce Commingled MFP9509	566
Dinant Commingled MFP9509	0
Edberg Commingled MFP9509	0
Fort Saskatchewan Commingled MFP9509	35
Holmberg Commingled MFP9509	240
Kelsey Commingled MFP9509	35
Killam Commingled MFP9509	190
Killam North Commingled MFP9509	48
Mannville Commingled MFP9509	223
Sedgewick Commingled MFP9509	4
Viking-Kinsella Commingled MFP9509	860
Wainwright Commingled MFP9509	284
Total	2 919
Commingled MFP9510	
Chickadee Commingled MFP9510	2 066
Fox Creek Commingled MFP9510	730
Kaybob South Commingled MFP9510	19
Windfall Commingled MFP9510	0
Total	2 815
Commingled MFP9511	
Hudson Commingled MFP9511	29
Sedalia Commingled MFP9511	139
Total	168

(continued on next page)

Table B.5 (*continued*)

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Commingled MFP9512	
Inland Commingled MFP9512	10
Royal Commingled MFP9512	0
Total	10
Commingled MFP9513	
Elmworth Commingled MFP9513	14 385
Sinclair Commingled MFP9513	3 839
Total	18 224
Commingled MFP9514	
Connorsville Commingled MFP9514	525
Wintering Hills Commingled MFP9514	51
Total	576
Commingled MFP9515	
Craigmyle Commingled MFP9515	5
Dowling Lake Commingled MFP9515	4
Garden Plains Commingled MFP9515	624
Hanna Commingled MFP9515	419
Provost Commingled MFP9515	2 693
Racosta Commingled MFP9515	60
Richdale Commingled MFP9515	57
Stanmore Commingled MFP9515	22
Sullivan Lake Commingled MFP9515	38
Watts Commingled MFP9515	33
Total	3 955
Commingled MFP9516	
Knopcik Commingled MFP9516	231
Valhalla Commingled MFP9516	18
Total	249
Commingled MFP9517	
Comrey Commingled MFP9517	10
Conrad Commingled MFP9517	75
Forty Mile Commingled MFP9517	37
Pendant D'Oreille Commingled MFP9517	714
Smith Coulee Commingled MFP9517	240
Total	1 076
Commingled MFP9520	
Gadsby Commingled MFP9520	2
Leahurst Commingled MFP9520	26
Total	28
Commingled MFP9522	
Enchant Commingled MFP9522	178
Grand Forks Commingled MFP9522	5
Little Bow Commingled MFP9522	1
Retlaw Commingled MFP9522	257
Vauxhall Commingled MFP9522	12
Total	453

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Commingled MFP9524	
Stirling Commingled MFP9524	73
Warner Commingled MFP9524	9
Total	82
Commingled MFP9525	
Resthaven Commingled MFP9525	1 782
Smoky Commingled MFP9525	692
Total	2 474
Commingled MFP9526	
Garrington Commingled MFP9526	38
Innisfail Commingled MFP9526	14
Markerville Commingled MFP9526	155
Medicine River Commingled MFP9526	143
Penhold Commingled MFP9526	6
Sylvan Lake Commingled MFP9526	522
Tindastoll Commingled MFP9526	30
Total	908
Commingled MFP9527	
Crystal Commingled MFP9527	18
Gilby Commingled MFP9527	27
Minnehik-Buck Lake Commingled MFP9527	140
Westerose South Commingled MFP9527	161
Wilson Creek Commingled MFP9527	194
Total	540
Commingled MFP9529	
Ansell Commingled MFP9529	12 531
Berland River Commingled MFP9529	20
Berland River West Commingled MFP9529	49
Edson Commingled MFP9529	1 499
Elmworth Commingled MFP9529	355
Fir Commingled MFP9529	9 256
Kaybob South Commingled MFP9529	6 341
Medicine Lodge Commingled MFP9529	1 074
Minehead Commingled MFP9529	2 182
Nosehill Commingled MFP9529	113
Red Rock Commingled MFP9529	3 082
Sundance Commingled MFP9529	13 958
Wapiti Commingled MFP9529	29 010
Wild River Commingled MFP9529	17 911
Wildhay Commingled MFP9529	320
Total	97 701

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Table B.5 (*continued*)

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Commingled MFP9530	
Cygnet Commingled MFP9530	10
Gilby Commingled MFP9530	32
Prevo Commingled MFP9530	39
Total	81
Commingled MFP9531	
Nosehill Commingled MFP9531	934
Pine Creek Commingled MFP9531	896
Sundance Commingled MFP9531	11
Total	1 841
Commingled MFP9532	
Grizzly Commingled MFP9532	104
Waskahigan Commingled MFP9532	71
Total	175
Commingled MFP9533	
Bigstone Commingled MFP9533	113
Placid Commingled MFP9533	681
Total	794
Commingled MFP9534	
Jenner Commingled MFP9534	2
Princess Commingled MFP9534	0
Total	2
Commingled MFP9536	
Chinook Commingled MFP9536	92
Dobson Commingled MFP9536	13
Heathdale Commingled MFP9536	26
Kirkwall Commingled MFP9536	8
Sedalia Commingled MFP9536	2
Sounding Commingled MFP9536	64
Stanmore Commingled MFP9536	55
Total	260
Commingled MFP9537	
Ferrier Commingled MFP9537	239
Pembina Commingled MFP9537	1 314
Willesden Green Commingled MFP9537	559
Total	2 112
Commingled MFP9538	
Carrot Creek Commingled MFP9538	620
Edson Commingled MFP9538	343
Pembina Commingled MFP9535	96
Rosevear Commingled MFP9538	55
Total	1 114
Commingled MFP9501 (Southeast Alberta Gas System)	
Aerial Commingled MFP9501	71
Alderson Commingled MFP9501	13 189
Armada Commingled MFP9501	28
Atlee-Buffalo Commingled MFP9501	365

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Badger Commingled MFP9501	29
Bantry Commingled MFP9501	11 423
Berry Commingled MFP9501	579
Bindloss Commingled MFP9501	610
Blackfoot Commingled MFP9501	354
Bow Island Commingled MFP9501	230
Brooks Commingled MFP9501	230
Carbon Commingled MFP9501	559
Cavalier Commingled MFP9501	415
Cessford Commingled MFP9501	5 178
Chain Commingled MFP9501	161
Chauncey Commingled MFP9501	52
Connemara Commingled MFP9501	3
Connorsville Commingled MFP9501	567
Countess Commingled MFP9501	33 208
Craigmyle Commingled MFP9501	666
Crossfield Commingled MFP9501	34
Davey Commingled MFP9501	237
Delia Commingled MFP9501	335
Drumheller Commingled MFP9501	1 430
Elkwater Commingled MFP9501	664
Elnora Commingled MFP9501	233
Enchant Commingled MFP9501	9
Entice Commingled MFP9501	6 228
Erskine Commingled MFP9501	24
Ewing Lake Commingled MFP9501	83
Eyremore Commingled MFP9501	590
Fenn West Commingled MFP9501	140
Fenn-Big Valley Commingled MFP9501	794
Gadsby Commingled MFP9501	476
Gartley Commingled MFP9501	4
Ghost Pine Commingled MFP9501	603
Gleichen Commingled MFP9501	321
Hector Commingled MFP9501	39
Herronton Commingled MFP9501	810
High River Commingled MFP9501	9
Hussar Commingled MFP9501	5 792
Huxley Commingled MFP9501	351
Jenner Commingled MFP9501	1 697
Joffre Commingled MFP9501	5
Johnson Commingled MFP9501	99
Jumpbush Commingled MFP9501	374
Kitsim Commingled MFP9501	32
Lathom Commingled MFP9501	2 054
Leckie Commingled MFP9501	440
Leo Commingled MFP9501	213

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Table B.5 (*continued*)

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Little Bow Commingled MFP9501	8
Lomond Commingled MFP9501	66
Lone Pine Creek Commingled MFP9501	140
Long Coulee Commingled MFP9501	7
Majorville Commingled MFP9501	429
Matziwin Commingled MFP9501	727
Mcgregor Commingled MFP9501	17
Medicine Hat Commingled MFP9501	39 009
Michichi Commingled MFP9501	250
Mikwan Commingled MFP9501	401
Milo Commingled MFP9501	37
Newell Commingled MFP9501	1 757
Okotoks Commingled MFP9501	75
Pageant Commingled MFP9501	7
Parflesh Commingled MFP9501	767
PenholdCommingled MFP9501	2
Pollockville Commingled MFP9501	1
Princess Commingled MFP9501	7 417
Queenstown Commingled MFP9501	40
Rainier Commingled MFP9501	8
Redland Commingled MFP9501	529
Rich Commingled MFP9501	265
Rockyford Commingled MFP9501	1 537
Ronalane Commingled MFP9501	58
Rowley Commingled MFP9501	369
Rumsey Commingled MFP9501	15
Seiu Lake Commingled MFP9501	419
Shouldice Commingled MFP9501	552
Silver Commingled MFP9501	7
Stettler Commingled MFP9501	75
Stettler North Commingled MFP9501	25
Stewart Commingled MFP9501	470
Suffield Commingled MFP9501	10 667
Swalwell Commingled MFP9501	388
Three Hills Creek Commingled MFP9501	639
Trochu Commingled MFP9501	179
Twining Commingled MFP9501	1 674
Verger Commingled MFP9501	4 170
Vulcan Commingled MFP9501	60
Watts Commingled MFP9501	1
Wayne-Rosedale Commingled MFP9501	6 798
Wimborne Commingled MFP9501	629
Wintering Hills Commingled MFP9501	2 601
Workman Commingled MFP9501	61
Total	**175 390**

Table B.6 Remaining raw ethane reserves as of December 31, 2014

Field	Remaining reserves of marketable gas (10^6 m^3)	Ethane content (mol/mol)	Remaining established reserves of raw ethane Gas (10^6 m^3)	Remaining established reserves of raw ethane Liquid (10^3 m^3)
Ansell	15 526	8.2	1 394	4 954
Ante Creek North	2 857	10.5	342	1 216
Brazeau River	8 397	7.2	714	2 537
Caroline	5 046	8.7	546	1 943
Edson	7 290	8.6	682	2 423
Elmworth	21 620	6.1	1 440	5 120
Ferrier	10 762	8.2	983	3 495
Fir	10 287	5.7	641	2 280
Gilby	4 199	7.8	368	1 305
Golden Spike	2 224	12.7	414	1 470
Harmattan East	6 992	8.5	670	2 382
Judy Creek	3 416	15.6	666	2 368
Kakwa	17 211	8.4	1 601	5 690
Kaybob	3 743	9.3	396	1 408
Kaybob South	12 672	7.6	1 090	3 876
Leduc-Woodbend	2 659	14.1	446	1 586
Pembina	22 994	7.9	2 577	9 159
Pine Creek	5 769	6.8	458	1 627
Pouce Coupe South	13 979	4.8	745	2 648
Rainbow	8 679	10.0	1 174	4 173
Rainbow South	2 480	9.9	360	1 280
Redwater	3 358	9.5	455	1 618
Simonette	2 855	8.5	342	1 216
Sinclair	7 353	5.2	418	1 486
Smoky	5 162	7.2	406	1 445
Sundance	15 582	6.7	1 148	4 081
Swan Hills South	3 660	16.0	804	2 860
Sylvan Lake	3 590	7.8	314	1 116
Valhalla	9 062	7.2	716	2 545
Wapiti	32 808	5.5	1 940	6 898
Wayne-Rosedale	8 203	3.4	296	1 053
Wembley	3 175	10.0	386	1 374
Westerose South	4 548	8.2	414	1 470
Wild River	18 524	7.2	1 454	5 170
Willesden Green	18 310	8.8	2 103	7 478

(continued on next page)

Table B.6 (*continued*)

Field	Remaining reserves of marketable gas (10^6 m^3)	Ethane content (mol/mol)	Remaining established reserves of raw ethane	
			Gas (10^6 m^3)	Liquid (10^3 m^3)
Wilson Creek	4 059	7.5	341	1 212
Subtotal	**329 051**	**7.7**	**29 242**	**103 959**
All other fields	**536 271**	**3.1**	**18 126**	**64 590**
Total	**865 322**	**5.2**[a]	**47 368**	**168 549**

[a] Volume weighted average.

Table B.7 Remaining raw reserves of natural gas liquids as of December 31, 2014

Field	Remaining reserves of marketable gas (10^6 m^3)	(10^3 m^3 liquid)			
		Propane	Butanes	Pentanes plus	Total liquids
Ansell	15 526	2 175	1 131	2 304	5 610
Ante Creek North	2 857	669	324	594	1 587
Brazeau River	8 397	1 214	713	1 423	3 351
Caroline	5 046	820	446	623	1 889
Dunvegan	5202	434	252	425	1 111
Edson	7 290	851	364	362	1 576
Elmworth	21 620	1 785	879	884	3 548
Fenn-Big Valley	2 114	904	392	105	1 401
Ferrier	10 762	1 527	731	745	3 002
Fir	10 287	868	419	571	1 857
Garrington	2 649	407	210	275	892
Gilby	4 199	642	326	359	1 326
Gold Creek	3 274	366	190	283	839
Golden Spike	2 224	1 211	160	563	1 934
Harmattan East	6 992	1 035	583	834	2 452
Judy Creek	3 416	1 603	662	376	2 641
Kakwa	17 211	2 484	1 142	976	4 601
Karr	3 605	449	226	218	893
Kaybob	3 743	744	356	376	1 476
Kaybob South	12 672	1 801	918	987	3 706
Leduc-Woodbend	2 659	1 390	815	463	2 668
Pembina	22 994	5 732	2 927	2 112	10 771
Pine Creek	5 769	747	352	376	1 475
Pouce Coupe South	13 979	964	541	569	2 074
Provost	7 825	556	367	262	1 186
Rainbow	8 679	1 815	992	1 024	3 832
Rainbow South	2 480	648	297	330	1 275
Redwater	3 358	1 218	765	303	2 286
Ricinus	3 526	441	219	370	1 029
Simonette	2 855	592	341	344	1 276
Sinclair	7 353	524	225	225	974
Smoky	5 162	568	262	207	1 038
Sundance	15 582	1 427	639	1 044	3 110
Swan Hills South	3 660	1 928	888	406	3 222

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Table B.7 (*continued*)

Field	Remaining reserves of marketable gas (10^6 m^3)	(10^3 m^3 liquid)			
		Propane	Butanes	Pentanes plus	Total liquids
Sylvan Lake	3 590	495	240	218	953
Valhalla	9 062	1 217	641	857	2 715
Virginia Hills	1 170	628	204	78	910
Wapiti	32 808	2 121	825	774	3 720
Waterton	3 761	172	152	936	1 259
Wayne-Rosedale	8 203	510	275	330	1 115
Wembley	3 175	756	437	825	2 018
Westerose South	4 548	771	381	384	1 536
Wild River	18 524	1 782	752	1 054	3 587
Willesden Green	18 310	4 231	2 119	1 620	7 970
Wilson Creek	4 059	558	309	408	1 275
Subtotal	**362 177**	**53 778**	**26 387**	**28 799**	**108 963**
All other fields	**503 145**	**21 544**	**12 211**	**13 869**	**47 624**
Total	**865 322**	**75 321**	**38 598**	**42 668**	**156 587**

Appendix C Basic Data Tables

AER staff developed the databases used to estimate the reserves for this report and the electronic data file that accompanies this report (available for $546 from the AER's Order Fulfillment Team). Input has also been obtained from the National Energy Board (NEB). The crude oil and natural gas reserves data tables noted in the following sections present the official reserve estimates of both the AER and NEB for the province of Alberta.

