Alberta Energy Regulator

Alberta Energy Outlook

ST98 | 2025

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About This Report

The Alberta Energy Regulator (AER) provides for the safe, efficient, orderly, and environmentally responsible development of hydrocarbon, geothermal, and mineral resources over their entire life cycle. As part of this mandate, we provide our stakeholders with credible information about Alberta's energy resources that can be used for decision making.

Our Alberta Energy Outlook 2025 report (ST98) provides independent and comprehensive information on the state of hydrocarbon reserves and the supply and demand outlook for Alberta's diverse energy resources: crude bitumen, crude oil, natural gas, natural gas liquids, coal, and emerging resources. The report includes supply and demand data for 2024 and a ten-year supply and demand forecast for 2025 to 2034 (the forecast period). In addition, this report discusses prices and capital expenditures in the oil and gas sector, carbon capture, utilization, and storage (CCUS), pipelines, and other infrastructure related to Alberta's energy resources. Reserves data have been updated this year to reflect an external analysis and we will revise the data as new information becomes available. This year's production forecast does not account for the ongoing evaluation of oil and gas reserves and resources by McDaniel and Associates Consultants Ltd. The impact of the new data on the production forecast will be evaluated alongside other factors, such as pipeline takeaway capacity, market conditions, and investment trends, in next year's Alberta Energy Outlook publication.

Electronic data files for crude oil and natural gas reserves and PDF maps of designated fields, oil sands areas, development entities, and documents related to ST98 are available for free from the AER product and services catalogue. A historical reserve file is available for purchase on the same product catalogue.

For general inquiries, contact Inquiries@aer.ca.

Some of the data for this report contains information provided by third parties. For additional information about the limitations and restrictions applicable to these documents, please refer to the AER Copyright and Disclaimer page.

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Abbreviations

ABNIT	Alberta Nova Inventory Transfer
ACTL	Alberta Carbon Trunk Line
AGS	Alberta Geological Survey
AIOC	Alberta Indigenous Opportunities Corporation
AOSP	Athabasca Oil Sands Project
BOE	barrels of oil equivalent
CAPP	Canadian Association of Petroleum Producers
CBM	coalbed methane
CCS	carbon capture and storage
CCUS	carbon capture, utilization, and storage
CMIF	Critical Minerals Infrastructure Fund
COGEH	*Canadian Oil and Gas Evaluation Handbook*
CSS	cyclic steam stimulation
DE	development entity
DLE	direct lithium extraction
EV	electric vehicles
FOB	free-on-board
GHG	greenhouse gas
GJ	gigajoule
GoA	Government of Alberta
GRDA	*Geothermal Resource Development Act*
GRDR	*Geothermal Resource Development Rules*
GW	gigawatt

HMSF	horizontal multistage fracturing
IEA	International Energy Agency
IHS	inclined heterolithic stratification
LCE	lithium carbonate equivalent
LNG	liquefied natural gas
LPG	liquefied petroleum gas
NYMEX	New York Mercantile Exchange
OFR	Open File Report
OPEC	Organization of the Petroleum Exporting Countries
PJ	petajoules
PSAC	Petroleum Services Association of Canada
SAGD	steam-assisted gravity drainage
SCO	synthetic crude oil
TIER	*Technology Innovation and Emissions Reduction Regulation*
TMX	Trans Mountain pipeline expansion
WCS	Western Canadian Select
WTI	West Texas Intermediate

Executive Summary

The Alberta Energy Regulator (AER) provides for the safe, efficient, orderly, and environmentally responsible development of hydrocarbon, geothermal, and mineral resources over their entire life cycle. As part of our mandate, we provide our stakeholders with credible information about Alberta's energy resources that can be used for decision making.

A key information resource is the *Alberta Energy Outlook (ST98)*, an annual report with independent and comprehensive information on the state of hydrocarbon reserves and the supply and demand outlook for Alberta's diverse energy resources (crude bitumen, crude oil, natural gas, natural gas liquids,[1] coal, and emerging resources). The reserves data have been updated this year to reflect an external analysis and will be revised as new information becomes available. Additionally, this report discusses prices, capital expenditures in the oil and gas sector, pipelines, carbon capture, utilization, and storage (CCUS), and other infrastructure related to Alberta's energy resources.

Alberta's oil and gas industry has been a cornerstone of the province's economy and a significant contributor to provincial and federal government revenues since 1947. It is reported that the industry contributed about $280 billion in royalties to the provincial government from 1947 to 2023. Furthermore, the industry is a notable contributor to federal income through federal taxes, supporting vital national programs including the federal equalization program since its inception in 1957.

Report Overview

In 2024, Alberta's oil industry experienced notable growth due to pipeline capacity improvements and favourable oil prices. Oil companies increased their production, seeking to use the newly operational Trans Mountain pipeline expansion (TMX), which came online in May 2024. Moreover, natural gas production increased slightly as liquid-rich gas production rose despite low natural gas prices. At the start of 2025, global energy markets exhibited high volatility due to heightened uncertainties, including U.S. trade policies and geopolitical tensions in Ukraine and the Middle East. These uncertainties influenced investment, trade, and economic growth, while reigniting concerns about energy affordability, reliability, and security.

Because of significant uncertainty, particularly regarding U.S. tariff policies, this year's report examines two scenarios: a short-term tariff uncertainty scenario (base case) and a one-year

[1] Natural gas liquids include ethane, propane, butane, and pentanes plus—on their own or combined—obtained from processing raw gas or condensate.

tariff scenario (tariff case). The primary difference between these scenarios lies in their tariff assumptions.

