Alberta Energy Regulator

ST98: 2017

ALBERTA'S ENERGY RESERVES & SUPPLY/DEMAND OUTLOOK

Executive Summary

EXECUTIVE SUMMARY

The Alberta Energy Regulator (AER) ensures the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources over their entire life cycle. As part of this mandate, one of the AER's key services is to provide credible information about Alberta's energy resources that can be used for good decision making. To this end, the AER issues a report every year that gives stakeholders 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.

Report Overview

2016 was another challenging year for hydrocarbon producers in Alberta. Faced with continued low global crude oil prices and weak natural gas prices, Alberta producers sought additional cost savings and curtailed capital budgets and activity. Capital expenditures fell for a second year. Conventional oil and gas wells placed on production dropped by 37.2 per cent in 2016 relative to 2015, and crude oil production and natural gas production declined as a result. Additionally, wildfires in the area of Fort McMurray disrupted oil sands production in May, with impacts lasting into summer.

However, some positive news also emerged in 2016. The Government of Canada approved two major crude oil pipeline projects: the twinning of the Kinder Morgan Trans Mountain pipeline to Canada's west coast and the replacement of the Enbridge Line 3 pipeline to the U.S. Midwest. These projects, if completed, will increase Alberta's export capacity, and the Trans Mountain pipeline will open up market access to Asia. Further good news was the agreement by the Organization of Petroleum Exporting Countries (OPEC) and several major oil-producing nonmember countries to lower crude oil production. The impact on crude oil prices, however, will depend on the level of compliance and whether U.S. shale production growth offsets any achieved reductions.

The following highlights the supply and demand outlook through to 2026 for Alberta's hydrocarbons and provides a snapshot of the province's reserves.

Report Highlight

Figure 1 Marketable natural gas percentage of production — Canada

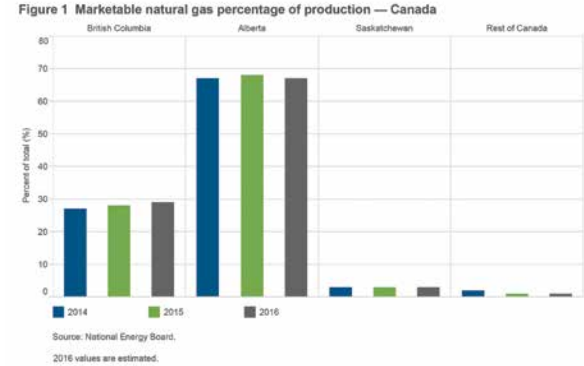
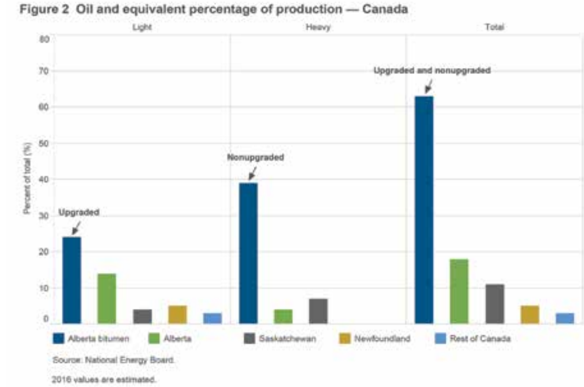


Figure 2 Oil and equivalent percentage of production — Canada

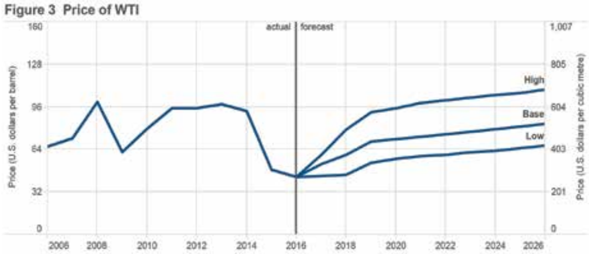


- Alberta has been and remains the largest producer of natural gas and oil in Canada. In 2016, Alberta produced 67 per cent of Canada's natural gas and 81 per cent of Canada's oil and equivalent.[1] More than 60 per cent of Canada's total oil and equivalent production was marketable bitumen.