The conventional oil and conventional natural gas reserves, and their respective basic data tables, for year-end 2014 are electronically available and formatted as Microsoft Excel spreadsheets. Individual oil and gas pool values are on the first worksheet of each spreadsheet. Oilfield and gas field/strike totals are on the second worksheet. Provincial totals for crude oil and natural gas are on the third worksheet. The pool names on the left side and the column headings at the top of the spreadsheets are locked into place for easy scrolling. All crude oil and natural gas pools are first listed alphabetically by field/strike name and then stratigraphically within the field, with the pools occurring in the youngest reservoir rock listed first. Additionally, the crude bitumen in-place resources and basic data listed in **Table B.1** and **Table B.2** of **Appendix B** are included in Excel format as an electronic data file.

Crude Oil Reserves and Basic Data

The crude oil reserves and basic data spreadsheet lists all nonconfidential pools in Alberta.

Reserves data for single- and multi-mechanism pools are in separate columns. The total is the sum of the multimechanism pool reserves data and can be used to determine field and provincial totals. The name of the mechanism type is displayed.

Provincial totals for light-medium and heavy oil pools are listed on a separate worksheet.

Natural Gas Reserves and Basic Data

The natural gas reserves and basic data spreadsheet lists all nonconfidential pools in Alberta.

Basic reserves data are in two columns: pools (individual, undefined, and total) and member pools (separate gas pools overlying a single oil pool or individual gas pools that have been commingled). The total is the sum of the reserves data for all of the related members. Individual pools have a sequence code of 000; undefined pools have a pool code ending in 98 and a unique pool sequence code other than 000; and the total records have a sequence code of 999. Member pools and the total record have the same pool code, with each member pool having a unique pool sequence code and the total record having a sequence code of 999.

Crude Bitumen Resources and Basic Data

The crude bitumen in-place resources and basic data spreadsheet is unchanged from the data tables in last year's report. The oil sands area, oil sands deposit, overburden/zone, oil sands sector/pool, and resource determination method are listed in separate columns. This data is the same as that listed in **Table B.1** and **Table B.2** of **Appendix B**.

General Abbreviations Used in the Reserves and Basic Data Files

ABAND	abandoned
ASSOC	associated gas
BELL	Belloy
BLAIR	Blairmore
BLSKY OR BLSK	Bluesky
BLUE	Blueridge
BNFF	Banff
BOW ISL or BI	Bow Island
BR	Belly River
BSL COLO	Basal Colorado
BSL MANN, BMNV or BMN	Basal Mannville
BSL QTZ	Basal Quartz
CADM or CDN	Cadomin
CARD	Cardium
CDOT	Cadotte
CH LK	Charlie Lake
CLWTR	Clearwater
CLY or COL	Colony
CMRS	Camrose
DBLT	Debolt
DETR	Detrital
ELRSL, ELERS or ELRS	Ellerslie
ELTN or ELK	Elkton
FALH	Falher
GEN PETE or GEN PET	General Petroleum
GETH or GET	Gething
GLAUC or GLC	Glauconitic
GLWD	Gilwood
GRD RAP or GRD RP	Grand Rapids
GSMT	Grosmont
ha	hectare
HFWY	Halfway
JUR or J	Jurassic
KB	kelly bushing
KISK	Kiskatinaw
KR	Keg River
LED	Leduc
LIV	Livingston
LLOYD	Lloydminster
LMNV, LMN or LM	Lower Mannville
LOW or L	lower

LUSC	Luscar
MANN or MN	Mannville
MCM	McMurray
MED HAT	Medicine Hat
MID or M	middle
MILK RIV	Milk River
MSKG	Muskeg
MSL	mean sea level
NGL	natural gas liquids
NIKA	Nikanassin
NIS	Nisku
NON ASSOC	nonassociated gas
NORD	Nordegg
NOTIK, NOTI or NOT	Notikewin
OST	Ostracod
PALL	Palliser
PEK	Pekisko
RK CK	Rock Creek
RUND or RUN	Rundle
SD	sandstone
SHUN	Shunda
SL PT	Slave Point
SPKY	Sparky
ST. ED	St. Edouard
SULPT	Sulphur Point
SW HL	Swan Hills
TV	Turner Valley
UIRE	Upper Ireton
UMNV, UMN or UM	Upper Mannville
UP or U	upper
VIK or VK	Viking
WAB	Wabamun
WBSK	Wabiskaw
WINT	Winterburn
1ST WHITE SPKS or 1WS	First White Specks
2WS	Second White Specks
SG	gas saturation
SHUN	Shunda
SL	surface loss
SL PT	Slave Point
SOLN	solution gas
SPKY	Sparky
ST. ED	St. Edouard

SULPT	Sulphur Point
SUSP	suspended
SW	water saturation
SW HL	Swan Hills
TEMP	temperature
TOT	total
TV	Turner Valley
TVD	true vertical depth
UIRE	Upper Ireton
UMNV, UMN or UM	Upper Mannville
UP or U	upper
VIK or VK	Viking
VOL	volume
WAB	Wabamun
WBSK	Wabiskaw
WINT	Winterburn
WTR DISP	water disposal
WTR INJ	water injection
1ST WHITE SPKS or 1WS	First White Specks
2WS	Second White Specks

Appendix D Drilling Activity in Alberta

Table D.1 Development and exploratory wells, pre-1972–2014; number drilled annually

	Development					Exploratory				Total			
		Crude bitumen											
Year	Successful oil	Commercial	Experimental	Gas	Total[a]	Successful oil	Crude bitumen[b]	Gas	Total[a]	Successful oil	Crude bitumen	Gas	Total[a]
Pre-1972	11 873	*	**	7 869	24 325	1 624	**	3 619	31 639	13 497	**	11 488	55 964
1972	438	*	**	672	1 468	69	**	318	1 208	507	**	990	2 676
1973	472	*	**	898	1 837	109	**	476	1 676	581	**	1 374	3 513
1974	553	*	**	1 222	2 101	82	**	446	1 388	635	**	1 668	3 489
1975	583	*	**	1 367	2 266	81	**	504	1 380	664	**	1 871	3 646
1976	440	*	**	2 044	2 887	112	**	1 057	2 154	552	**	3 101	5 041
1977	524	*	**	1 928	2 778	178	**	1 024	2 352	702	**	2 952	5 130
1978	708	*	**	2 091	3 186	236	**	999	2 387	944	**	3 090	5 573
1979	953	*	**	2 237	3 686	297	**	940	2 094	1 250	**	3 177	5 780
1980	1 229	*	**	2 674	4 425	377	**	1 221	2 623	1 606	**	3 895	7 048
1981	1 044	*	**	2 012	3 504	381	**	1 044	2 337	1 425	**	3 056	5 841
1982	1 149	*	**	1 791	3 353	414	**	620	1 773	1 563	**	2 411	5 126
1983	1 823	*	**	791	2 993	419	**	300	1 373	2 242	**	1 091	4 366
1984	2 255	*	**	911	3 724	582	**	361	1 951	2 837	**	1 272	5 675
1985	2 101	975	229	1 578	5 649	709	593	354	2 827	2 810	1 797	1 932	8 476
1986	1 294	191	75	660	2 783	452	171	311	1 726	1 746	437	971	4 509
1987	1 623	377	132	549	3 212	553	105	380	1 970	2 176	614	929	5 182
1988	1 755	660	54	871	4 082	526	276	610	2 535	2 281	990	1 481	6 617
1989	869	37	24	602	1 897	382	246	660	2 245	1 251	307	1 262	4 142
1990	804	69	30	715	1 999	401	122	837	2 308	1 205	221	1 552	4 307

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Table D.1 (*continued*)

Year	Development					Exploratory				Total			
	Successful oil	Crude bitumen		Gas	Total[a]	Successful oil	Crude bitumen[b]	Gas	Total[a]	Successful oil	Crude bitumen	Gas	Total[a]
		Commercial	Experimental										
1991	1 032	91	13	544	2 089	346	51	566	1 808	1 378	155	1 110	3 897
1992	1 428	101	2	335	2 306	368	13	387	1 497	1 796	116	722	3 803
1993	2 402	290	6	1 565	4 919	549	5	763	2 350	2 951	301	2 328	7 269
1994	1 949	143	0	2 799	5 876	700	53	1 304	3 250	2 649	196	4 103	9 126
1995	2 211	828	1	1 910	5 939	496	222	872	2 542	2 707	1 051	2 782	8 481
1996	2 987	1 675	15	1 932	7 728	583	459	732	2 668	3 570	2 149	2 664	10 396
1997	4 210	2 045	8	2 704	10 275	837	645	614	2 937	5 047	2 698	3 318	13 212
1998	1 277	270	6	3 083	5 166	386	500	1 430	3 007	1 663	776	4 513	8 173
1999	1 311	502	0	4 679	6 988	285	351	1 620	2 905	1 596	853	6 299	9 893
2000	2 052	890	2	5473	8 955	466	576	2 033	3 690	2 518	1 468	7 506	12 645
2001	1 703	818	4	7 089	10 127	418	1 115	2 727	4 927	2 121	1 937	9 816	15 054
2002	1 317	1 056	8	5 921	8 586	345	1 222	2 246	4 231	1 662	2 286	8 167	12 817
2003	1 922	1 000	0	9 705	12 982	441	1 610	2 877	5 328	2 363	2 610	12 582	18 310
2004	1 516	859	0	10 768	13 502	486	1 739	3 179	5 742	2 002	2 598	13 947	19 244
2005	1 748	1 158	2	11 157	14 559	554	1 496	3 454	5 825	2 302	2 656	14 611	20 384
2006	1 583	1 147	0	9 883	12 975	601	2 195	3 258	6 323	2 184	3 342	13 141	19 298
2007	1 376	1 376	0	8 174	11 314	393	2 919	1 738	5 388	1 769	4 295	9 912	16 702
2008	1 420	1 205	4	6 838	9 945	300	3 428	1 099	5 076	1 720	4 637	7 937	15 021
2009	785	941	0	3 000	5 050	126	1 270	398	1 930	911	2 211	3 398	6 980
2010	1 979	1 336	0	3 408	7 103	280	1 331	391	2 130	2 259	2 697	3 799	9 233
2011	2 748	1 748	0	1 857	6 820	367	2 372	228	3 074	3 115	4 121	2 085	9 894
2012	2 534	1 787	0	841	5 860	283	2 050	142	2 562	2 817	3 837	983	8 422

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Table D.1 (*continued*)

Year	Development					Exploratory				Total			
	Successful oil	Crude bitumen		Gas	Total[a]	Successful oil	Crude bitumen[b]	Gas	Total[a]	Successful oil	Crude bitumen	Gas	Total[a]
		Commercial	Experimental										
2013	2 301	1 813	0	969	5 690	192	1 884	140	2 281	2 493	3 697	1 109	7 971
2014[c]	2 528	2 033	0	1 565	6 964	280	1 689	295	2 265	2 808	3 722	1 860	9 229
Total	**78 809**	**27 451**	**615**	**139 681**	**273 873**	**18 066**	**30 708**	**48 574**	**153 682**	**96 875**	**58 775**	**188 255**	**427 555**

Source: pre-1972—AER corporate database; 1972–1999—*Alberta Oil and Gas Industry Annual Statistics (ST17)*; 2000–2014—*Alberta Drilling Activity Monthly Statistics (ST59)*.

[a] Also includes unsuccessful, service, and suspended wells.

[b] Includes oil sands evaluation wells and exploratory wells licensed to obtain crude bitumen production.

[c] Starting in 2014, the data methodology used to compile drilling statistics was changed. As a result, *ST59: Alberta Drilling Activity—Monthly Statistics*, was revised, both in terms of content and format. The data reported in ST59 is from well licence applications submitted to the AER in Schedule 4 of *Directive 056: Energy Development Applications and Schedules*. Beginning with the March 2014 editions (January 2014 data), the AER began including data on wells that were drilled but did not report production. The historical dataset used in ST98 has not been revised.

* Included in oil.