- **Base case**: This scenario assumes business as usual and no tariffs. However, the U.S. tariff threats on energy products (oil and gas) persist throughout the first half of 2025 but are ultimately averted through diplomatic negotiations by midyear. Consequently, energy supply and demand are minimally affected.
- **Tariff case**: This scenario assumes a 10% U.S. tariff on energy products (oil and gas) and 25% tariffs on other Canadian goods imposed in the first half of 2025 despite diplomatic efforts. This scenario includes subsequent U.S. and Canadian retaliatory tariffs, other nontariff measures,[2] and additional U.S. tariffs on other trading partners. All tariffs and nontariff measures between Canada and the United States persist until the end of the first quarter of 2026 before mostly being phased out as the review and renegotiation of the Canada-United States-Mexico Agreement takes place. It is expected tariffs will have some long-term effects and structural changes to the global economy (changes in trade and investment flows).

These tariff assumptions affect prices, costs, commodity profitability, investment, supply and demand, project risk factors, and commercial start dates (where applicable) for most chapters of the report, including comparisons of the outcomes of these scenarios. These two scenarios provide a range of potential outcomes. If actual tariff conditions deviate from our assumptions, we anticipate the realized results could vary.

Reserves data for the province is being updated by McDaniel and Associates Consultants Ltd. and results are currently available for the Duvernay Formation, Montney Formation, Spirit River Formation, and the region of the Clearwater Formation being developed through multilateral well designs. The updated natural gas reserves for the Montney, Duvernay, and Spirit River Formations are significant not only for Alberta but also for Canada. Based on the Government of Alberta press release in March 2025, with new estimates for these formations, Canada has more than doubled its gas reserves, moving it from number 15 to number 9 globally in reserves.

Alberta maintains its dominant position with proved oilsands reserves, substantially surpassing Texas's oil reserves. Emerging opportunities like multilateral drilling in the Clearwater Formation will further bolster Alberta's strong position.

Oil prices experienced minor percentage changes compared with natural gas prices in 2024. The North American light oil benchmark price (West Texas Intermediate [WTI]) decreased by

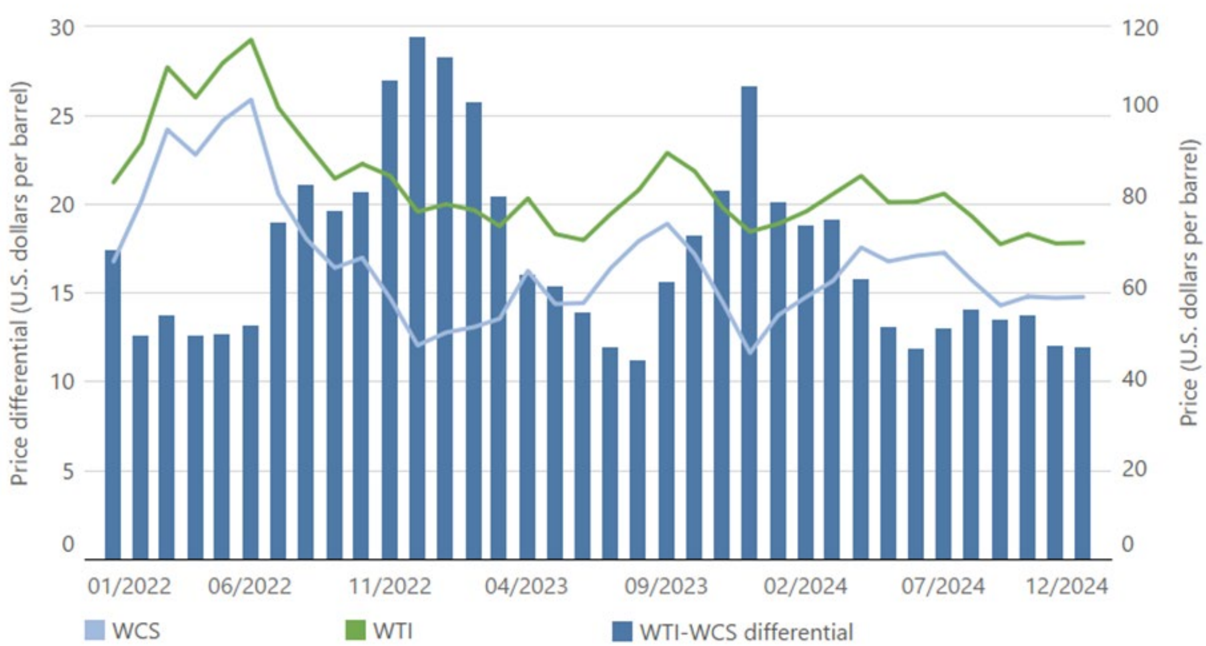
[2] Nontariff measures can include quotas or restrictions on imported goods (i.e., liquor), export taxes on electricity, and changes in consumer and business behaviour (i.e., buying Canadian).

2.4%, and the Alberta heavy-oil benchmark price (Western Canadian Select [WCS]) increased by 3.4%. Conversely, the North American natural gas price (Henry Hub) declined by 9.7%, and the Alberta local price (AECO-C) fell substantially by 47%.

The WTI price dropped to US$75.72 per barrel (bbl) in 2024. In early 2024, WTI price rose amid Middle East tensions and potential supply constraints. Later in the year, WTI price moved lower due to increased U.S. shale production and slowing economic growth in major economies, such as China and European countries. This decline was partly offset by delayed production increases from the Organization of the Petroleum Exporting Countries and its allies (OPEC+). Throughout 2024, WTI mostly remained within a relatively narrow trading range between US$65.00 and US$85.00/bbl. At the start of 2025, U.S. trade policies, geopolitical uncertainties, OPEC+ supply decisions, and recession fears weighed on oil prices. Considering these factors, we forecast a base case WTI price of US$66.00/bbl for 2025.