[1] Oil equivalent includes light, medium, heavy, and ultra-heavy crude oil; condensate (pentanes plus); and upgraded and nonupgraded bitumen (referred to as marketable bitumen).

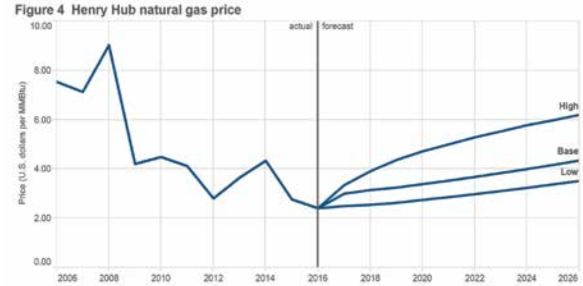
Oil and Gas Price

Figure 3 Price of WTI



Historical values source from U.S. Energy Information Administration.

Figure 4 Henry Hub natural gas price



Historical values source from the Canadian Gas Price Reporter.

- West Texas Intermediate (WTI) light sweet crude oil—the benchmark for North American crude oil price—continued to fall in 2016, albeit at a slower pace than that experienced between 2014 and 2015, from US$48.79 per barrel (bbl) in 2015 to US$43.32/bbl in 2016.
- The WTI base price is forecast at US$53.00/bbl in 2017, assuming strong compliance from OPEC and several major oil-producing nonmember countries to lower production levels. The low price scenario, at US$44.00/bbl, reflects the possibility that global crude oil inventories will not come into balance in 2017, particularly if OPEC member countries and nonmember countries do not maintain the lower production targets. The high price scenario, at US$60.00/bbl, reflects the possibility that global crude oil inventories will decrease quicker than forecast in the base case.
- The resilience of U.S. shale oil production to low price levels and the ability of shale oil producers to quickly bring on more production as crude oil prices improve is projected to provide a cap on any significant price rallies in both the base and low scenarios.
- The WTI crude oil price is forecast to gradually strengthen to US$83.26/bbl by 2026 in the base price scenario, with the prices in the low and high price scenarios reaching US$67.00/bbl and US$109.08/bbl, respectively. The low price scenario assumes strong global production growth, whereas in the high price scenario, new supply is forecast to be inadequate to offset declines in existing production due to insufficient capital expenditures for new development.

- Natural gas prices throughout North America remain low, as the market remains oversupplied due to shale gas production in the United States. Henry Hub natural gas prices, which serve as the North American benchmark for natural gas prices, declined to US$2.41/million British Thermal Units (mmBtu) in 2016 from US$2.77/mmBtu in 2015.
- In 2017, the base price is forecast to strengthen to US$3.00/mmBtu, reflecting increased U.S. seasonal heating demand, increased U.S. liquefied natural gas (LNG) exports, and growing U.S. pipeline exports to Mexico. In the low price scenario, prices are forecast to remain basically flat at 2016 levels as any demand increases are projected to be readily matched by supply. In the high price scenario, demand is forecast to grow more rapidly, causing the supply and demand balance to tighten.
- The Henry Hub natural gas price is forecast to gradually strengthen to US$4.35/mmBtu by 2026 in the base price scenario, reflecting increased demand through a combination of U.S. LNG exports, U.S. exports to Mexico, and increased domestic demand, primarily in the power sector. The prices in the low and high price scenarios are expected to reach US$3.52/mmBtu and US$6.20/mmBtu, respectively. Implicit in all three price scenarios is that the United States will continue to increase its production, mainly shale gas production, moderating price growth.

