

ST98: ALBERTA ENERGY OUTLOOK 2026



Overview

Alberta's oil production reached an all-time high in 2025, primarily reflecting improved market access due to additional export pipeline capacity. Oil companies continued to increase production, filling the available space in the expanded Trans Mountain Pipeline, which came online in May 2024. Moreover, natural gas production increased modestly in 2025, driven by recovering natural gas prices and increased demand for diluent to transport oil sands, as producers continue to target liquids-rich areas.

In 2025, a shift in environmental policy was observed across many jurisdictions. The new US administration, inaugurated in early 2025, started shifting its domestic and global environmental policies by focusing on fossil fuel

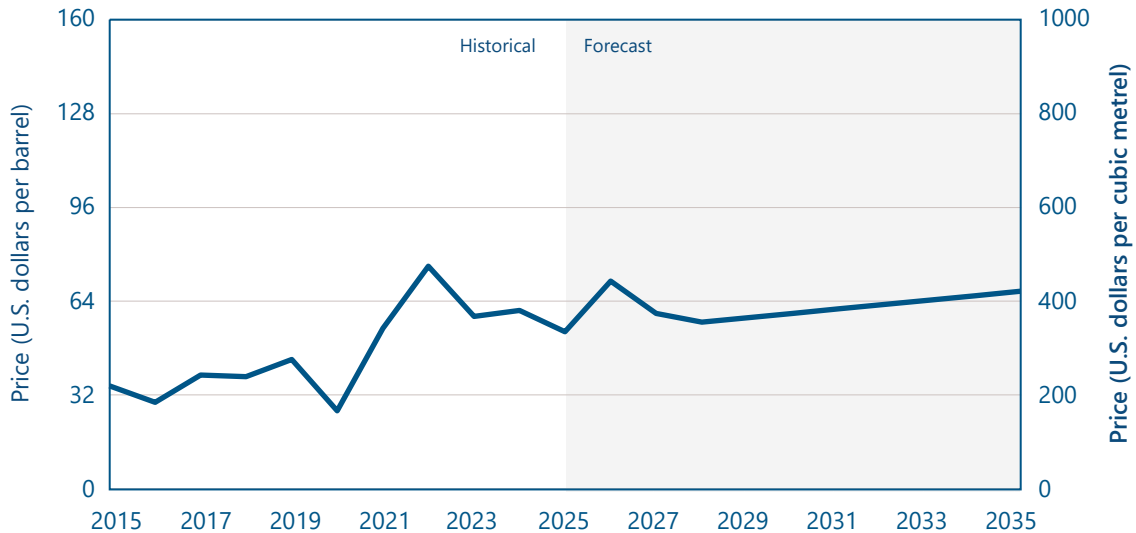
expansion over renewables, reassessing renewable energy incentives and withdrawing the US from the Paris Agreement on climate change. Several other countries, including Canada, the United Kingdom, and Germany, also reassessed their environmental goals for energy transition to ensure energy security and affordability. While environmental policies continue to evolve, oil and gas demand is expected to persist, which may provide Alberta with an opportunity to supply additional reliable energy.

In 2025, the federal and provincial governments signed a memorandum of understanding (MOU) to support oil production growth and expand pipeline export capacity for Alberta. Under the MOU, it is expected that environmental impact assessments for major projects will be accelerated.

The Government of Alberta reinforced its objective for shorter approval timelines by implementing an expedited 120-day provincial approval process for priority projects.

The Middle East conflict that began in late February 2026 has significantly constrained global energy supply and driven energy prices sharply higher. The Strait of Hormuz—a critical chokepoint through which about 20% of the world's oil and liquefied natural gas (LNG) supply flows—has been substantially disrupted. Consequently, major regional producers, including Saudi Arabia, Iraq, the United Arab Emirates, and Kuwait, have curtailed production as stranded exports accumulated, prompting the International Energy Agency to coordinate the largest emergency release of oil stocks in its history. Many countries, particularly in Europe and Asia,

FIGURE 1. WESTERN CANADIAN SELECT CRUDE OIL PRICE



Historical values from the Government of Alberta.

have been forced to ration energy consumption and impose caps on energy price increases. This has placed inflationary pressure on the global economy and could reduce economic growth globally.