The price differential between WTI and WCS prices averaged US$14.73/bbl in 2024, roughly US$4/bbl lower than in 2023 due to the start-up of the TMX pipeline in 2024. Figure 1 shows the oil price history and price differential.

Figure 1 Canadian oil price differential



Historical values from the Government of Alberta, U.S. Energy Information Administration, and MarketWatch.

The Henry Hub price for natural gas decreased by 9.7% from the previous year to an average of US$2.41 per million British thermal units (MMBtu) in 2024, the second-lowest price in the last two decades. The mild winter, robust U.S. production, limited growth in natural gas consumption, and high inventories put downward pressure on prices. In early 2025, colder weather and elevated demand from new North American liquefied natural gas (LNG) projects lifted the average Henry Hub price above US$4/MMBtu in February. With increased demand, the Henry Hub price is forecast to average US$3.80/MMBtu in 2025 under the base case.

The average AECO-C natural gas price was Cdn$1.45 per gigajoule (GJ) in 2024, representing a decrease of 47% from 2023. The natural gas price differential between Henry Hub and AECO-C widened in 2024 due to ample inventories in Alberta and reduced exports to the United States.

Total oil production (including crude oil, oil sands, and pentanes plus) continued to rise as companies increased production and shipped oil using the newly operational TMX pipeline. The production increase mainly came from nonupgraded bitumen, followed by upgraded bitumen.

Despite lower prices in 2024, production of marketable natural gas increased marginally by 0.2%. While dry natural gas production experienced declines, this was offset by increased output from liquids-rich regions and elevated associated gas production from oil wells.

In 2024, total capital expenditures for crude oil, natural gas, oil sands, and emerging resources continued to grow, reaching Cdn$31 billion, a nine-year high. Crude oil and natural gas investment reached Cdn$16.8 billion. Oil sands investment increased to Cdn$13.3 billion due to continued focus on debottlenecking and improving operational efficiency across oil sands facilities.

Market access remained sufficient for oil and gas exports in 2024. Takeaway capacity was enhanced by the start-up of the TMX pipeline in May 2024. For natural gas transportation, capacity met the export demand, and transportation capability improved further after the completion of the Coastal GasLink pipeline in British Columbia, connecting to LNG Canada facilities.

Alberta presents growth opportunities for emerging resources: hydrogen, geothermal energy, helium, and lithium. Under the base case, hydrogen production is estimated to increase from 2.6 million tonnes in 2024 to 4.4 million tonnes in 2034. Despite the current low production levels, geothermal production is forecast to increase to 76.2 gigawatt-hour and helium to 10.4 thousand cubic metres per day (10^3 m^3/d) by 2034 from 2024 levels. Although there is no commercial lithium production in Alberta in 2024, lithium production is forecast to reach 14.8 thousand tonnes per year by 2034. For emerging resources, production under the tariff case is lower than the base case. Hydrogen production is, on average, reduced by 4%, geothermal by 9%, and helium by 13% from the base case over the forecast period.

Alberta CCUS projects continue to demonstrate success in mitigating carbon emissions. In 2024, the Shell Quest project permanently sequestered 1.0 million tonnes of carbon dioxide and Enhance Energy's Clive Field project, part of the Alberta Carbon Trunk Line, permanently sequestered 1.4 million tonnes of carbon dioxide.

Report Highlights

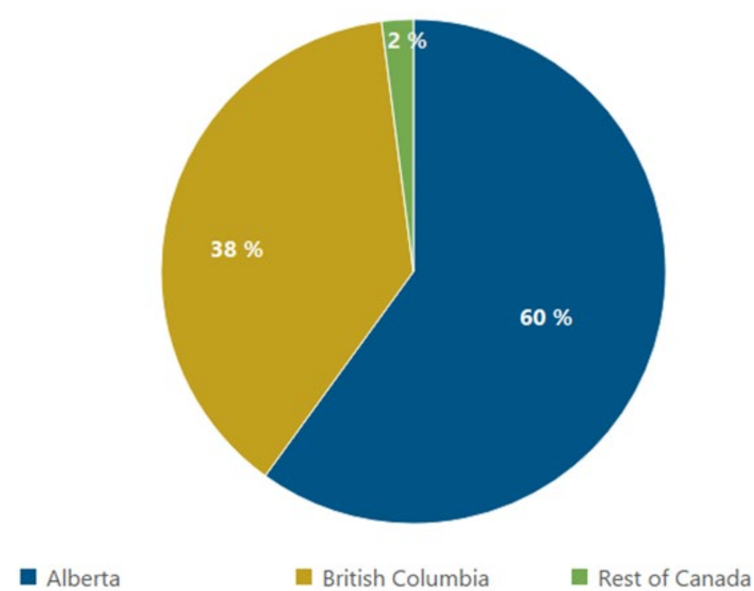
This section provides highlights of oil and gas production, prices, capital expenditures, demand, and drilling activity for 2024 and their outlook for 2025 to 2034 (the forecast period).

Oil and Gas Production in Canada

Alberta remains the largest natural gas and oil producer in Canada (see Figure 2 and Figure 3). Alberta produced 60% of Canada's natural gas in 2024, although British Columbia's share of marketable gas production has increased from 27% in 2013 to 38% in 2024. Alberta accounted for 84% of Canada's oil and equivalent,[3] and 66% was marketable bitumen in 2024.

In 2024, raw crude bitumen production in Alberta was close to 3.6 million barrels per day (10^6 bbl/d), a 4% increase from 2023.