** Not available.

Table D.2 Development and exploratory wells, pre-1972–2014; kilometres drilled annually

Year	Development					Exploratory				Total			
	Successful oil	Crude bitumen		Gas	Total[a]	Successful oil	Crude bitumen[b]	Gas	Total[a]	Successful oil	Crude bitumen	Gas	Total[a]
		Commercial	Experimental										
Pre-1972	18 843	*	**	11 640	36 991	2 611	**	4 059	26 556	21 459	**	15 699	63 547
1972	608	*	**	461	1 503	99	**	350	1 569	707	**	811	3 072
1973	659	*	**	635	2 053	127	**	465	1 802	786	**	1 100	3 855
1974	708	*	**	816	2 076	115	**	465	1 580	823	**	1 281	3 656
1975	686	*	**	1 020	2 192	107	**	494	1 457	793	**	1 514	3 649
1976	564	*	**	1 468	2 910	147	**	897	1 965	711	**	2 365	4 875
1977	668	*	**	1 299	2 926	188	**	1 029	2 324	856	**	2 328	5 250
1978	934	*	**	1 463	3 298	333	**	1 267	2 828	1 267	**	2 730	6 126
1979	1 387	*	**	1 713	3 840	507	**	1 411	3 073	1 894	**	3 124	6 913

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Table D.2 (*continued*)

	Development					Exploratory				Total			
		Crude bitumen											
Year	Successful oil	Commercial	Experimental	Gas	Total[a]	Successful oil	Crude bitumen[b]	Gas	Total[a]	Successful oil	Crude bitumen	Gas	Total[a]
1980	1 666	*	**	2 134	4 716	614	**	1 828	3 703	2 280	**	3 962	8 419
1981	1 270	*	**	1 601	3 598	573	**	1 442	3 172	1 843	**	3 043	6 770
1982	1 570	*	**	1 280	3 601	670	**	747	2 305	2 240	**	2 027	5 906
1983	2 249	*	**	758	3 834	610	**	407	1 819	2 859	**	1 165	5 653
1984	2 768	*	**	776	4 823	774	**	464	2 407	3 542	**	1 240	7 230
1985	3 030	577	123	1 389	6 373	1 048	99	465	2 962	4 078	799	1 854	9 335
1986	2 000	116	37	742	3 809	622	41	398	2 037	2 622	194	1 140	5 846
1987	2 302	209	68	730	4 250	793	16	518	2 486	3 095	293	1 248	6 736
1988	2 318	376	31	1 049	5 018	695	65	739	2 870	3 013	472	1 788	7 888
1989	1 130	24	13	733	2 622	382	33	747	2 353	1 512	70	1 480	4 975
1990	1 099	46	22	886	2 834	479	18	860	2 339	1 578	86	1 746	5 173
1991	1 307	62	6	641	2 720	346	14	615	1 979	1 653	82	1 256	4 699
1992	1 786	65	2	399	2 965	470	4	409	1 650	2 256	71	808	4 615
1993	3 044	193	7	1 616	5 850	695	2	773	2 585	3 739	202	2 389	8 435
1994	2 696	96	0	2 876	6 958	922	11	1 389	3 702	3 618	107	4 265	10 660
1995	2 856	620	1	1 969	6 702	624	52	995	2 791	3 480	673	2 964	9 493
1996	3 781	1 202	13	2 030	8 372	724	148	814	2 733	4 505	1 363	2 844	11 105
1997	5 380	1 561	8	2 902	11 383	1 080	142	733	2 928	6 460	1 711	3 635	14 311
1998	1 839	445	8	3 339	6 398	537	119	1 780	3 216	2 376	572	5 119	9 614
1999	1 566	401	0	4 319	6 838	390	60	1 620	3 041	1 956	461	5 939	9 879
2000	2 820	940	2	5 169	9 638	582	131	2 486	3 931	3 402	1 073	7 655	13 569
2001	2 454	834	25	6 846	10 840	603	253	3 219	4 857	3 057	1 112	10 065	15 697
2002	1 852	1 043	2	5 983	9 272	462	315	2 541	3 813	2 314	1 360	8 524	13 085

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Table D.2 (*continued*)

	Development					Exploratory				Total			
		Crude bitumen											
Year	Successful oil	Commercial	Experimental	Gas	Total[a]	Successful oil	Crude bitumen[b]	Gas	Total[a]	Successful oil	Crude bitumen	Gas	Total[a]
2003	2 727	1 032	0	9 610	13 825	573	388	3 347	4 799	3 300	1 420	12 957	18 624
2004	2 095	1 000	0	10 767	14 284	663	354	3 905	5 297	2 758	1 354	14 672	19 581
2005	2 534	1 353	3	11 519	16 009	792	338	4 616	6 117	3 326	1 694	16 135	22 126
2006	2 263	1 305	0	10 549	14 549	903	496	4 720	6 477	3 166	1 801	15 269	21 026
2007	2 045	1 550	0	8 447	12 469	623	751	2 731	4 582	2 668	2 301	11 178	17 051
2008	2 159	1 379	2	7 790	11 758	447	929	1 726	3 478	2 606	2 310	9 516	15 236
2009	1 257	1 033	0	3 852	6 468	194	380	804	1 619	1 451	1 413	4 656	8 087
2010	3 809	1 336	0	5 134	10 653	514	461	848	1 965	4 323	1 797	5 982	12 618
2011	6 106	1 720	0	4 071	12 425	676	870	594	2 373	6 782	2 590	4 665	14 798
2012	6 218	2 179	0	2 536	11 630	591	782	435	2 018	6 809	2 961	2 971	13 648
2013	5 916	2 127	0	2 981	11 822	382	656	515	1 704	6 298	2 783	3 496	13 526
2014[c]	6 744	2 619	0	5 365	15 669	642	569	1 253	2 464	7 386	3 188	6 618	18 133
Total	**121 713**	**27 443**	**373**	**153 303**	**342 764**	**25 929**	**8 497**	**61 920**	**151 726**	**147 647**	**36 313**	**215 223**	**494 490**

Source: pre-1972—AER corporate database; 1972–1999—*Alberta Oil and Gas Industry Annual Statistics (ST17)*; 2000–2014—*Alberta Drilling Activity Monthly Statistics (ST59)*.

[a] Also includes unsuccessful, service, and suspended wells.

[b] Includes oil sands evaluation wells and exploratory wells licensed to obtain crude bitumen production.

[c] Starting in 2014, the data methodology used to compile drilling statistics was changed. As a result, *ST59: Alberta Drilling Activity—Monthly Statistics*, was revised, both in terms of content and format. The data reported in ST59 is from well licence applications submitted to the AER in Schedule 4 of *Directive 056: Energy Development Applications and Schedules*. Beginning with the March 2014 editions (January 2014 data), the AER began including data on wells that were drilled but did not report production. The historical dataset used in ST98 has not been revised.

* Included in oil.

** Not available.

Appendix E Crude Bitumen Pay Thickness and Geological Structure Contour Maps

This appendix contains geological maps from the Crude Bitumen section that have appeared in previous editions of *ST98*. These are the maps that the most recent determinations of in-place resources are based on. Any new mapping will be described in the main body of *ST98* in the first year of reporting.

Regional Map

Sub-Cretaceous Unconformity

The sub-Cretaceous unconformity is the stratigraphic surface that forms the base on which the bitumen-bearing Cretaceous sediments were deposited. **Figure AE.1** is a structure contour map of that surface as it would have appeared at the end of Bluesky/Wabiskaw time. The parts of the Nisku and Grosmont formations that are bitumen bearing are outlined on this map. These Devonian carbonate formations subcrop along the sub-Cretaceous surface and contain bitumen in an updip location along the subcrop edge. Of particular note are the areas on this map identified as having a relative subsea elevation of greater than zero. These areas were still emergent at the end of Bluesky/Wabiskaw time and would have existed as islands within the transgressing northern Boreal Sea.

Peace River Oil Sands Area

Peace River Bluesky-Gething Deposit

The Bluesky-Gething deposit was reassessed for year-end 2006. **Figure AE.2** is the bitumen pay thickness map for the Bluesky-Gething deposit based on cutoffs of 6 mass per cent and 1.5 metres (m) thickness. The Bluesky-Gething is mapped as a single bitumen zone so that the full extent of the deposit at 6 mass per cent can be shown. Also shown on **Figure AE.2** are the paleotopographic highlands as they would have existed at the time of the end of the deposition of the Bluesky Formation. These highlands, composed of carbonate rocks of Devonian and Mississippian age, controlled the deposition of the Bluesky and correspondingly the extent of the reservoir. Oil migrated updip became trapped beneath the overlying Wilrich shales and against the highlands, where it was eventually biodegraded into bitumen.

Athabasca Oil Sands Area

Athabasca Grosmont Deposit

In 2009, the AER updated the previous (1990) resource assessment of the Athabasca Grosmont deposit. Over 1330 wells were used within the study area, which extended from Townships 62 to 103 and Range 13, West of the 4th Meridian, to Range 6, West of the 5th Meridian. In its resource assessment, the AER included the bitumen from the Upper Ireton Formation. The Grosmont and the Ireton formations are considered to be in hydraulic communication.

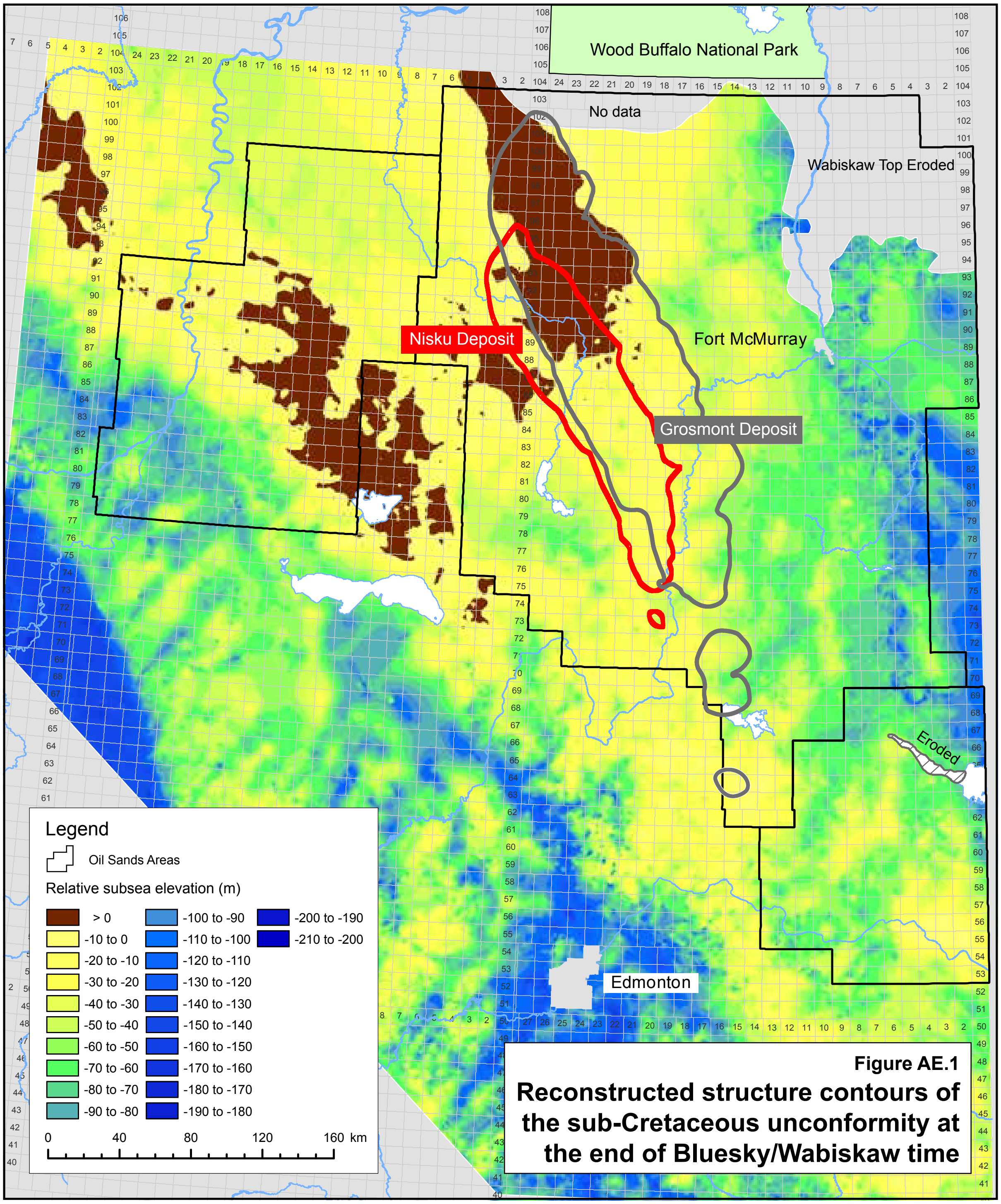


Figure AE.1
Reconstructed structure contours of the sub-Cretaceous unconformity at the end of Bluesky/Wabiskaw time

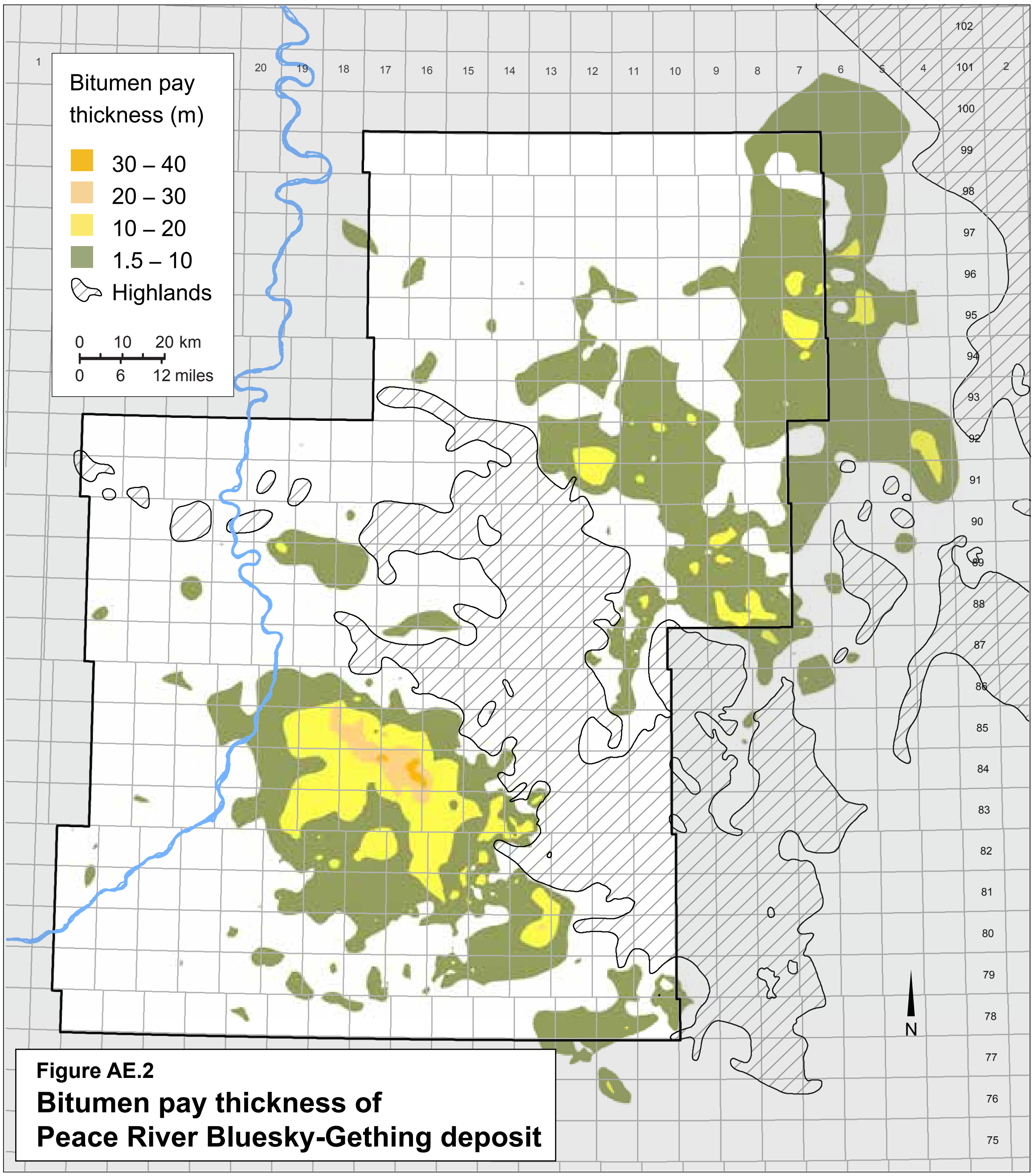


Figure AE.2
Bitumen pay thickness of Peace River Bluesky-Gething deposit

The Grosmont Formation is a late-Devonian shallow-marine to peritidal platform carbonate consisting of four recognizable units within the deposit: the Grosmont A, B, C, and D. All of the hydrocarbons are located in an updip position, structurally trapped along the erosional edge and contained by the overlying Clearwater Formation. **Figure AE.3** is the cumulative bitumen net pay isopachs for the entire Grosmont deposit.