Prices

Although oil prices rose in response to the Middle East conflict in 2026, prices fell in 2025, largely due to production increases by the Organization of the Petroleum Exporting Countries and its allies (OPEC+) and rising output from non-OPEC+ countries, including the U.S., Canada, Brazil, and Guyana. The Western Canadian Select (WCS) price decreased by 12% in 2025, averaging US\$53.70 per barrel (bbl), along with a lower West

Texas Intermediate (WTI) price. The differential between WTI and WCS narrowed in 2025 to an average of US\$11.14/bbl, compared with the 2024 average of US\$14.73/bbl, reflecting the additional crude oil takeaway capacity provided by the expanded Trans Mountain Pipeline.

The WCS price is forecast to average US\$71.00/bbl in 2026, ease to US\$57.00/bbl in 2028. In 2029 and beyond, prices are expected to increase gradually, reaching US\$67.50/bbl by 2035.¹ Figure 1 shows historical and forecast prices for WCS.

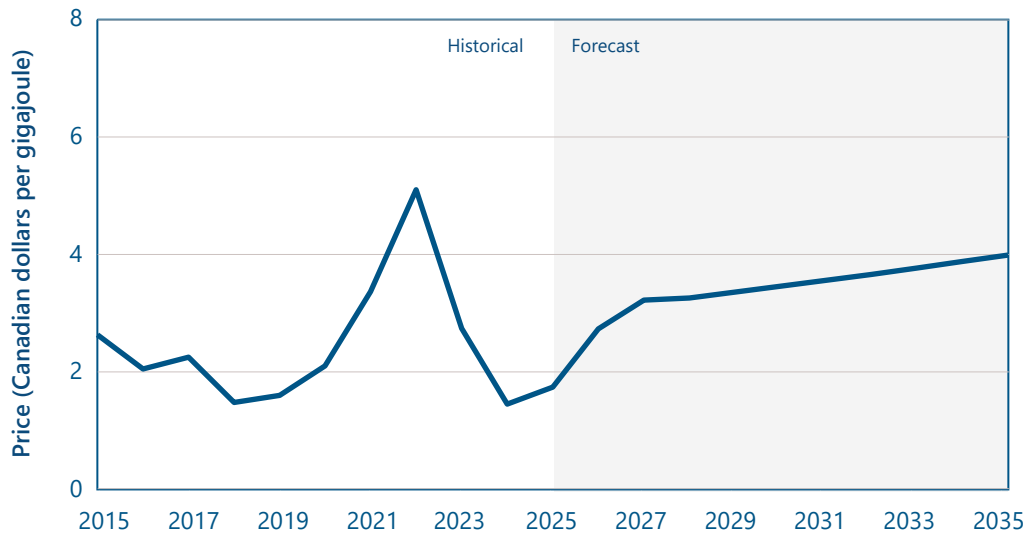
In 2025, the Alberta local natural gas price (AECO-C) increased to Cdn\$1.74 per gigajoule (GJ), primarily driven by strong oil sands fuel demand and the

start of LNG Canada's liquified natural gas exports. Despite this increase, the natural gas price differential between Henry Hub and AECO-C widened in 2025 due to rising supply and elevated inventories in Alberta.

The AECO-C price is forecast to increase to Cdn\$2.73/GJ in 2026, and then slowly rise to Cdn\$3.99/GJ by 2035. Figure 2 shows historical and forecast prices for AECO-C.