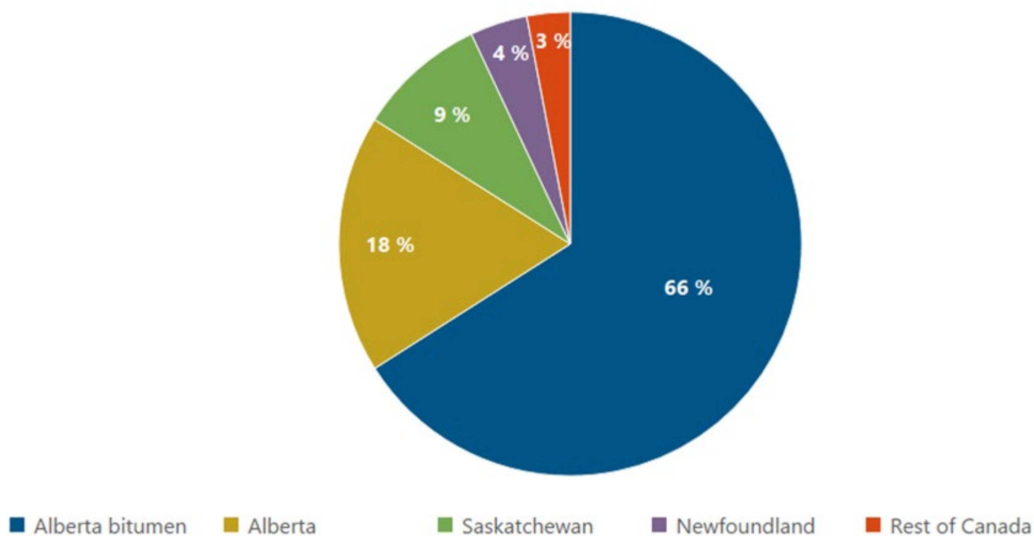
Figure 2 Marketable natural gas percentage of production in 2024 — Canada



2024 values are estimated.
Source: Canada Energy Regulator.

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

Figure 3 Total oil and equivalent percentage of production in 2024 — Canada

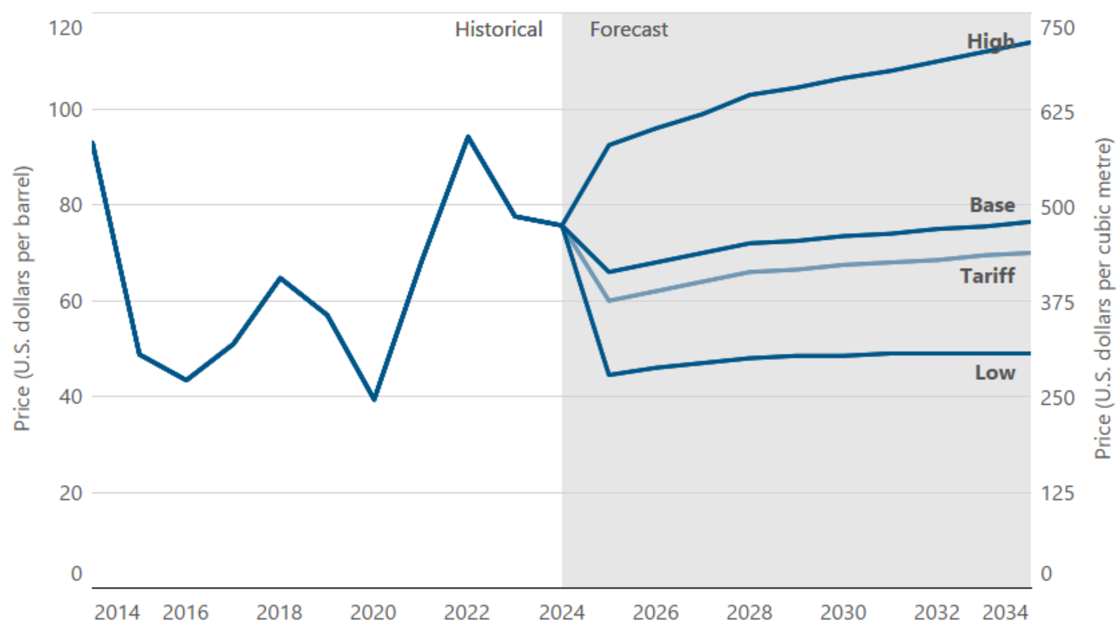


2024 values are estimated.
Source: Canada Energy Regulator.
Alberta bitumen includes synthetic crude oil.

Oil and Gas Prices

Figure 4 shows the WTI price history and forecast price ranges for the base case and tariff case.

Figure 4 West Texas Intermediate crude oil price (base case vs. tariff case)