Athabasca Wabiskaw-McMurray Deposit

In 2003, the AER completed a reassessment of the Wabiskaw-McMurray deposit using geological information from over 13 000 wells and bitumen content evaluations from over 9000 wells to augment the over 7000 boreholes already assessed within the surface mineable area (SMA; see below for details). In 2005 and 2007, nearly 700 and 2700 new wells respectively, mostly outside the SMA, were added to the reassessment, and the volumes and maps were revised. In 2008, about 2500 additional wells outside the SMA and about 18 000 wells inside the SMA were added. In 2009, about 1700 wells, including about 350 from within the SMA, were added.

Figure AE.4 is a bitumen pay thickness map of the Wabiskaw-McMurray deposit revised for year-end 2009 based on cutoffs of 6 mass per cent and 1.5 m thickness. In this map, the deposit is treated as a single bitumen zone and the pay is accumulated over the entire geological interval. Also shown is the extent of the SMA, an AER-defined area of 51½ townships north of Fort McMurray covering that part of the Wabiskaw-McMurray deposit where the total overburden thickness generally does not exceed 65 m. This designation is for resource administration purposes and carries no regulatory authority. That is to say that while mining activities are likely to be confined to the SMA, they may occur outside the area's boundaries, while in situ activities may occur within the SMA. Because the extent of the SMA is defined using township boundaries, it incorporates a few areas containing deeper bitumen resources that are more amenable to in situ recovery. The AER has generated a line that generally separates the mineable portion of the deposit from the in situ portion, and that line is shown in **Figure AE.4**.

Athabasca Upper, Middle, and Lower Grand Rapids Deposits

The 2011 year-end review for the three Athabasca Grand Rapids deposits (Upper, Middle, and Lower), **Figure AE.5, Figure AE.6**, and **Figure AE.7**, included an evaluation of 3575 wells for stratigraphic tops and 1887 for reservoir parameters. The study area covered Townships 73 to 87 within Range 17, West of the 4th Meridian, to Range 1, West of the 5th Meridian. The reassessment resulted in in-place bitumen resources being increased from 8678 10^6 m^3 to 9274 10^6 m^3 for the Grand Rapids deposits. This represents a 7 per cent increase, which is attributed to an increased number of wells drilled in the area.

The Grand Rapids Formation is interpreted as a series of prograding sequences of shoreface sands and shales. Informally the formation has been divided into Upper, Middle, and Lower sequences, with the boundaries defined by laterally extensive marine shales (maximum flooding surfaces). The Athabasca Upper Grand Rapids accounts for the majority (approximately 60 per cent) of the bitumen-bearing sand within this formation (**Table R3.3**). The Grand Rapids Formation is bounded above and below by the marine shales of the Joli Fou and Clearwater formations, respectively.