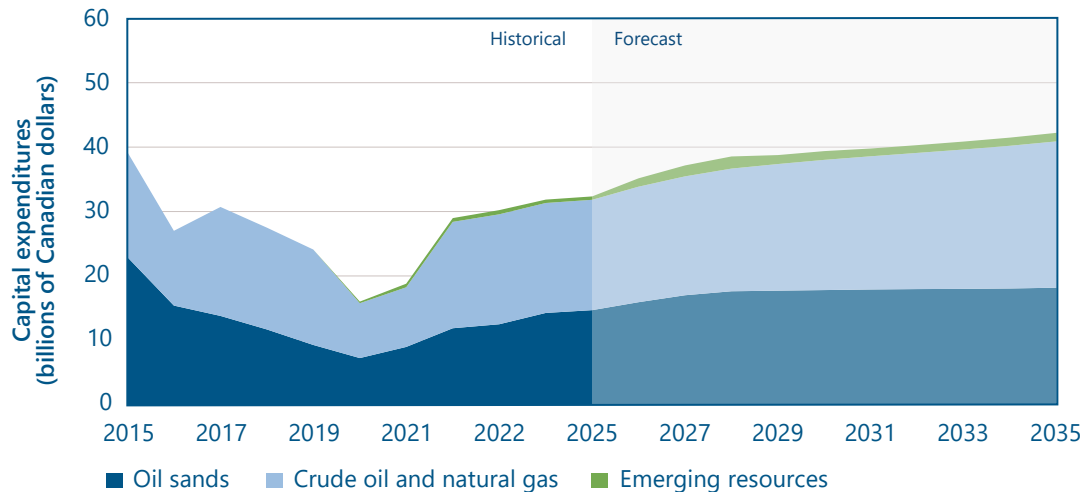
¹ Prices are determined by supply and demand factors, which are influenced by economic activity, seasonal temperatures, market access, and nonmarket factors. All price forecasts are compared with publicly available forecasts from major banks, consultants, and international forecasting agencies.

FIGURE 2. AECO-C NATURAL GAS PRICE



Historical values from the Canadian Gas Price Reporter and Intercontinental Exchange.

FIGURE 3. ALBERTA OIL AND GAS, OIL SANDS, AND EMERGING RESOURCES CAPITAL EXPENDITURES



2025 values are estimated. Oil sands, crude oil, and natural gas historical values are from CAPP. Emerging resources include geothermal, hydrogen, helium, and lithium. Historical figures are estimated. Hydrogen investment does not include CCUS.

Capital Expenditures

Total capital expenditures for crude oil, natural gas, oil sands, and emerging resources grew by 2% in 2025, reaching a ten-year high amid rising production. Investment in crude oil, natural gas, and oil sands increased; investment in emerging resources also edged up.

From 2026 onward, enhanced market access and expected long-term growth in crude oil prices are expected to provide opportunities for further investment in crude oil and oil sands projects. Higher natural gas prices and increased demand for diluent to transport oil sands are expected to drive investment for natural gas liquids

investments. Expansions, debottlenecking, new drilling, and continued improvements in operational efficiency are expected to support oil sands investment growth. Total capital expenditures in the crude oil, natural gas, oil sands, and emerging resources sectors are forecast to reach Cdn\$42.2 billion by 2035. Figure 3 shows the capital expenditure history and forecast for hydrocarbons and emerging resources.

Reserves

The AER has provided independent appraisals of Alberta's energy resources since 1961. The Government of Alberta uses information from these appraisals to develop policies and regional land-

use plans, and the energy industry uses them to evaluate investment opportunities in Alberta.

In 2024, the AER procured the services of McDaniel and Associates Consultants Ltd. (McDaniel) to evaluate Alberta's reserves and resources using industry-accepted methods published in the *Canadian Oil and Gas Evaluation Handbook* for conventional, unconventional, and oil sands formations. Based on McDaniel's 2025 full report, Alberta's diverse resource base is categorized into three areas: oil sands, conventional production, and six major resource plays: the Montney, Duvernay, Spirit River, Cardium, and Charlie Lake Formations, as well as heavy oil multilaterals