Capital Expenditures

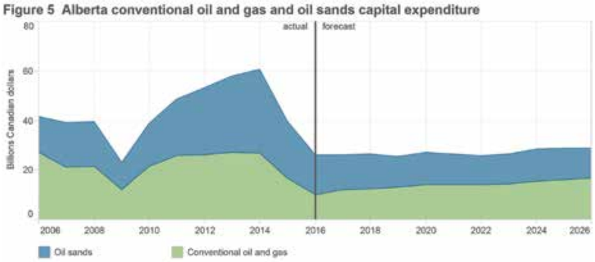


Figure 5 Alberta conventional oil and gas and oil sands capital expenditure

Historical values source from the Canadian Association of Petroleum Producers.
2016 values are estimated.

Total capital expenditures in the conventional oil and gas and oil sands sectors declined by an estimated 35 per cent between 2015 and 2016 to Cdn$26 billion.[2] This was due in part to projects being delayed because of the low oil price environment, as well as to reduced costs for materials and labour.

- Total capital expenditures are forecast to remain relatively flat in 2017, with capital expenditures forecast to increase in the conventional oil and gas sector but decline in the oil sands sector.
- Capital expenditures in conventional oil and gas are projected to increase from Cdn$10.0 billion in 2016 to Cdn$12.0 billion in 2017 due to slightly stronger prices, the attractiveness of shorter payout times compared with the oil sands sector, and continued low operating costs.
- Conversely, oil sands capital expenditures are forecast to decrease from an estimated Cdn $16.0 billion in 2016 to Cdn$14.2 billion in 2017, reflecting the continued deferral of projects and successful implementation of cost reduction strategies. Capital expenditures in the oil sands are projected to be primarily focused on sustaining capital, debottlenecking, and expanding existing projects.
- For the remainder of the forecast period, capital expenditures are projected to moderately increase, again with more capital expenditures assumed to be directed to the conventional oil and gas sector. Capital expenditures in oil sands development incorporates the assumption that the successful deployment of cost reduction strategies and use of new technologies will improve efficiencies and that capital outlays will focus on sustaining capital, expanding existing projects, namely in mining and upgrading, and the addition of small to moderate-sized in situ schemes over the forecast period.

[2] Historical statistics obtained from Canadian Association of Petroleum Producers' Statistical Handbook (2015 data). Capital expenditures for 2016 are estimates.

Reserves

Table 1 Resources, reserves, and production summary, 2016

	Crude bitumen		Crude oil		Natural gas[b]		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	13 171	82.9	9 880	351	94	103
Initial established reserves	28 092	177	3 032.9	19.1	5 654	201	34.8	38.4
Cumulative production	1 951	12.3	2 778.5	17.5	4 879	173	1.7	1.8
Remaining established reserves	**26 141**	**165**	**254.4**	**1.6**	**775**[c]	**28.2**[c]	**33.1**	**36.6**
Annual production	146.6	0.897	26.4	0.166	106.9[d]	3.8[d]	0.025[e]	0.028[e]
Ultimate potential (recoverable)	50 000	315	3 130	19.7	6 276[f]	223[f]	620	683

Note: Columns may not add up due to rounding

[a] Columns may not add up to rounding.

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

[c] Measured at field gate.

[d] Includes unconventional natural gas.

[e] Annual production is marketable.