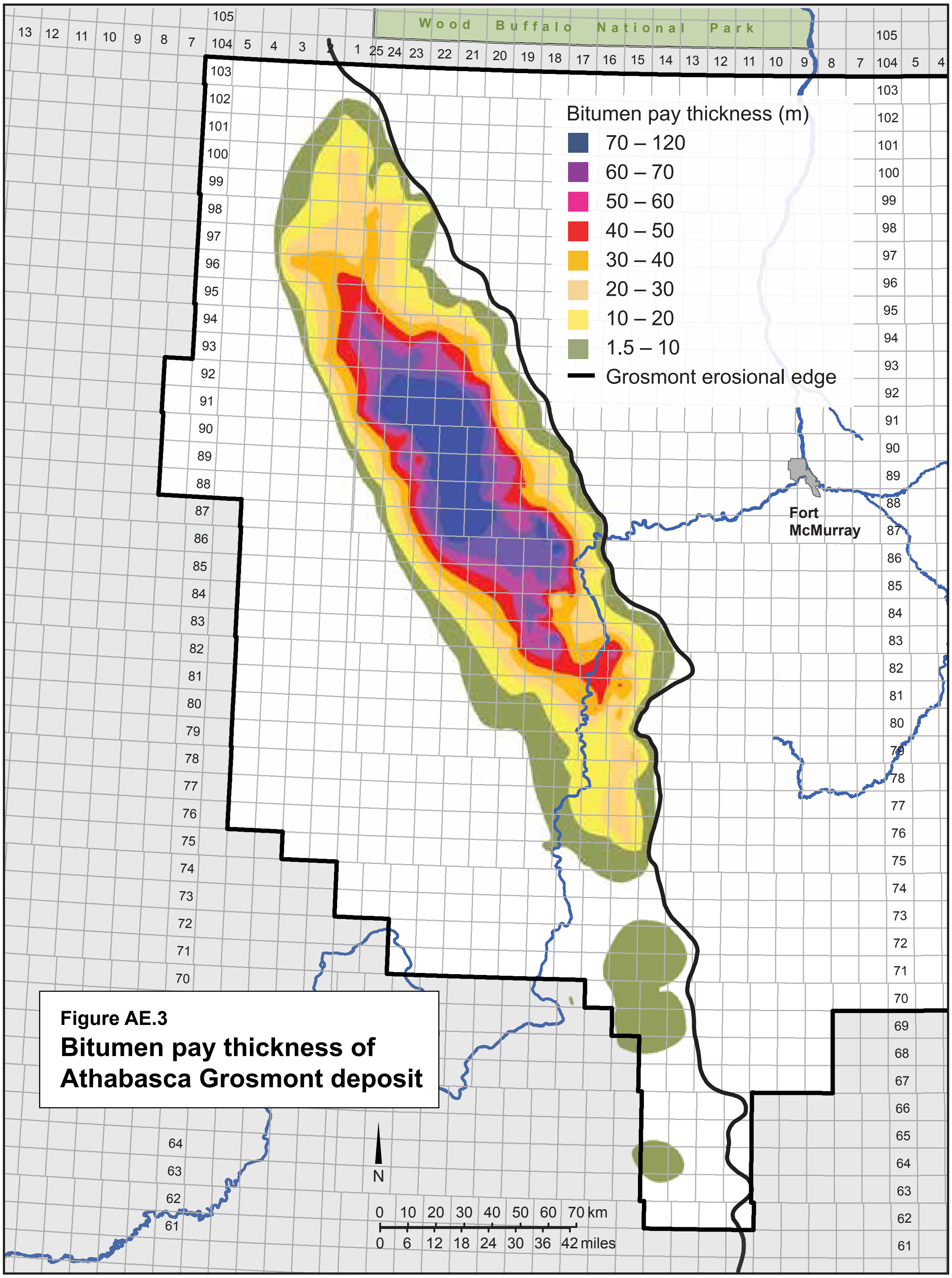


Figure AE.3
Bitumen pay thickness of Athabasca Grosmont deposit

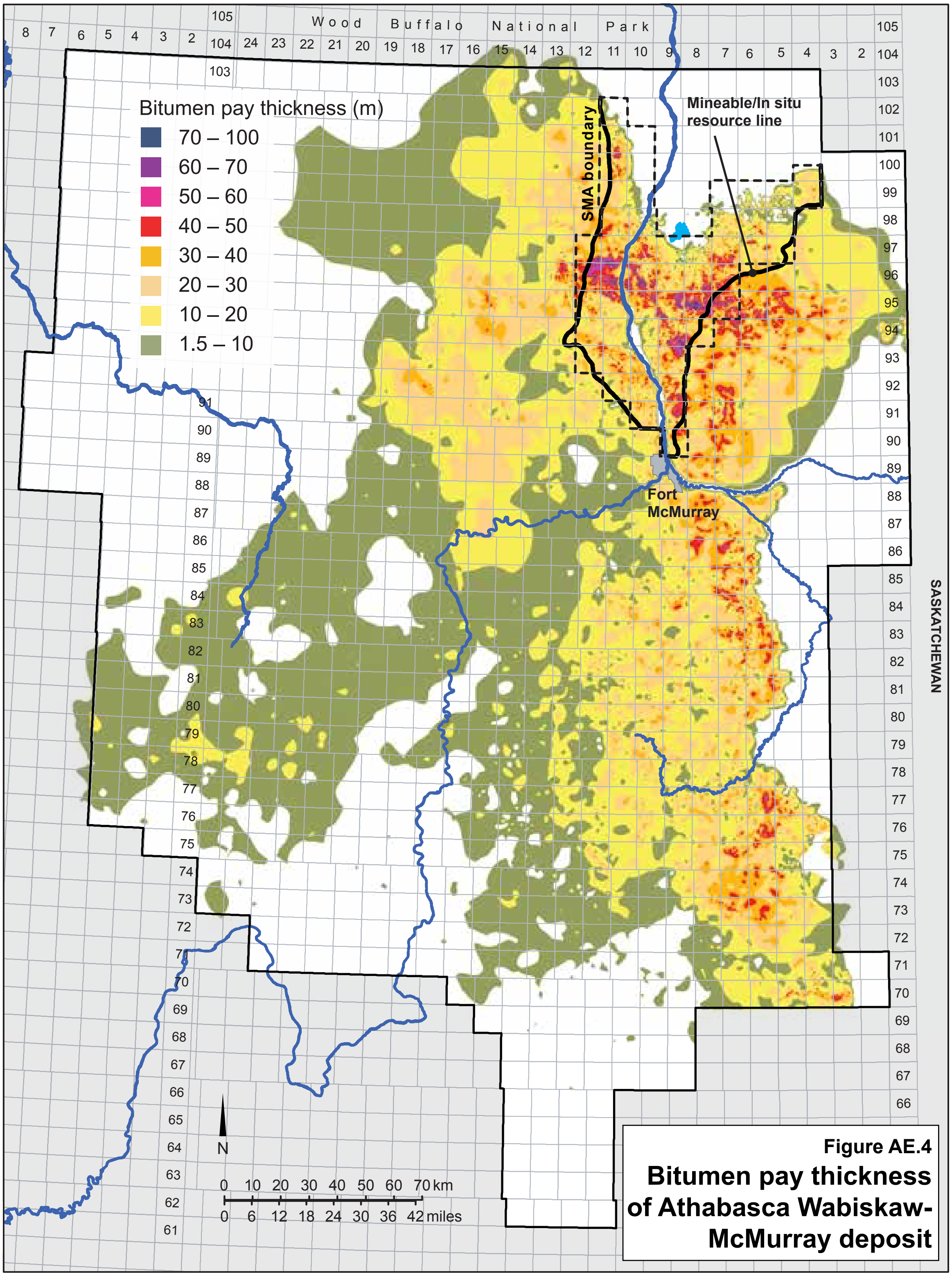


Figure AE.4
Bitumen pay thickness of Athabasca Wabiskaw-McMurray deposit

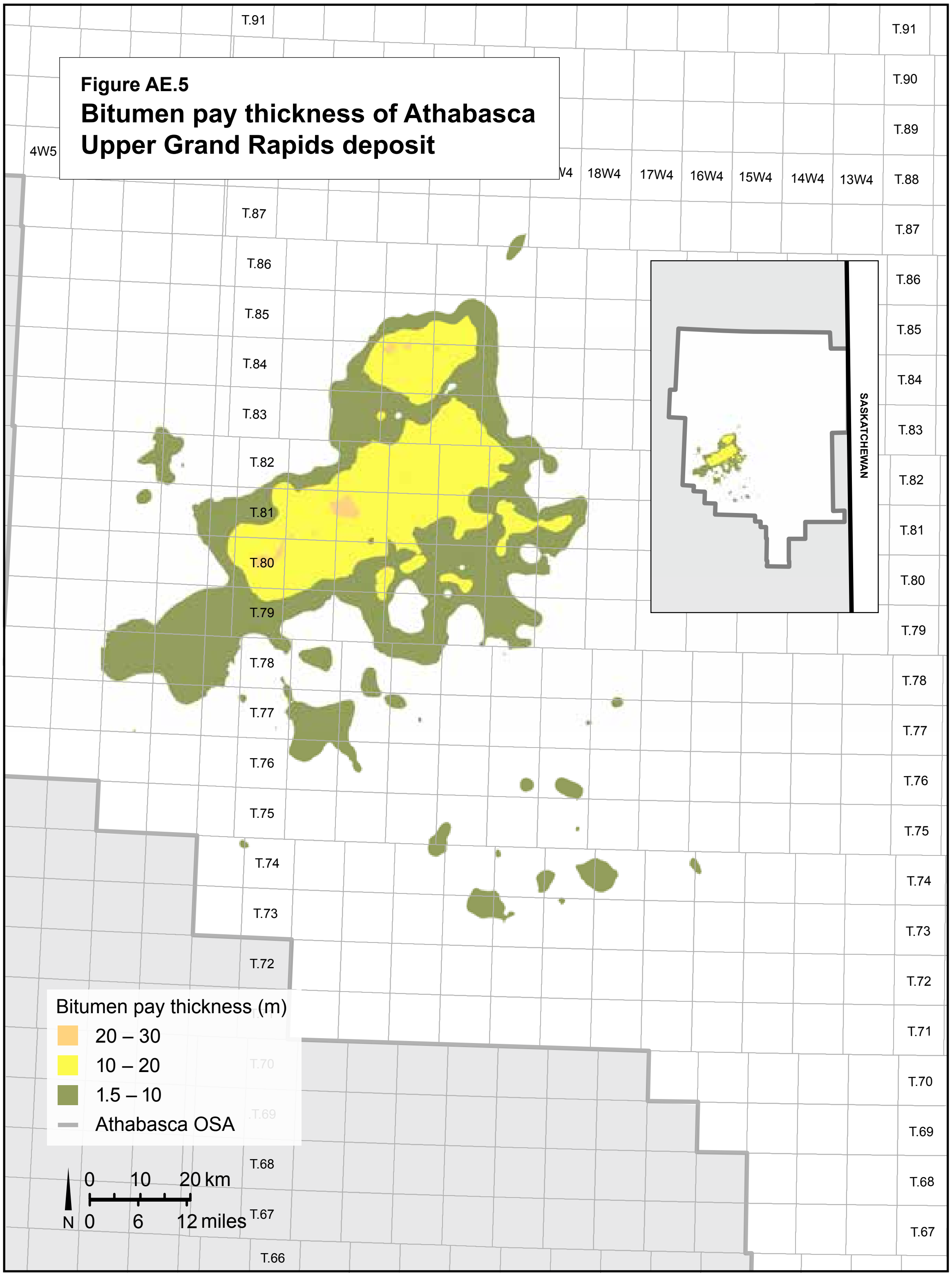
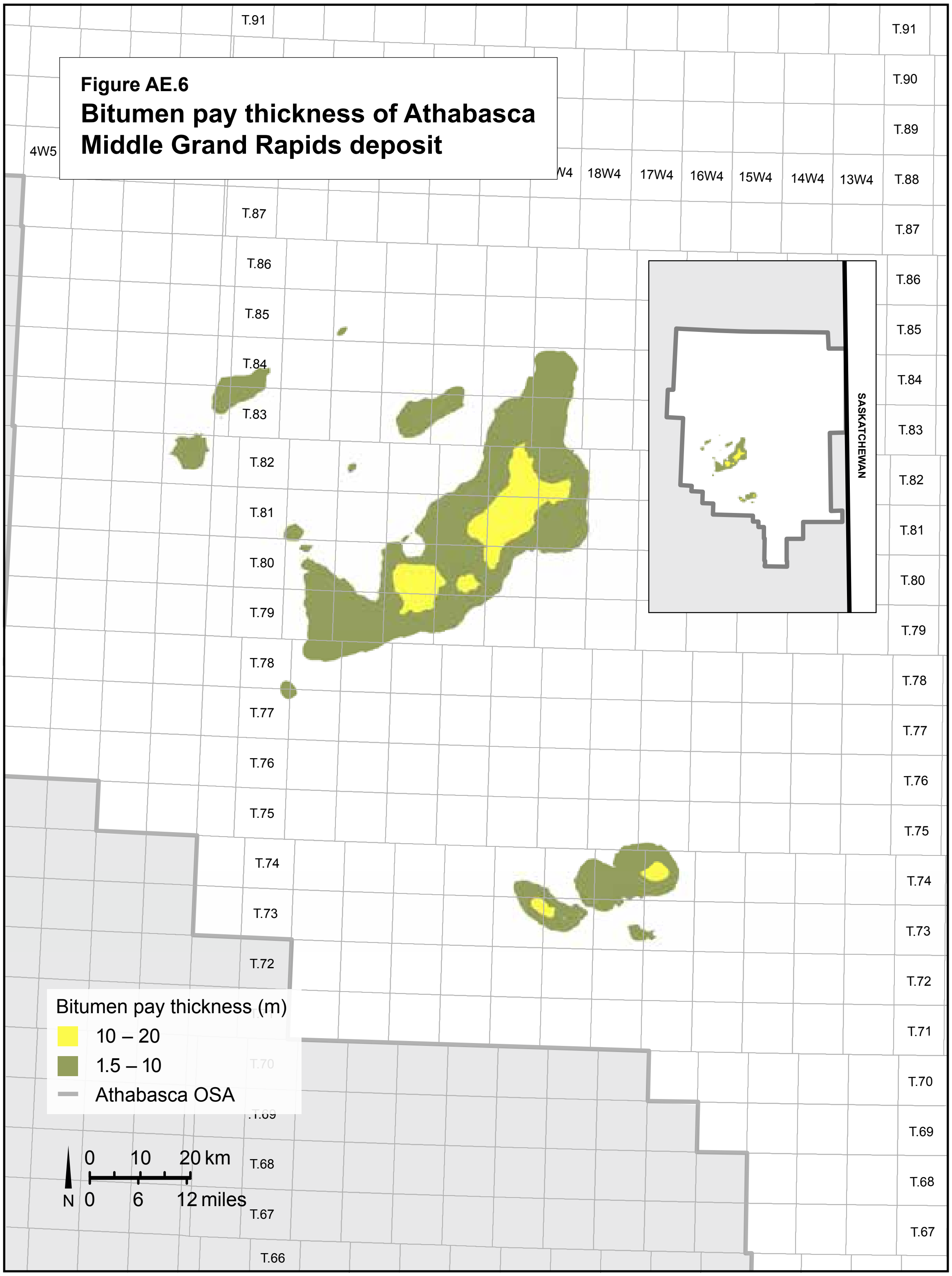


Figure AE.5
Bitumen pay thickness of Athabasca Upper Grand Rapids deposit
T.91
T.90
T.89
T.88
T.87
T.86
T.85
T.84
T.83
T.82
T.81
T.80
T.79
T.78
T.77
T.76
T.75
T.74
T.73
T.72
T.71
T.70
T.69
T.68
T.67
T.66
4W5
18W4
17W4
16W4
15W4
14W4
13W4
SASKATCHEWAN
Bitumen pay thickness (m)
20 – 30
10 – 20
1.5 – 10
Athabasca OSA
0 10 20 km
0 6 12 miles
N

Figure AE.6
Bitumen pay thickness of Athabasca Middle Grand Rapids deposit



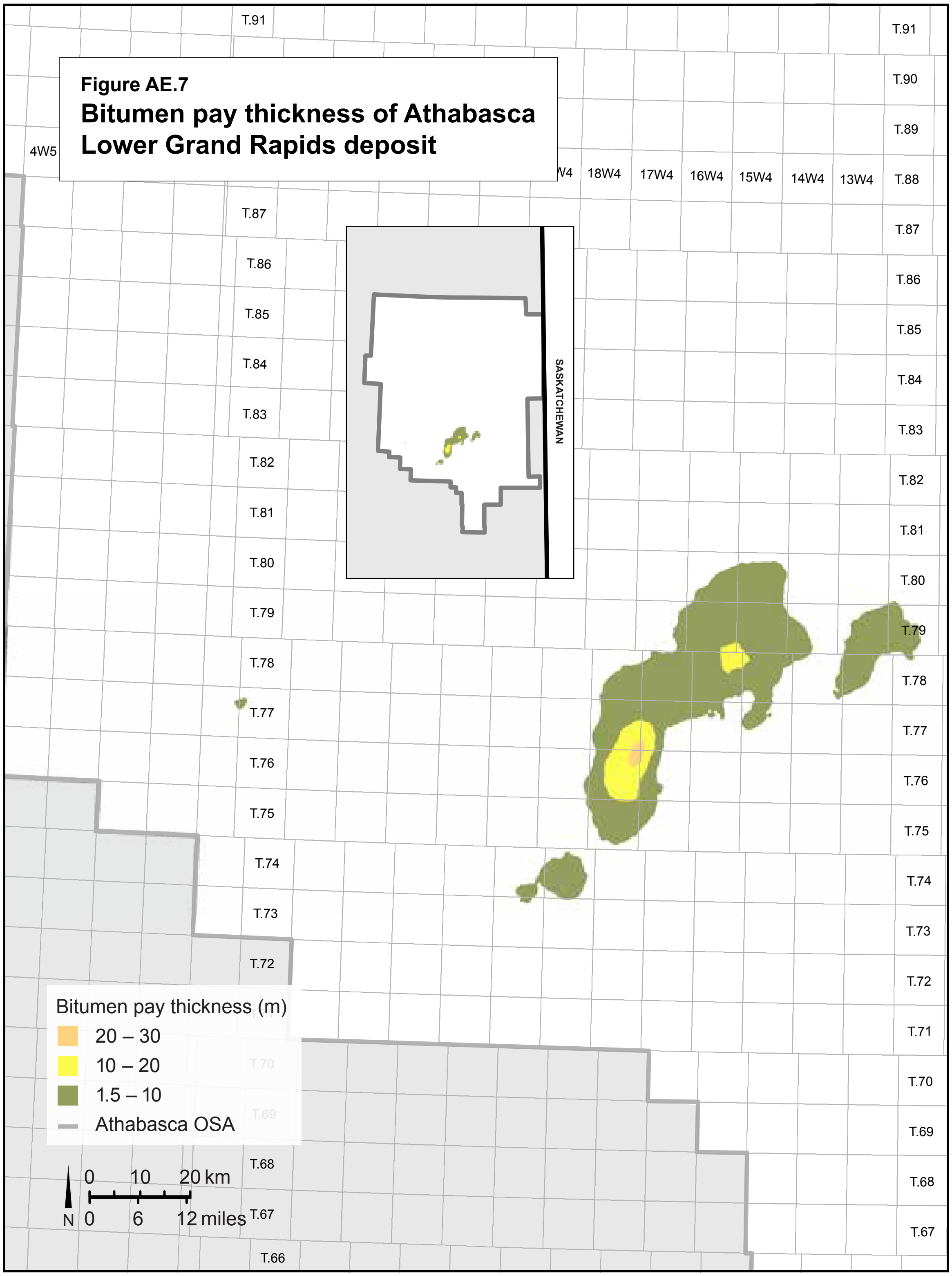


Figure AE.7
Bitumen pay thickness of Athabasca Lower Grand Rapids deposit
Bitumen pay thickness (m)
20 – 30
10 – 20
1.5 – 10
Athabasca OSA
0 10 20 km
0 6 12 miles
N
SASKATCHEWAN
4W5
18W4
17W4
16W4
15W4
14W4
13W4
T.91
T.90
T.89
T.88
T.87
T.86
T.85
T.84
T.83
T.82
T.81
T.80
T.79
T.78
T.77
T.76
T.75
T.74
T.73
T.72
T.71
T.70
T.69
T.68
T.67
T.66

Athabasca Nisku Deposit

The 2011 year-end review of the Athabasca Nisku Formation, **Figure AE.8**, included an evaluation of 560 wells for stratigraphic tops and 130 wells for reservoir parameters. The AER, in its evaluation of the Nisku Formation, included bitumen from the Blueridge Formation. The Calmar Formation is a shale within this deposit. Information to date indicates that the Calmar Formation is a potential baffle. The study area covered Townships 75 to 96 within Range 18, West of the 4th Meridian, to Range 4, West of the 5th Meridian. The reassessment resulted in in-place bitumen resources being increased from 10 330 10^6 m^3 to 16 232 10^6 m^3. This represents a 57 per cent increase, which is attributed to an increase in well data and the expansion of the delineated resource area.

The Nisku Formation is a late-Devonian shelf carbonate. Early dolomitization and subsequent leaching of meteoric waters led to karsting and the creation of vugs and caves. The Nisku is a naturally fractured reservoir. Similar to the Grosmont Formation, the bitumen in the Nisku is contained in a triple porosity system within the vugs, the fractures, and the rock matrix. Hydrocarbons were probably trapped structurally along the updip erosional edge before degradation to bitumen.

Cold Lake Oil Sands Area

Sub-Cretaceous Unconformity

Figure AE.9 is a map of the reconstructed structure contours for the sub-Cretaceous unconformity in the northern part of the Cold Lake Oil Sands Area as they would have been at the beginning of deposition of the Mannville Clearwater Formation.

Cold Lake Wabiskaw-McMurray Deposit

For year-end 2005, the AER reassessed the northern portion of the Cold Lake Wabiskaw-McMurray deposit. Stratigraphic information and detailed petrophysical evaluations from almost 400 wells were used in this reassessment. **Figure AE.10** is the bitumen pay thickness map for the Cold Lake Wabiskaw-McMurray deposit based on cutoffs of 6 mass per cent and 1.5 m thickness. Although the Wabiskaw-McMurray contains some regionally mappable internal seals, and therefore several bitumen zones, this map was produced as a single bitumen zone to provide a regional overview of the distribution of the bitumen-saturated sands. A cutoff of 6 mass per cent bitumen was used.

Cold Lake Clearwater Deposit

For year-end 2005, the AER completed a reassessment of the Clearwater deposit. **Figure AE.11** is a bitumen pay thickness map for the Clearwater deposit based on cutoffs of 6 mass per cent and 1.5 m thickness. As the Clearwater does not contain regionally mappable internal shales or mudstones that can act as seals, the deposit is mapped as a single bitumen zone.

Cold Lake Upper and Lower Grand Rapids Deposits

A reassessment for year-end 2009 of the Upper and Lower Grand Rapids deposits included a review of some 12 000 wells for stratigraphic tops and net pay. The study area from Townships 52 to 66 replaced the area used in the previous assessment. Stratigraphy and net pay determination were completed for each Grand Rapids zone: Colony, McLaren, Waseca, Sparky, General Petroleum (GP), Rex, and Lloydminster.