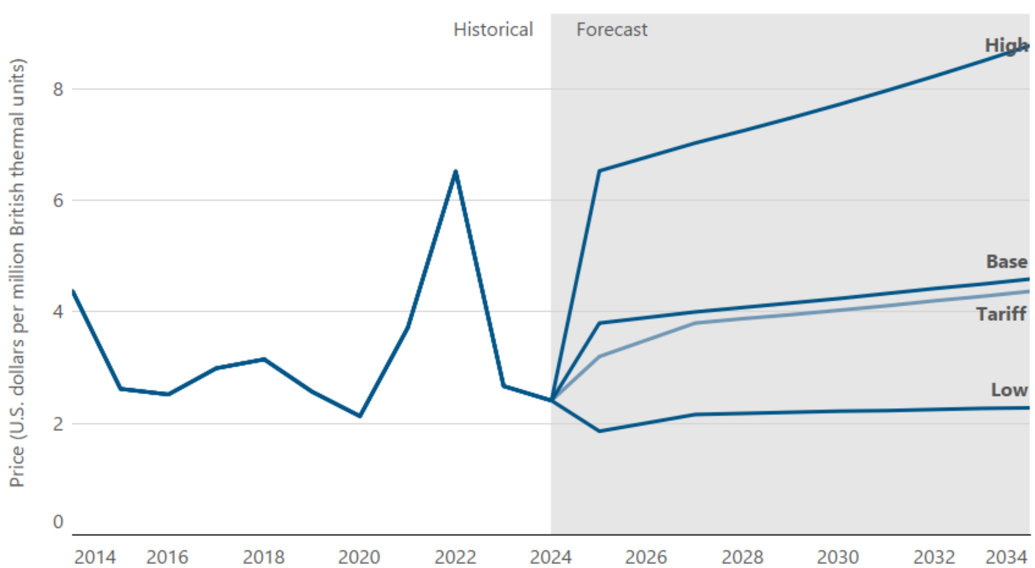


Historical values from U.S. Energy Information Administration and MarketWatch.

- The price of WTI decreased by 2.4% in 2024, averaging US$75.72/bbl.
- The price of WCS increased by 3.4% in 2024, averaging US$60.99/bbl.
- Under the base case, the WTI price is projected to be lower in 2025 at US$66.00/bbl. Global liquid fuel demand growth is expected to slow down in 2025, with lower global economic activity due to trade policy uncertainty. The decision by OPEC+ to increase supply would further depress the WTI price.
- Under the tariff case, the WTI price is expected to decline to US$60.00/bbl in 2025 as tariffs weigh on international trade and global oil demand growth.
- The low-price case of US$44.50/bbl in 2025 considers global oil demand to contract due to a global economic recession, OPEC+ production exceeding their target output level, and stronger-than-expected non-OPEC+ production growth.
- The high-price case of US$92.50/bbl in 2025 considers diplomatic negotiations will quickly resolve trade tensions, global economic activity will rebound faster than projected, OPEC+ increases oil supply at a slower than expected pace, and deteriorating geopolitical tensions will further disrupt regional oil supply.
- The WTI crude oil price is forecast to rise to US$68.00/bbl in 2026, as oil demand growth is expected to rebound as tariff uncertainties are removed. The price is projected to increase moderately from 2027 onwards, reaching US$76.50 by 2034 (base case forecast).
- The differential between WTI and WCS narrowed in 2024 to an average of US$14.73/bbl compared with the 2023 average of US$18.65/bbl, reflecting the start-up of the TMX pipeline in May 2024, adding export capacity to the Canadian West Coast.

Figure 5 shows the Henry Hub price history and forecast price ranges.

Figure 5 Henry Hub natural gas price (base case vs. tariff case)



Historical values sourced from the U.S. Energy Information Administration and MarketWatch.

- The Henry Hub price decreased by 9.7%, averaging US$2.41/MMBtu in 2024. Mild winter weather, robust U.S. production, limited natural gas consumption growth, and high inventories put downward pressure on prices.
- Under the base case, the Henry Hub price is expected to rise to an average of US$3.80/MMBtu in 2025, with colder weather and elevated demand from newly completed LNG projects. Despite the price increase, natural gas export capacity remains limited, and natural gas prices in North America are only partially dependent on international prices. North American regional factors are the primary drivers of the price forecast.
- Under the tariff case, the Henry Hub price is anticipated to be lower than the base case at around US$3.20/MMBtu in 2025. Lower North American gas demand under the tariff case due to slowing economic growth will depress the price.
- In the low-price case, the price is forecast to average US$1.86/MMBtu in 2025 because of lower-than-expected North American demand due to an economic slowdown and strong U.S. natural gas production growth.
- In the high-price case, the price is forecast to average US$6.53/MMBtu in 2025 because of a colder winter and a stronger-than-expected economic activity supporting North American demand.
- The Henry Hub price is forecast to rise to US$3.90/MMBtu in 2026 as U.S. demand growth rebounds; however, solid natural gas production growth will limit the price gains. The price is forecast to increase from 2027 onwards, reaching US$4.59/MMBtu by 2034 (base case forecast).

Capital Expenditures

Figure 6 shows the capital expenditure history and forecast for hydrocarbons and emerging resources.