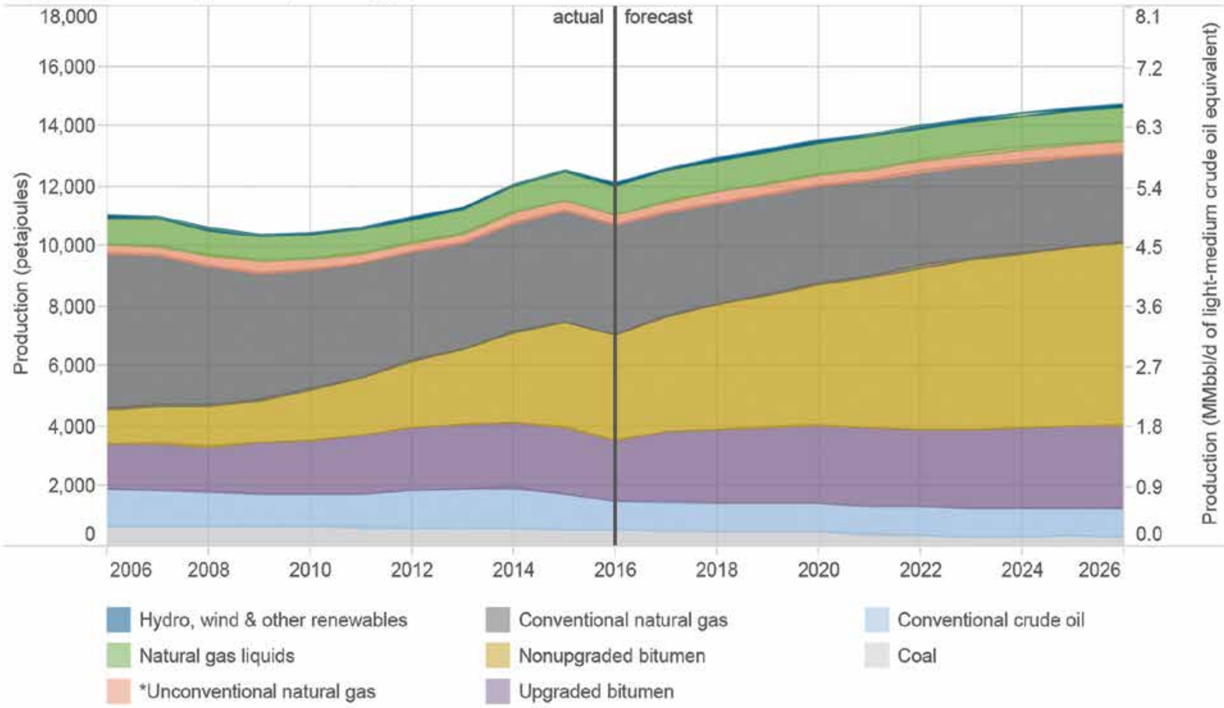
[f] Does not include unconventional natural gas.

The AER has been providing an independent appraisal of Alberta’s energy resources since 1961. The AER studies hydrocarbon extraction and ensures that energy resources under development are being optimized. The information is used by the Government of Alberta to develop policies and regional land-use plans, and by the energy industry to evaluate investment opportunities in Alberta.

Table 1 provides the reserves determined for crude bitumen, crude oil, natural gas, natural gas liquids, sulphur, and coal.

Production and Demand

Figure 6 Total primary energy production in Alberta



* Includes coalbed methane and shale gas.

2016 values are estimated.

- After production peaked in 2015, total primary energy produced in Alberta fell in 2016, primarily as a result of a drop in conventional oil and gas production, which continued to retract as a result of the weak price environment for both commodities. Upgraded bitumen production also fell due to the Fort McMurray wildfires.
- Alberta produced an estimated 12 095 petajoules (PJ) of energy from all sources, including renewable sources, in 2016, or 5.42 million barrels per day (10^6 bbl/d) of conventional light-medium quality crude oil equivalent, a 3.4 per cent decrease over 2015.
- In 2026, Alberta is projected to produce 14 724 PJ of energy from all sources, or 6.59 10^6 bbl/d of conventional light-medium quality crude oil equivalent.
- Upgraded and nonupgraded bitumen production accounted for almost half of total primary energy production in 2016. This percentage is expected to increase to 60 per cent of all primary energy production in Alberta by 2026.
- In 2016, on the basis of energy content (petajoules),[3] conventional crude oil production decreased by an estimated 16.3 per cent, while total marketable natural gas production in Alberta decreased by an estimated 1.8 per cent in 2016.

[3] 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 composition may yield slightly different numerical trends and growth rates.

- Total natural gas liquids (NGLs)[4] production increased by an estimated 4.8 per cent as companies focused on liquids-rich development.
- Total coal production decreased by an estimated 7.3 per cent due to suspended operations at some coal mines and lower coal demand for power generation.
- While this report focuses on hydrocarbon energy resources in the province, a relatively small amount of the province's energy, about 0.3 per cent, is produced from renewable energy sources such as hydro and wind power.

[4] Natural gas liquids refers to ethane, propane, butanes, and pentanes plus, or a combination of these obtained from the processing of raw gas or condensate.