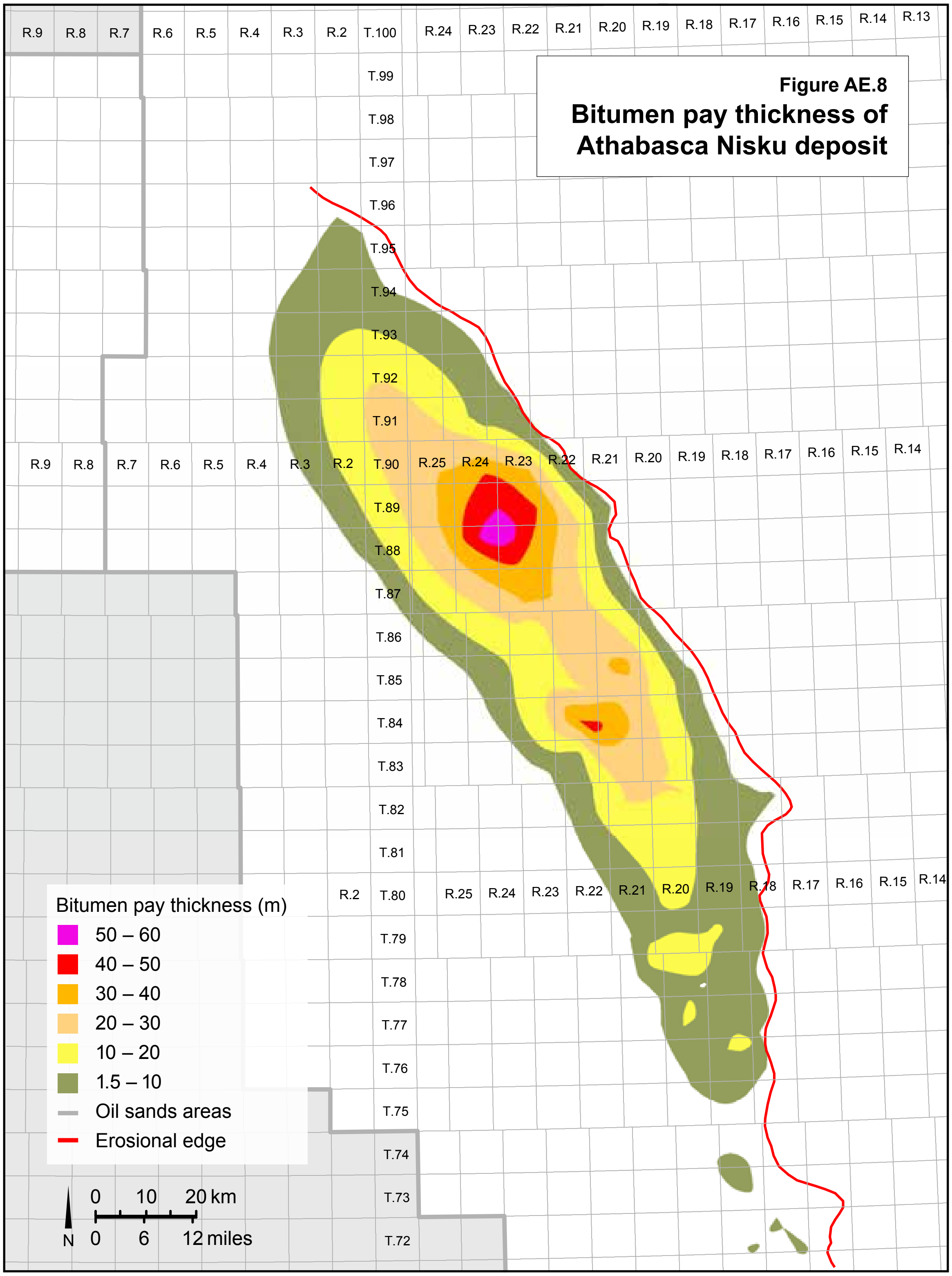
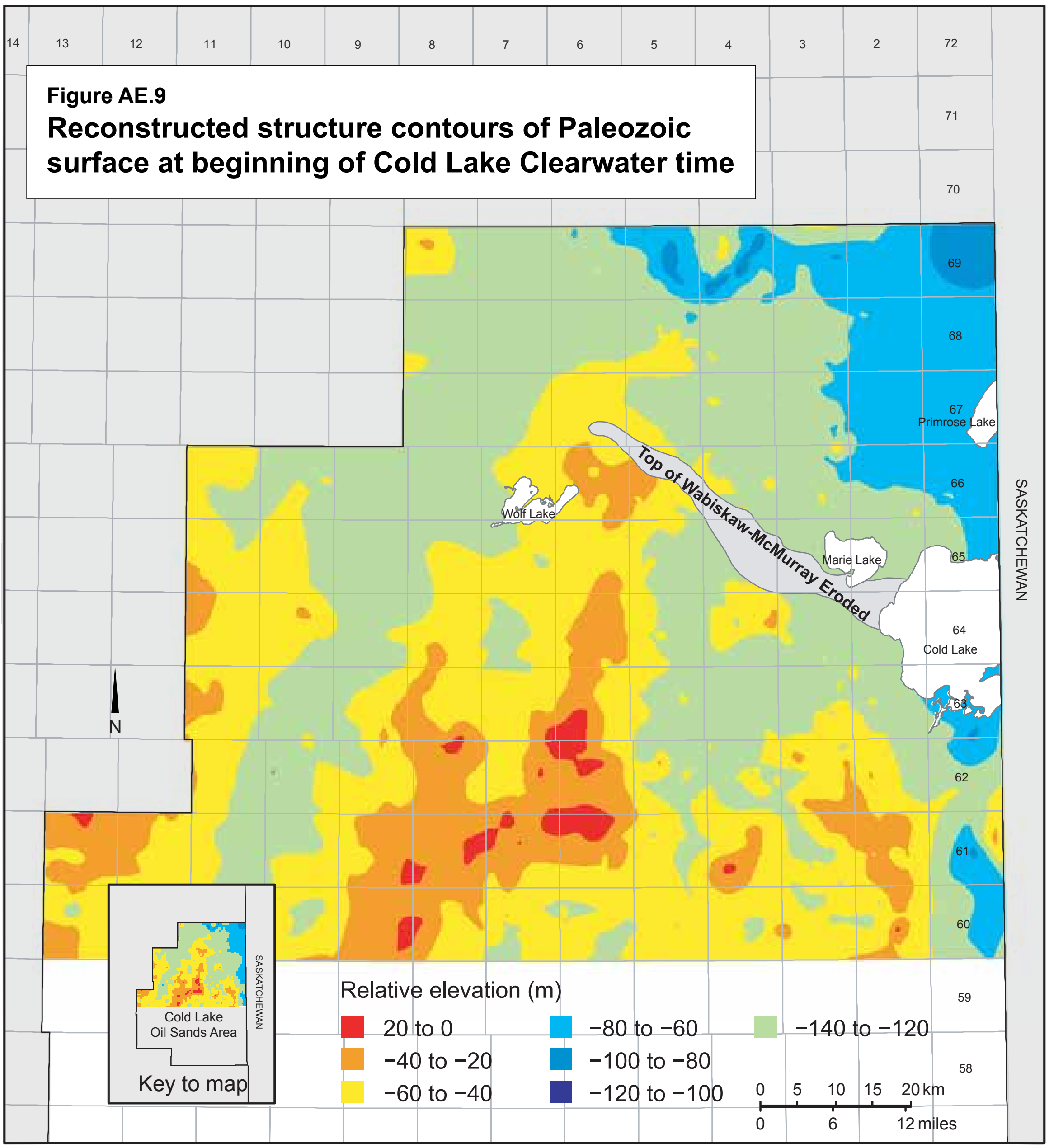


Figure AE.8
Bitumen pay thickness of Athabasca Nisku deposit
R.9
R.8
R.7
R.6
R.5
R.4
R.3
R.2
T.100
R.24
R.23
R.22
R.21
R.20
R.19
R.18
R.17
R.16
R.15
R.14
R.13
T.99
T.98
T.97
T.96
T.95
T.94
T.93
T.92
T.91
T.90
R.25
T.89
T.88
T.87
T.86
T.85
T.84
T.83
T.82
T.81
T.80
T.79
T.78
T.77
T.76
T.75
T.74
T.73
T.72
Bitumen pay thickness (m)
50 – 60
40 – 50
30 – 40
20 – 30
10 – 20
1.5 – 10
Oil sands areas
Erosional edge
0 10 20 km
0 6 12 miles
N

Although crude bitumen within both Grand Rapids deposits is pervasive throughout much of the Cold Lake Oil Sands Area, the developable resource (primary bitumen for the most part) is generally associated with Paleozoic highs. **Figure AE.12** and **Figure AE.13** are maps of the cumulative net pay isopachs for the Upper Grand Rapids deposit and the Lower Grand Rapids deposit respectively. The net pay interpretations and volumetric calculations were completed for each zone and were then summed for the relevant deposit. The Colony, Waseca, and McLaren are included in the Upper Grand Rapids, and the Sparky, GP, Rex, and Lloydminster are included in the Lower Grand Rapids.

Figure AE.9
Reconstructed structure contours of Paleozoic surface at beginning of Cold Lake Clearwater time



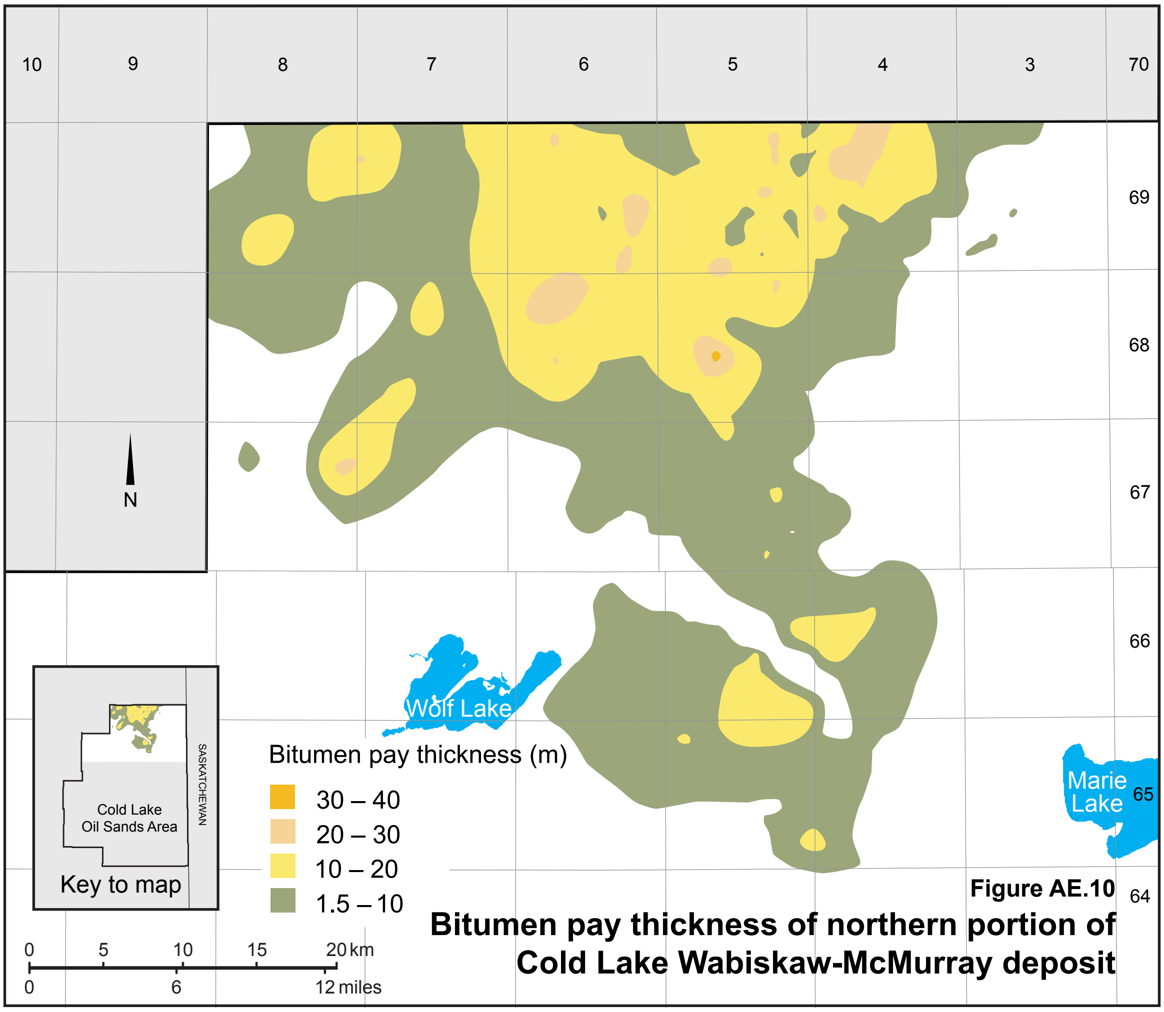


Figure AE.10
Bitumen pay thickness of northern portion of Cold Lake Wabiskaw-McMurray deposit