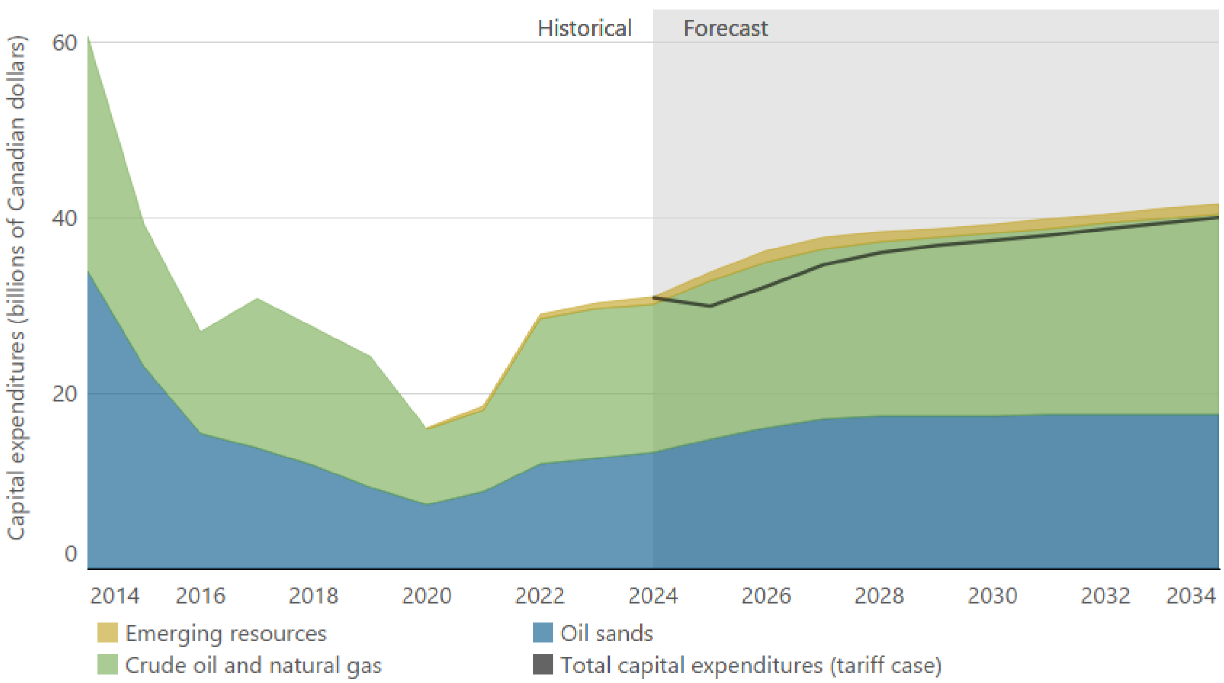
- Total capital expenditures in the crude oil, natural gas, oil sands, and emerging resources sectors increased by 2.2% in 2024, rising to Cdn$30.9 billion.[4] Reasonably high oil prices, alongside improved market access from the TMX pipeline, supported the expenditure growth.
- Estimated crude oil and natural gas capital expenditures remained steady in 2024 at Cdn$16.8 billion. Expenditures were sustained by sufficiently high oil prices and increased oil drilling activity.
- With the completion of the TMX pipeline in 2024 and continued debottlenecking, alongside improved operational efficiency across oil sands facilities, estimated oil sands

[4] Historical data on oil sands, crude oil, and natural gas investments are from the Canadian Association of Petroleum Producers. Capital expenditures for 2024 are estimates. The 2025–2034 forecasts are produced by the AER.

capital expenditures grew by 6.4% from Cdn$12.5 billion in 2023 to Cdn$13.3 billion in 2024.

- Total capital expenditures in the crude oil, natural gas, oil sands, and emerging resources sectors will reach Cdn$41.5 billion in 2034 in the base case and Cdn$40.1 billion in the tariff case.
- Total oil sands, crude oil, and natural gas capital expenditures are estimated to be Cdn$30.1 billion in 2024. In the base case, investment is projected to grow steadily at an average of 3% over the forecast period. By the end of the forecast period, total capital expenditures are expected to remain relatively low compared with the 2014 peak level.
- Capital spending for emerging resources was an estimated Cdn$0.79 billion in 2024 and is projected to increase to Cdn$1.2 billion by 2034 in the base case, with some uncertainty. This spending is risked and projected based on public announcements for hydrogen, helium, lithium, and geothermal projects and estimated capacity additions.

Figure 6 Alberta oil and gas, oil sands, and emerging resources capital expenditure (base case vs. tariff case)



2024 values are estimated.
Oil sands, crude oil, and natural gas historical values from CAPP.
Emerging resources include geothermal, hydrogen, helium, and lithium. Historical figures are estimated.

Reserves

The AER has been providing an independent appraisal of Alberta's energy resources since 1961. The AER studies hydrocarbon extraction and ensures energy resources are being extracted in an efficient and environmentally responsible manner.

The Government of Alberta uses the information to develop policies and regional land use plans, and the energy industry uses it to evaluate investment opportunities in Alberta.

In 2024, the AER procured the services of McDaniel and Associates Consultants Ltd. (McDaniel) to evaluate the reserves and resources of Alberta using industry-accepted methods published in the *Canadian Oil and Gas Evaluation Handbook* for conventional, unconventional and oil sands formations. Results for the Montney, Duvernay, and Spirit River Formations and the heavy-oil regions of the Clearwater Formation through multilateral well designs are currently available, and the *Alberta Energy Outlook* will be updated as more results are delivered in 2025.

Table 1 shows the oil and gas unconventional reserves for four formations: Montney, Duvernay, Spirit River, and the heavy-oil regions of the Clearwater. The data suggests Alberta has sufficient reserves for many years of production.

Table 1 Remaining proved + probable reserves volumes (as of December 31, 2023)