Table 1 Resources, reserves, and production summary

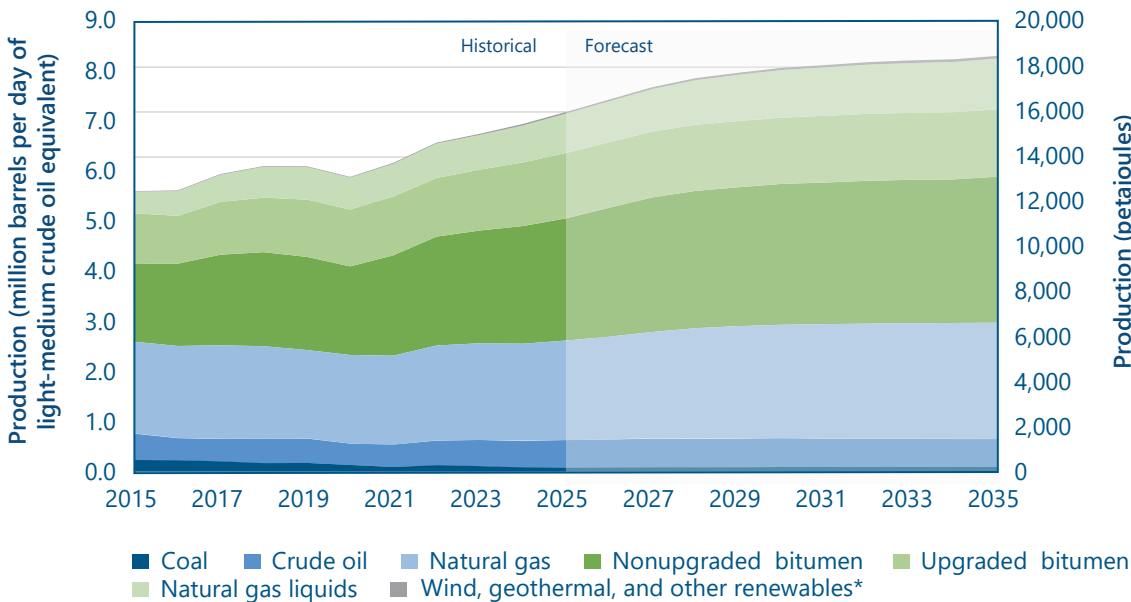
	Crude bitumen		Crude oil		Natural gas	
	(million m ³)	(billion barrels)	(million m ³)	(billion barrels)	(billion m ³)	(trillion cubic feet)
Initial in-place resources	293 125	1 845	15 628 ^a	98.3 ^a	10 749	381.5
Proved developed producing (PDP)	2 129	13.4	317.8	2.0	914.6	32.3
Proved undeveloped (PUD)	24 599	154.8	1 160	7.3	2 936	103.7
Total proved (as of Dec. 31, 2023)	26 729	167.3	1 478	9.3	3 851	136.0
Proved+probable developed producing (P+PDP)	2 384	15.0	349.6	2.2	1 014	35.8
Proved+probable undeveloped (P+PUD)	27 332	172.0	1 287	8.1	3 262	115.2
Total proved+probable reserves (as of Dec. 31, 2023)	29 716	187.0	1 637	10.4	4 276	151.1
2024 production	206.9	1.30	53.9^b	0.34^b	115.6	4.1
2025 production	215.7	1.36	56.4^b	0.35^b	118.4	4.2

Any discrepancy is due to rounding. Columns may not add up due to rounding. Crude oil proved and proved+probable reserve numbers include condensate and are sourced from McDaniel & Associates.

^a Crude oil initial in-place resources do not include condensate.

^b Crude oil production includes condensate.
m³ = cubic metres.

FIGURE 4. TOTAL PRIMARY ENERGY PRODUCTION IN ALBERTA



*Geothermal data included in 2020 to 2035.

(primarily the Clearwater Formation). Table 1 shows Alberta's resources, reserves, and production for oil and gas in Alberta. The data indicate that Alberta has sufficient reserves for many years of production.

Production

Total primary energy produced in Alberta increased by 3% in 2025,² as crude oil and oil sands producers raised output and took advantage of increased pipeline takeaway capacity resulting from the expanded Trans Mountain Pipeline. Natural gas production also increased, driven by higher gas prices and stronger demand from the oil sands sector for natural gas and diluent.

In 2025, Alberta produced an estimated 16 007 petajoules (PJ) of energy from all sources, or 7.2 million barrels per day of light-medium quality crude oil equivalent (10^6 BOE/d). Upgraded and nonupgraded bitumen production accounted for 52% of total primary energy production in 2025.

Alberta is projected to produce 18 503 PJ (8.3×10^6 BOE/d) of energy from all sources by 2035. Figure 4 shows the primary energy production in Alberta by type.

Demand

Alberta's total primary energy demand was 6 367 PJ (2.9×10^6 BOE/d) in 2025. This is about 40% of total

energy production. Increasing demand for natural gas was primarily driven by oil sands operations, power generation, and petrochemical activity.

Alberta's energy demand is projected to increase to about 7 415 PJ (3.3×10^6 BOE/d) by 2035. Figure 5 shows the primary energy demand in Alberta by type.

² 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 changes to their composition may yield slightly different numerical trends and growth rates.