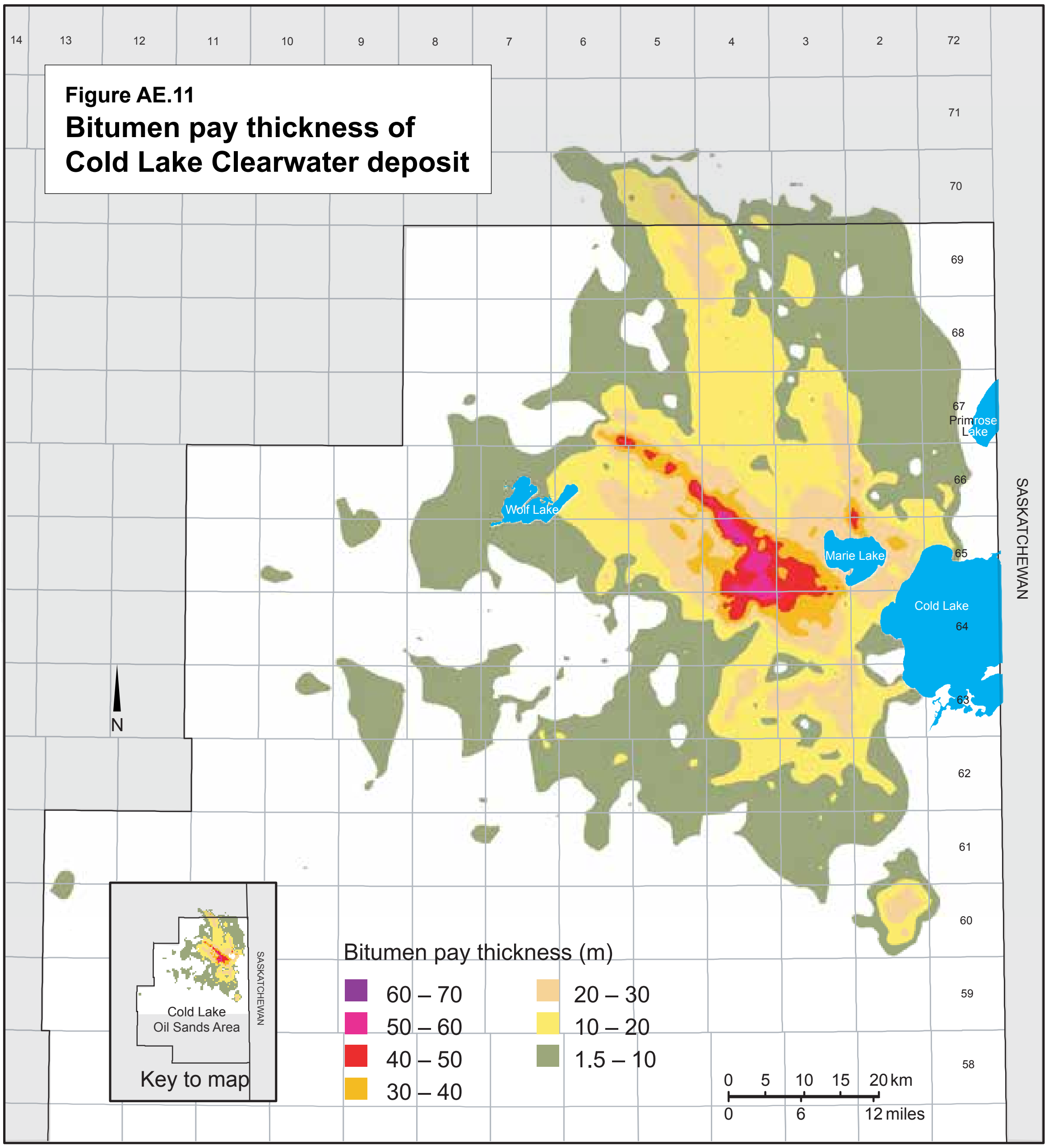


Figure AE.11
Bitumen pay thickness of Cold Lake Clearwater deposit

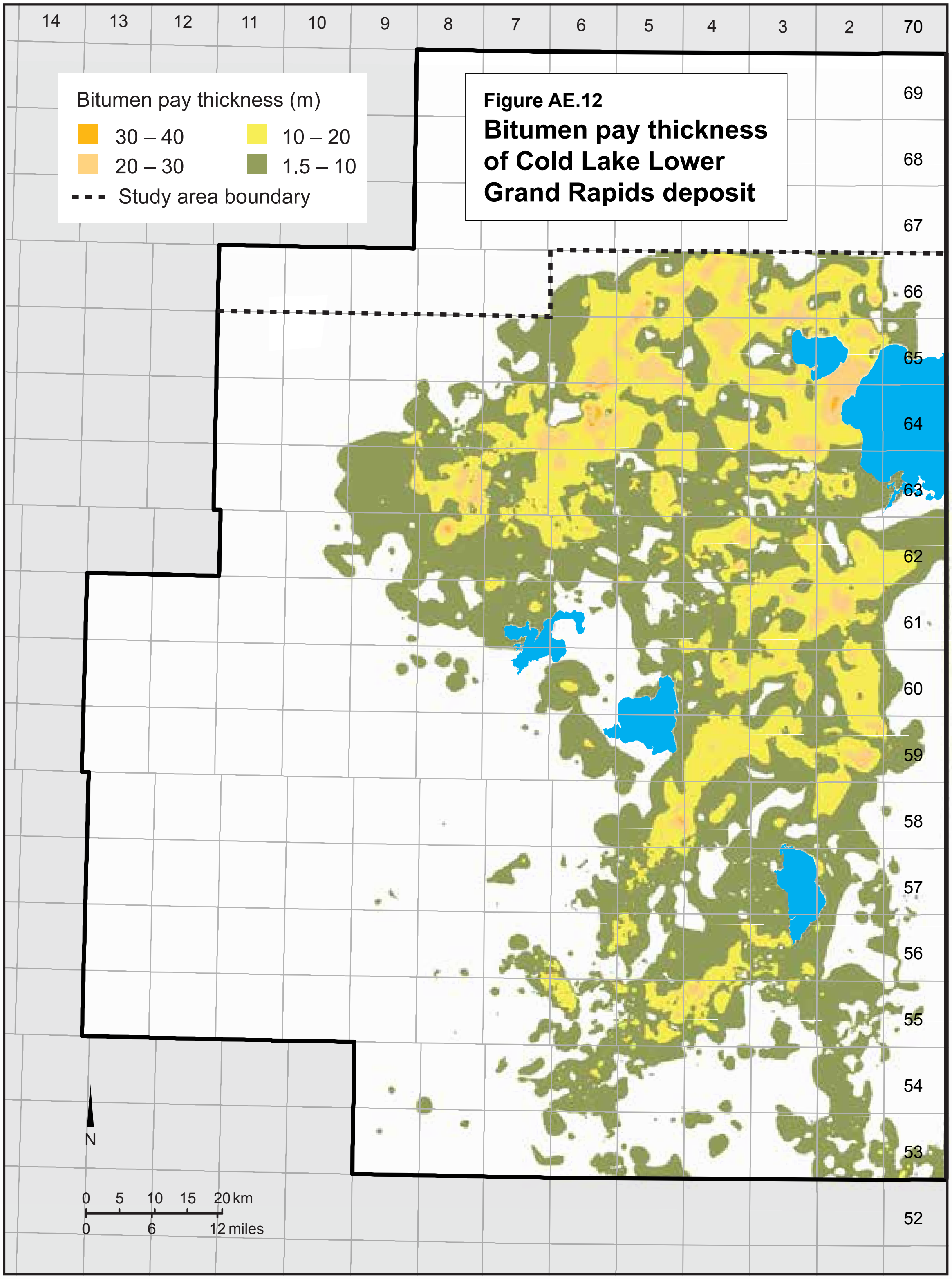


Figure AE.12
Bitumen pay thickness of Cold Lake Lower Grand Rapids deposit

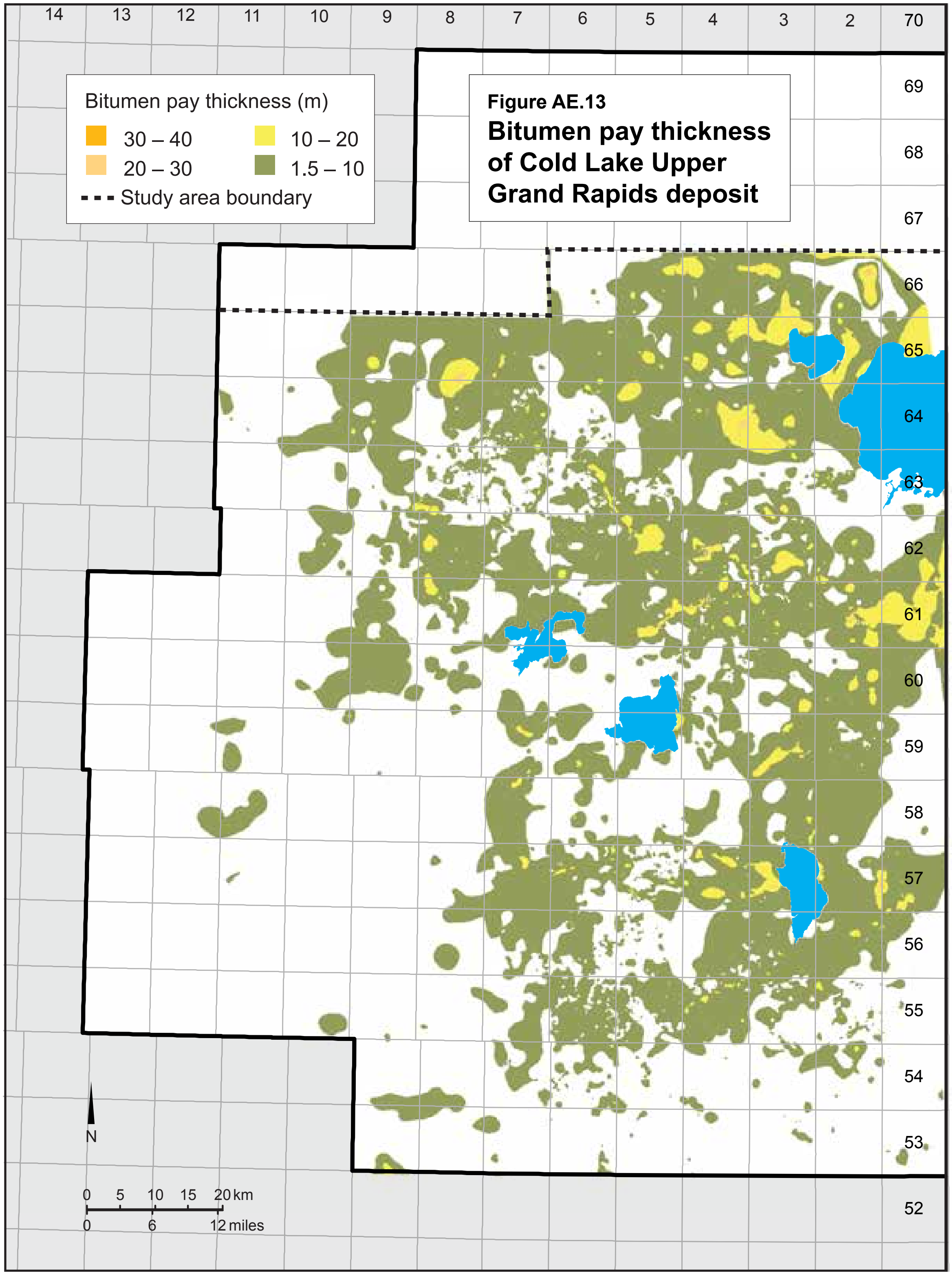


Figure AE.13
Bitumen pay thickness of Cold Lake Upper Grand Rapids deposit

Appendix F Summary of Alberta's Shale- and Siltstone-Hosted Hydrocarbon Resource Potential

In 2012, the AER completed a study entitled *ERCB/AGS Open File Report 2012-06: Summary of Alberta's Shale- and Siltstone-Hosted Hydrocarbon Resource Potential*. The results of that study have been incorporated into this report, and the figures showing the medium (P_{50}) in-place resource values of natural gas, natural gas liquids, and crude oil for each of the six formations detailed in that study are shown in the six figures in this appendix.