Figure 7 Percentage of mined and in situ bitumen sent for upgrading in Alberta

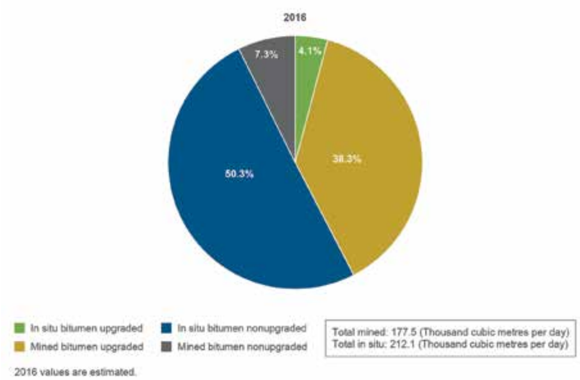
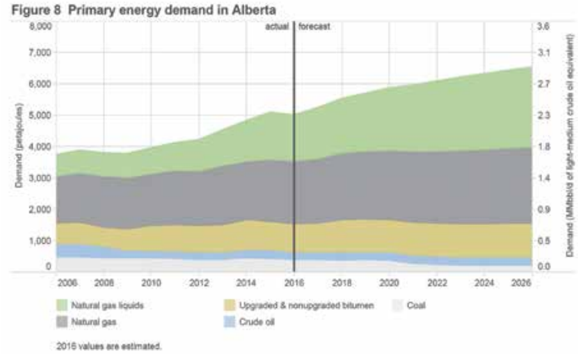


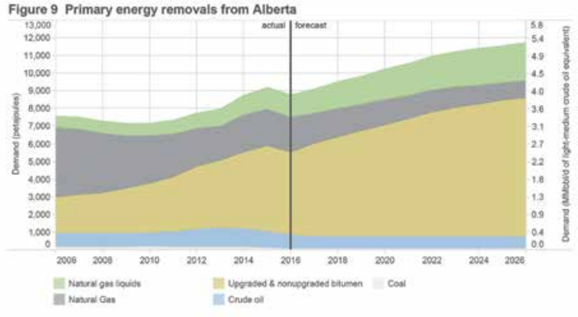
Figure 8 Primary energy demand in Alberta



- In 2016, an estimated 42 per cent of produced raw bitumen was sent for upgrading in Alberta. However, growth in in situ and mining production is expected to outpace additions to upgrading capacity, causing this percentage to shrink to 35 per cent by 2026.
- Upgraded bitumen output for 2016 was negatively affected by the Fort McMurray wildfires as well as the indefinite shut-in of Nexen's Long Lake facility.
- Alberta primary energy demand in 2016 for all fossil-based energy commodities decreased by an estimated 1.3 per cent relative to 2015.
- Total primary energy demand within the province in 2016 was estimated at 5039 petajoules, equivalent to 2.25 10^6 bbl/d of crude oil. Alberta demand is projected to increase to about 6543 PJ, equivalent to 2.93 10^6 bbl/d, by 2026, largely as a result of strengthening demand for pentanes plus as a diluent in bitumen blending. However, small increases in natural gas demand are forecast, reflecting strengthened demand for natural gas for power generation.