FIGURE 5. PRIMARY ENERGY DEMAND IN ALBERTA

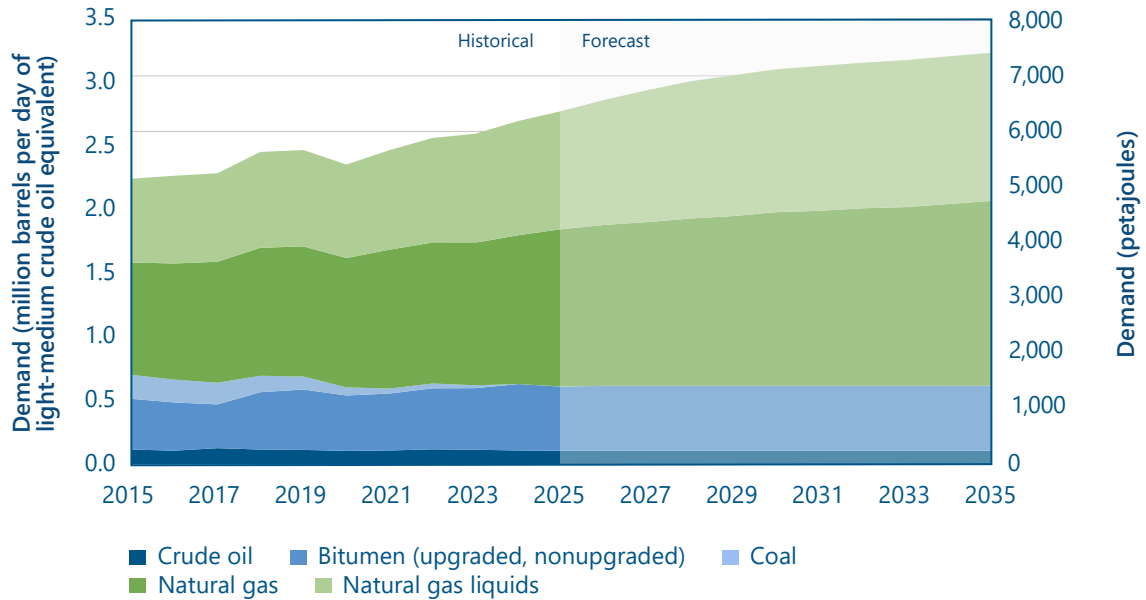
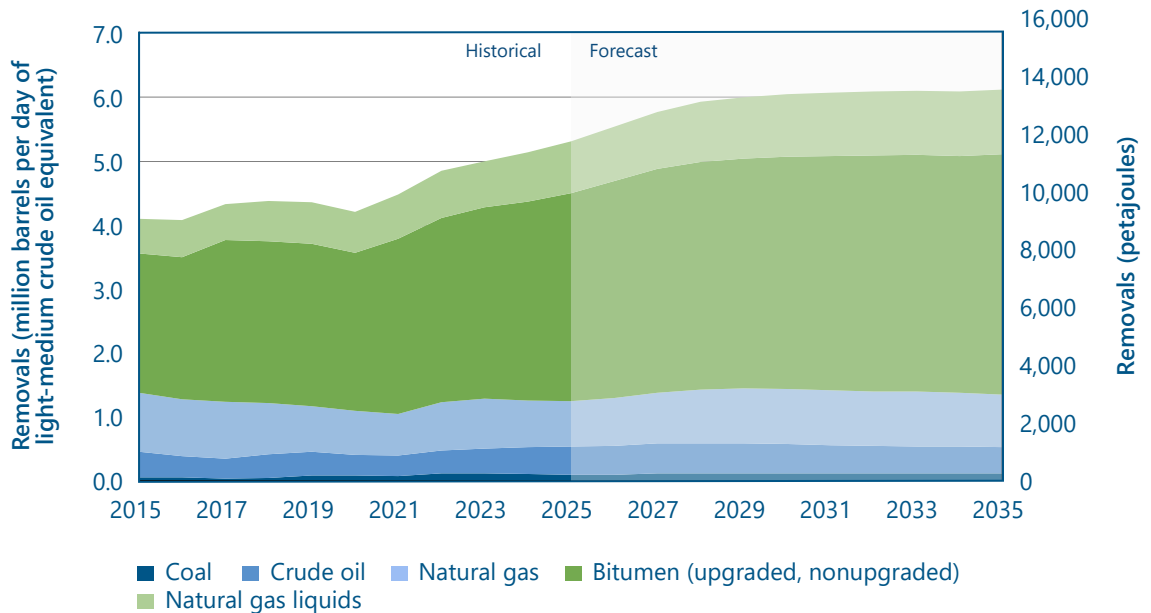