Figure AF.1

P50 gas, oil, and liquids initial in-place for the Duvernay Formation

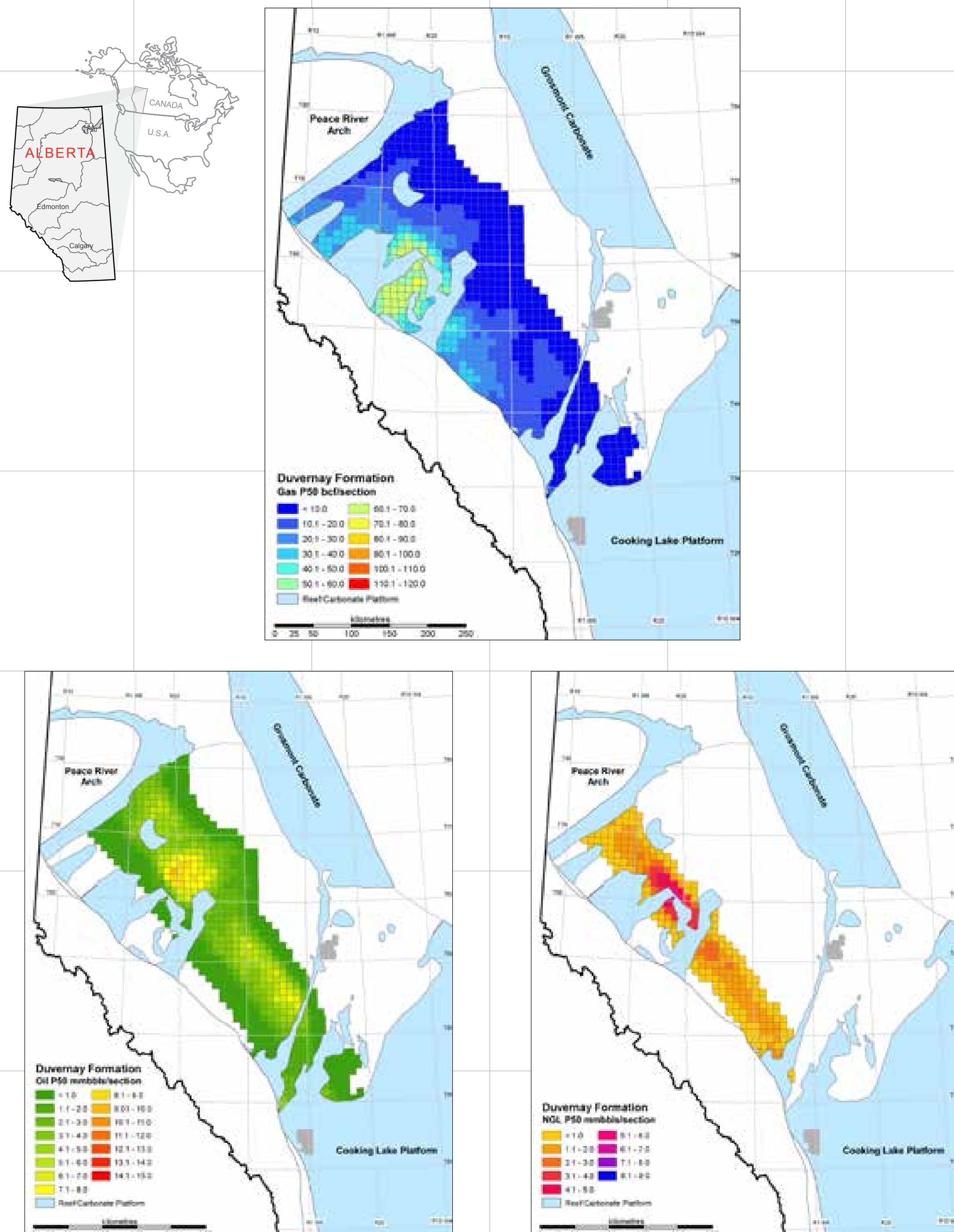


Figure AF.2

P50 gas, oil, and liquids initial in-place for the Muskwa Formation

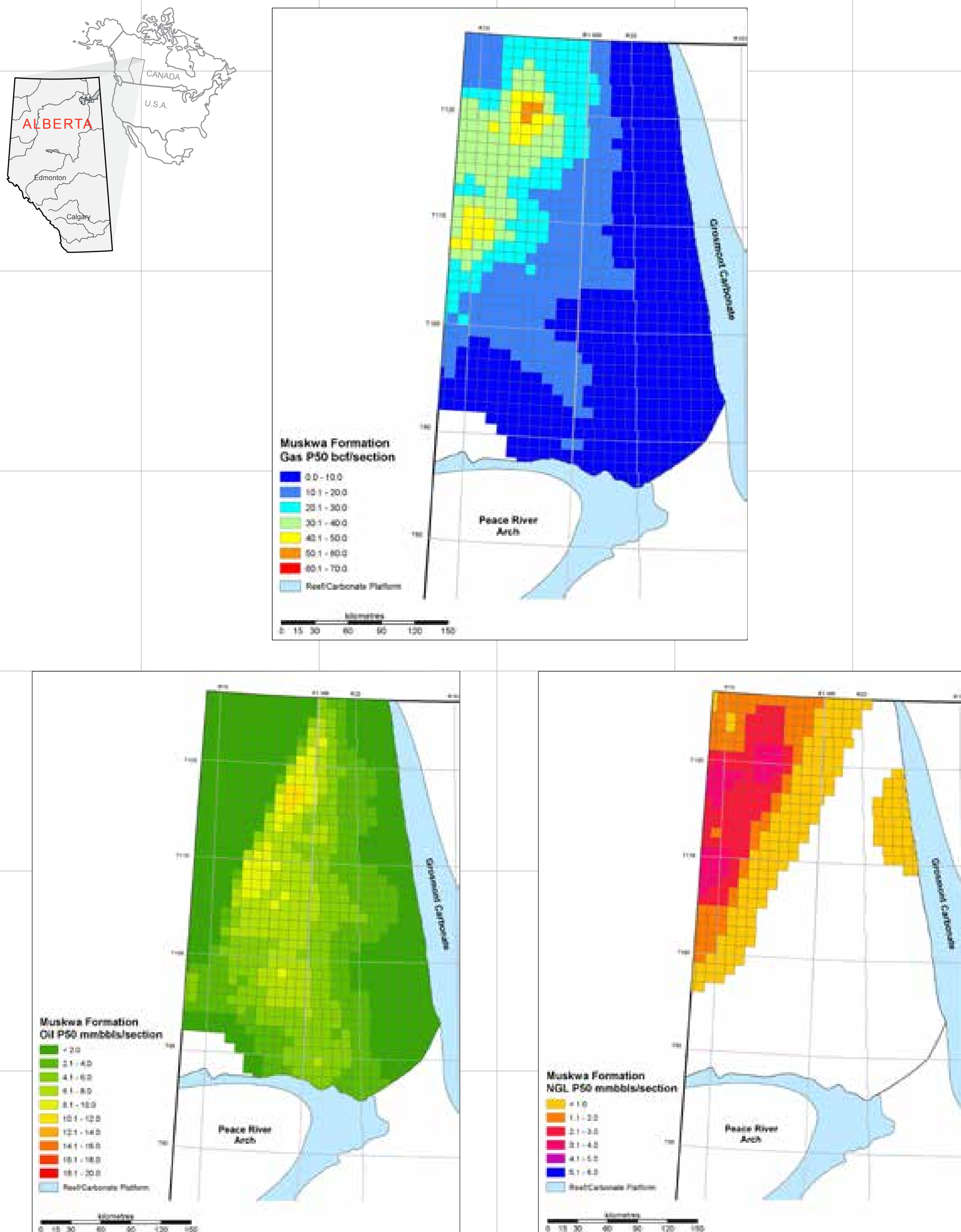


Figure AF.3

P50 gas, oil, and liquids initial in-place for the Montney Formation

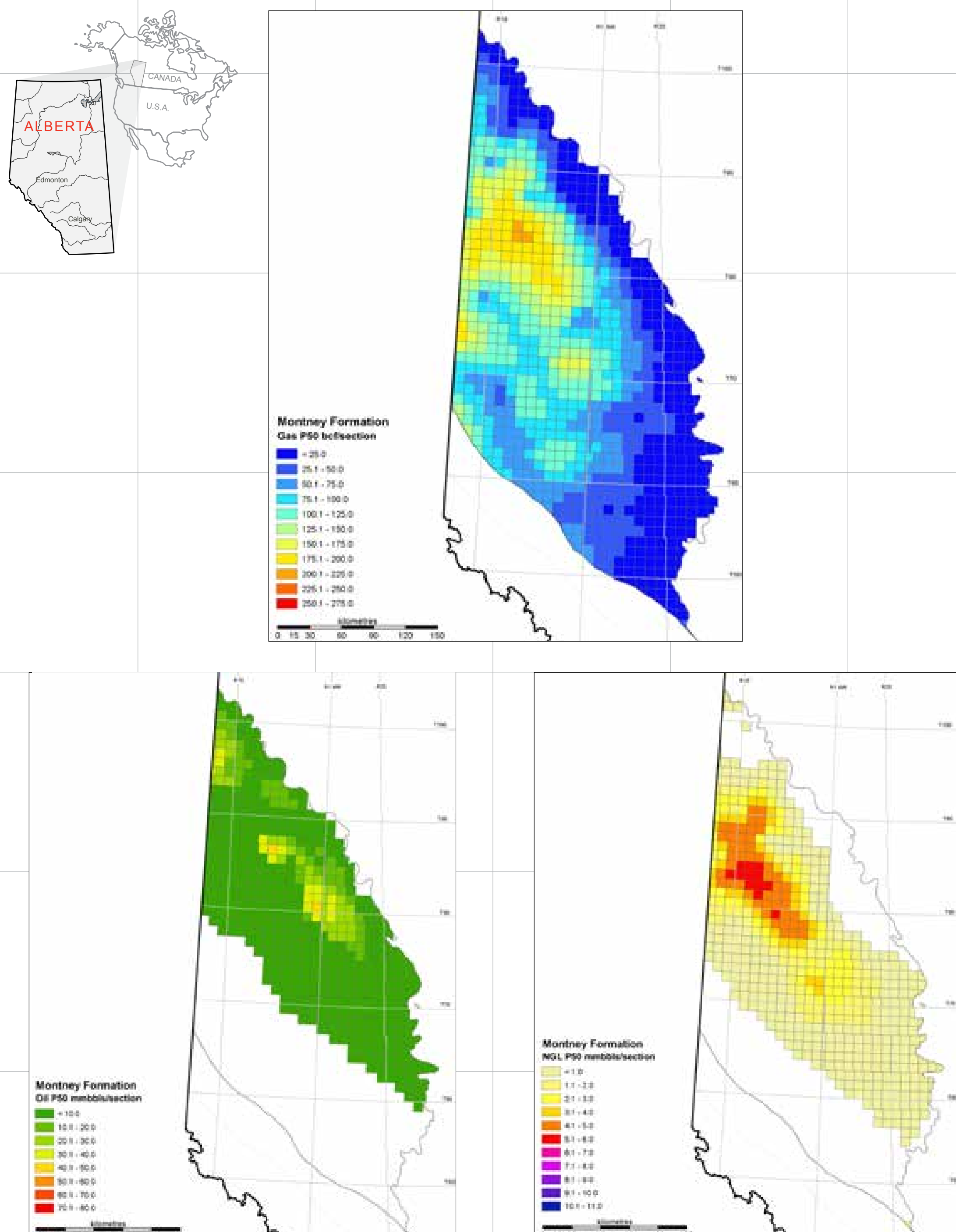


Figure AF.4

P50 gas, oil, and liquids initial in-place for the Banff/Exshaw Formation

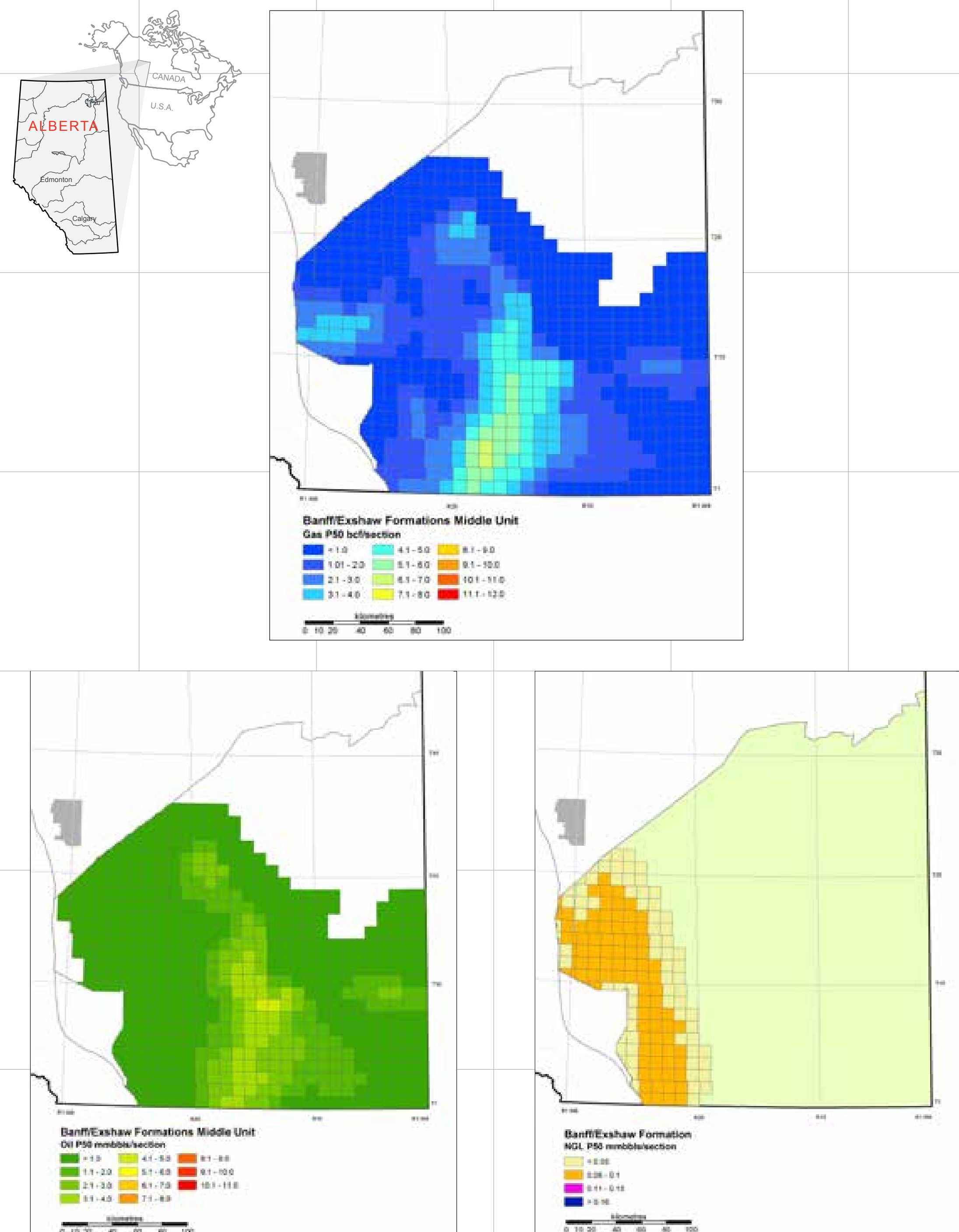


Figure AF.5

P50 gas, oil, and liquids initial in-place for the Nordegg Formation

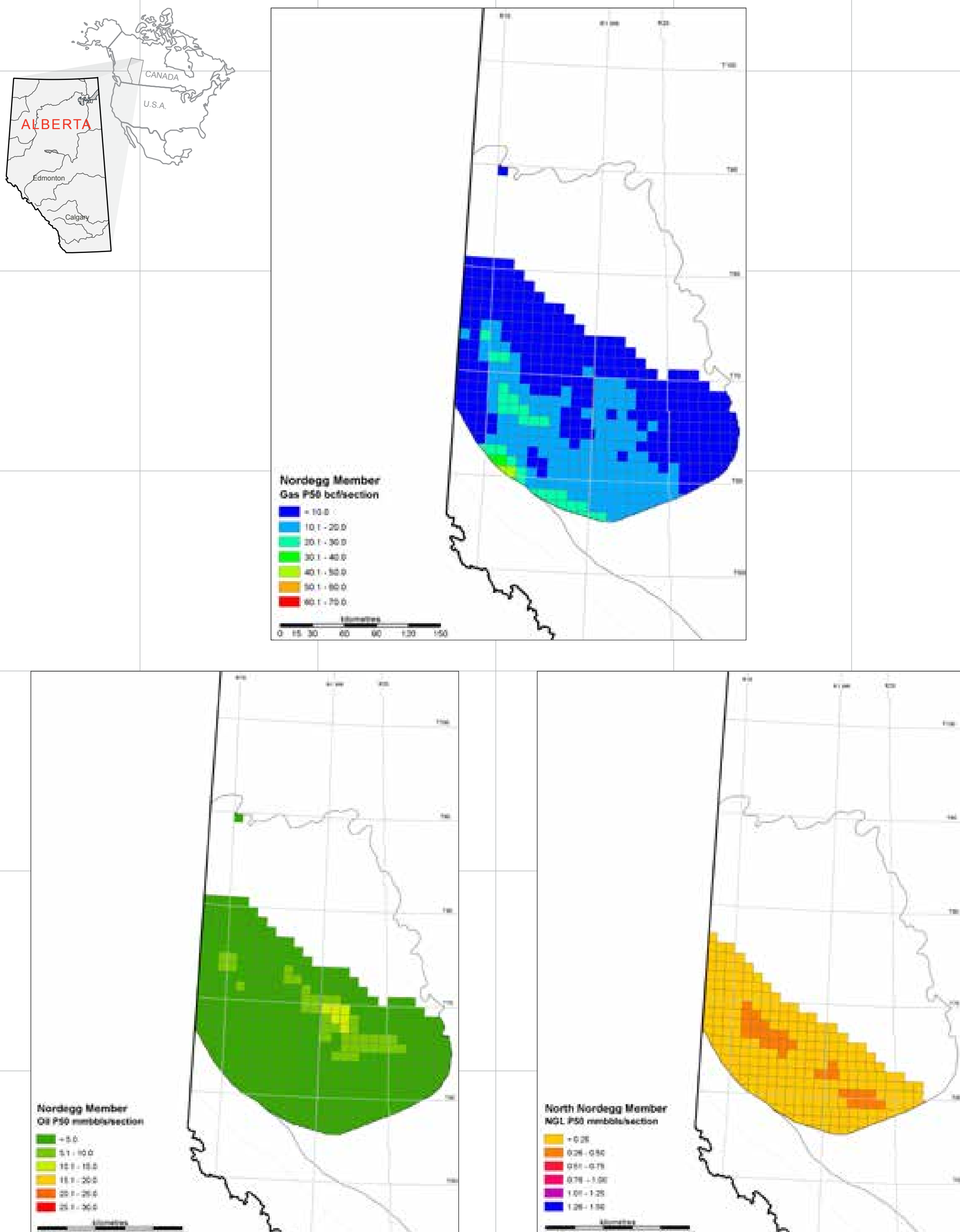


Figure AF.6

P50 gas, oil, and liquids initial in-place for the Wilrich Formation