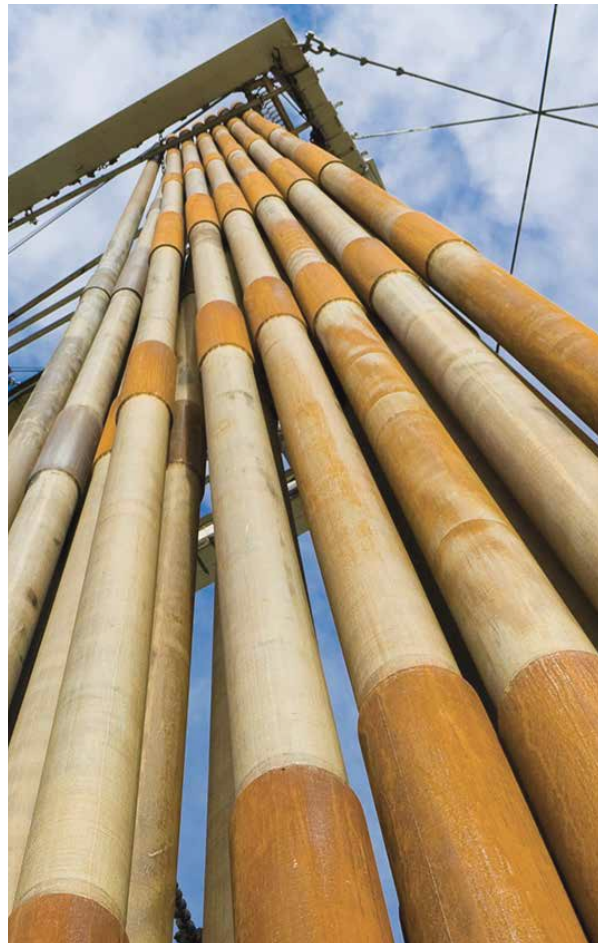
Small increases in bitumen demand are also forecast as a result of demand from the North West Redwater Partnership Sturgeon refinery.

Figure 9 Primary energy removals from Alberta



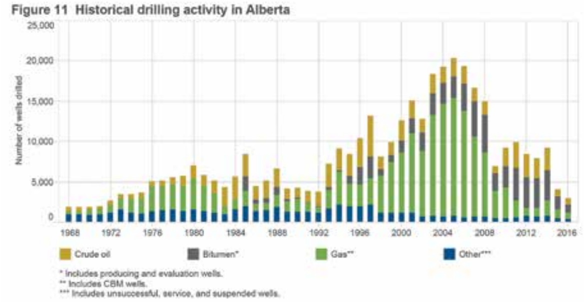
- Primary energy removals from Alberta dropped in 2016 by an estimated 4.4 per cent, primarily as a result of lower production of bitumen, crude oil, and natural gas.
- Total primary energy removals from the province in 2016 were estimated at 8799 PJ, equivalent to 3.93 10^6 bbl/d, with upgraded and nonupgraded bitumen representing over half of primary energy removals for the year.
- Removals from the province are projected to reach 11 747 PJ in 2026, or 5.26 10^6 bbl/d of crude oil equivalent, with upgraded and nonupgraded bitumen representing a growing share of primary energy removals.
- Natural gas removals from Alberta are projected to decrease over the forecast period due to declining provincial production and increasing Alberta demand, as well as continued loss of market share in the eastern United States and central Canada to U.S. shale gas production.

Figure 10 Total oil removals from Alberta



- In 2016, removals of conventional crude oil, pentanes plus, upgraded bitumen, and nonupgraded bitumen were an estimated 447.6 thousand cubic metres per day ($10^3 m^3/d$) or 2.82 10^6 bbl/d.
- By 2026, 727.0 $10^3 m^3/d$ or 4.58 10^6 bbl/d of conventional crude oil, pentanes plus, upgraded bitumen, and nonupgraded bitumen are forecast to be removed from the province.
- This projection assumes that the majority of these removals will go to the United States and that there will be sufficient transportation capacity (pipeline and rail) to ship these volumes.

Figure 11 Historical drilling activity in Alberta



- With continued weak oil and natural gas prices, total drilling dropped by an estimated 27 per cent in 2016.
- Horizontal drilling using multistage hydraulic fracturing completion technology has become the predominant method of drilling in Alberta, and this type of drilling is characterized by much higher initial productivity rates, with fewer wells needed to achieve similar production levels.

Table 2 Major Alberta economic indicators, 2016-2026

	2016[a]	2017	2018	2019-2026[b]
Real gross domestic product (GDP) growth (%)	-2.80	1.80	1.90	2.50
Inflation rate (%)	1.20	1.80	2.00	2.00
Exchange rate (US$/Cdn$)	0.75	0.73	0.75	0.8

[a] 2016 values are estimated

[b] Average over 2019-2026.

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