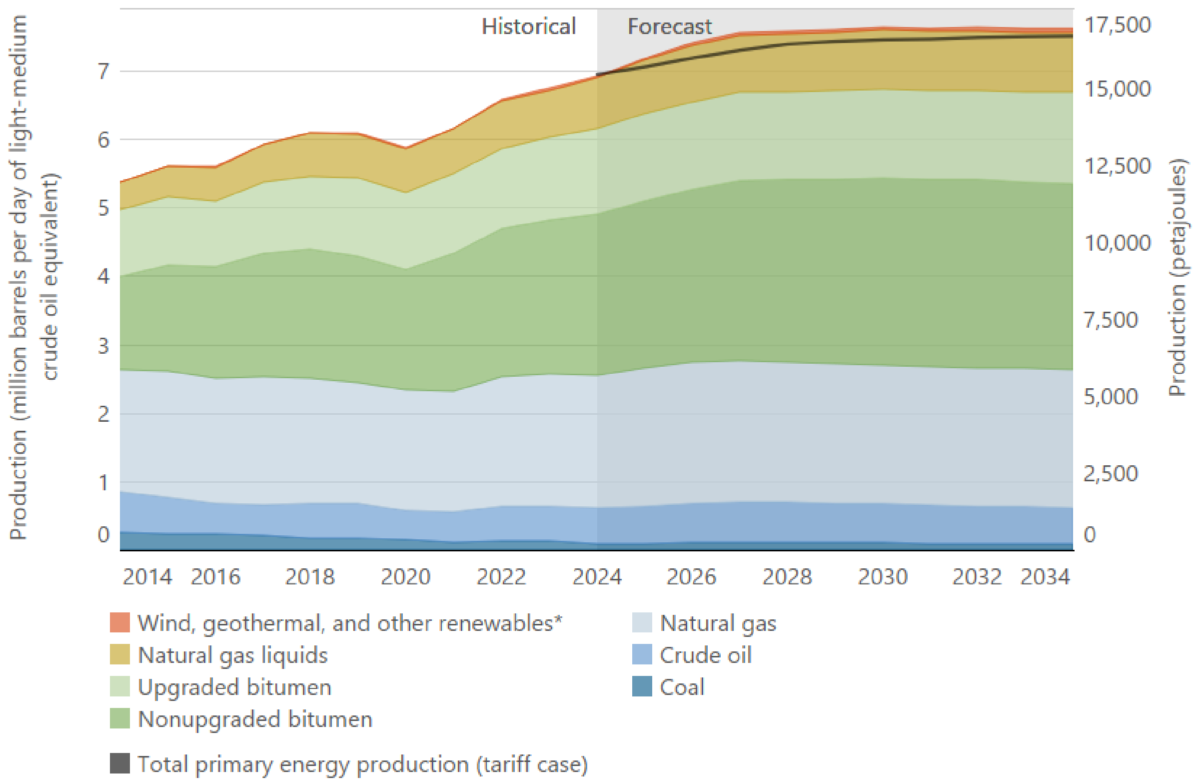
Category	Oil		Condensate		Gas		Oil equivalent	
	MMbbl	10^6 m^3	MMbbl	10^6 m^3	Bcf	10^9 m^3	MMBOE	10^6 m^3 OE
Duvernay Formation								
2P Producing & Undeveloped Reserves	1,735	276	890	141	17,676	498	5,571	885
Montney Formation*								
2P Producing & Undeveloped Reserves	409	65	2,892	460	64,502	1,817	14,052	2,234
Spirit River Formation								
2P Producing & Undeveloped Reserves	-	-	-	-	41,746	1,176	6,958	1,106
Clearwater Formation**								
2P Producing & Undeveloped Reserves	1,614	257	-	-	1,164	33	1,808	287

Any discrepancy is due to rounding.
Note: 2P – best estimate (proved + probable) of reserves.
*Includes unconventional regions of the Montney Formation & Lower Doig Siltstone.
**Includes Clearwater Formation regions that are developed using multi-lateral wells.
MMbbl = million barrels.
10^6 m^3 = million cubic metres.
Bcf = billion cubic feet.
10^9 m^3 = billion cubic metres.
BOE = barrels of oil equivalent using a gas conversion factor of 1/6.
MMBOE = million barrels of oil equivalent.
10^6 m^3 OE = million cubic metres of oil equivalent.

Production and Demand

Figure 7 shows the primary energy production in Alberta by type in the base case and the total primary energy production in the tariff case.

Figure 7 Total primary energy production in Alberta (base case vs. tariff case)



* Geothermal data included in 2020 to 2034.

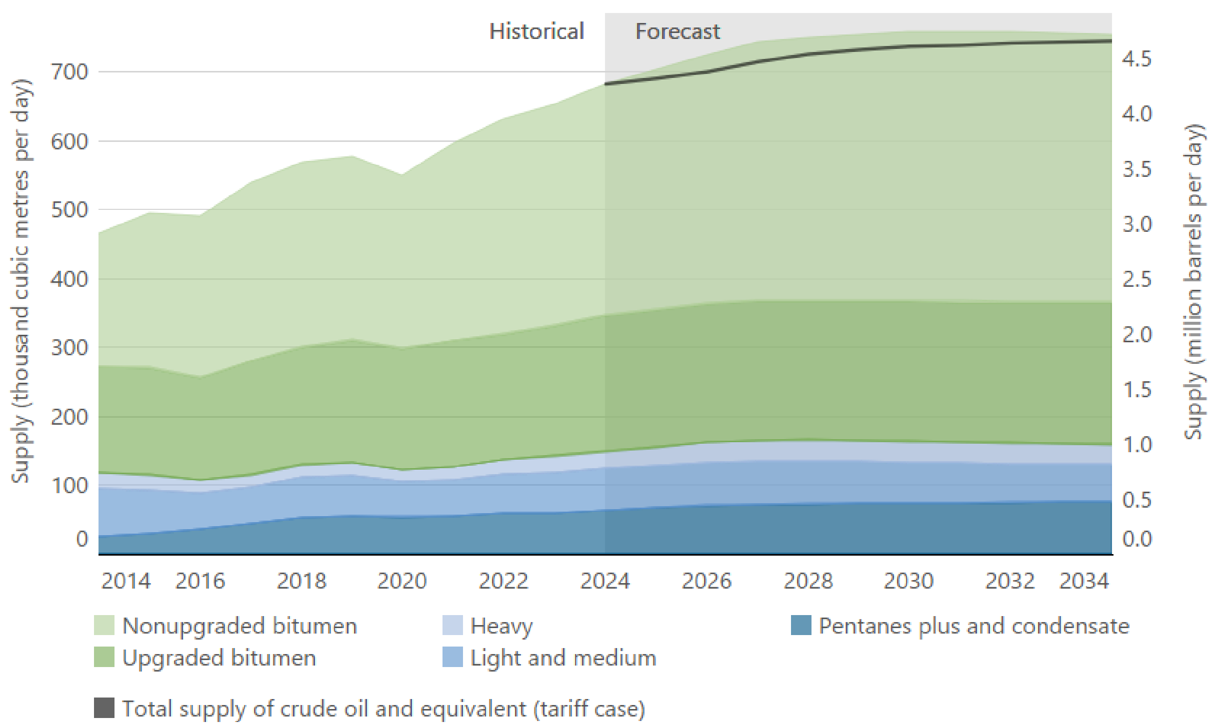
- Total primary energy produced in Alberta increased by 3% in 2024[5] as crude oil and oil sands producers increased production and took advantage of increased pipeline takeaway capacity from the TMX pipeline and favourable oil prices. Natural gas producers continued to focus on drilling in liquid-rich areas with reasonably high prices for liquids.
- Marketable bitumen production, which includes nonupgraded and upgraded bitumen, increased by 4% in 2024, led by optimizations and investment to existing sites, which drove efficiencies and improved productivity, leading to record production from nearly all mines and some in situ projects.
- Crude oil production increased by 3% in 2024 as producers took advantage of relatively high oil prices despite inflation driving up capital and operating costs of production.