FIGURE 6. PRIMARY ENERGY REMOVALS FROM ALBERTA



Removals

Primary energy removals from Alberta increased by 3% in 2025. Sufficient pipeline capacity, along with increased production from crude oil, upgraded bitumen, and nonupgraded bitumen, contributed to increased energy removals. Total primary energy removals from the province in 2025 were estimated at 11 825 PJ (5.3 10⁶ BOE/d), with oil (bitumen and crude oil) and natural gas liquids accounting for 85% of the primary energy removals. In 2025, Alberta imported 685 PJ (0.4 10⁶ BOE/d) of pentanes plus from the US via

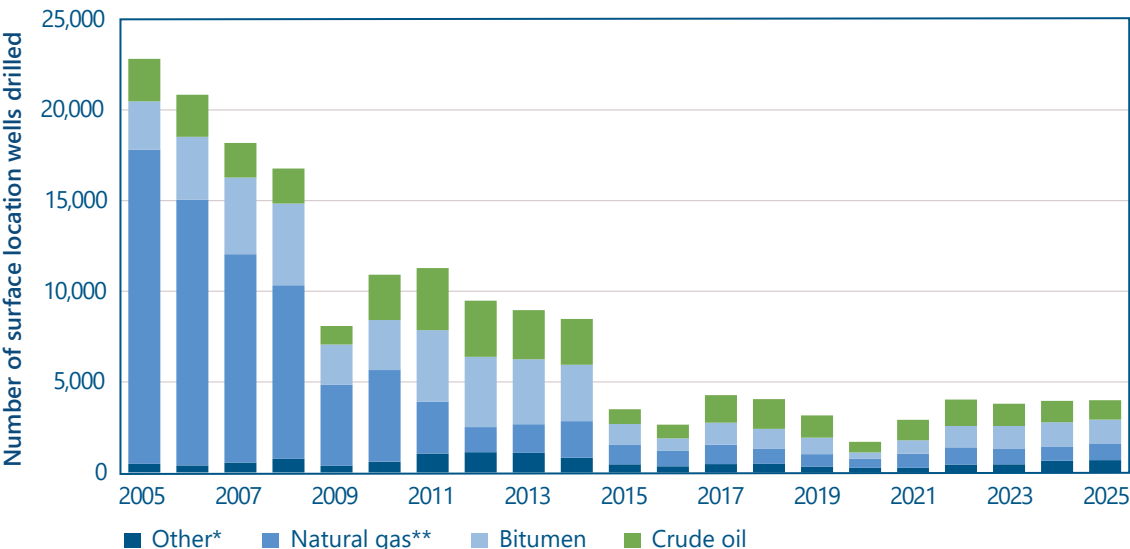
pipelines, and these volumes are included in pentanes plus removal data as a diluent used to transport bitumen in Figure 6.

Primary energy removals from the province are projected to reach 13 648 PJ (6.1 10⁶ BOE/d) by 2035, with bitumen and crude oil representing a growing share of total removals. Natural gas removals from the province are projected to increase, as production growth is forecast to outpace demand growth. Figure 6 shows the primary energy removals by type from Alberta.

Drilling Activity

Well legs with multiple bottom locations can connect to a single surface-location-drilled well that is specified in a well licence. Figure 7 shows that the number of surface-location-drilled wells—based on well licence records and intended spud dates—increased by 1% in 2025. Natural gas drilling increased by 19%, crude oil drilling decreased by 10%, and oil sands drilling decreased by 2%.

FIGURE 7. HISTORICAL DRILLING ACTIVITY FOR SURFACE LOCATION WELLS IN ALBERTA



Surface-location-drilled wells are based on well licence records, which include the intended spud date and fluid type.

* Includes unsuccessful, service, and suspended wells.

** Includes coalbed methane wells.