[5] 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 marketable natural gas production increased marginally in 2024. Production of shale gas and gas from oil wells increased, while conventional and coalbed methane production remained comparable to 2023. The higher production was driven by increases in production concentrated in the Foothills Front and Northwestern Alberta areas.
- In 2024, Alberta produced an estimated 15 470 petajoules (PJ) of energy from all sources or 6.9 million bbl/d of light-medium quality crude oil equivalent (10^6 BOE/d).
- Under the base case, Alberta is projected to produce 16 969 PJ (7.6 10^6 BOE/d) of energy from all sources in 2034. Under the tariff case, Alberta is projected to produce 16 723 PJ (7.5 10^6 BOE/d) of energy from all sources in 2034, 2% lower than the base case.
- Upgraded and nonupgraded bitumen production accounted for 52% of total primary energy production in 2024.
- In 2024, based on energy content, natural gas liquids production was about 40% higher than crude oil production. This trend is expected to grow over the forecast period in the base case.
- Total natural gas liquids production increased by 6% in 2024, driven mainly by increased pentanes plus and propane production.

Figure 8 shows the Alberta supply of crude oil and equivalent in the base case and the total supply in the tariff case.

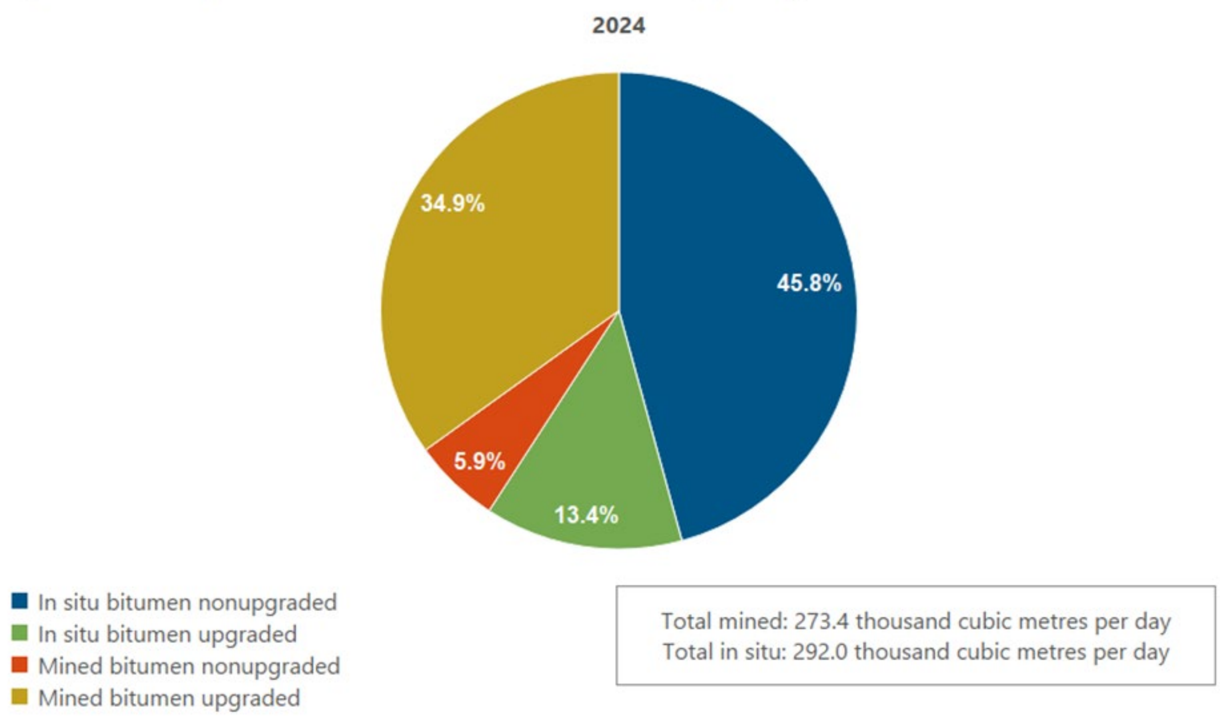
Figure 8 Alberta supply of crude oil and equivalent (base case vs. tariff case)



- Alberta's production of crude oil and equivalent increased by 5% in 2024, reaching 4.3 10^6 bbl/d. The increase is primarily driven by nonupgraded bitumen, upgraded bitumen, crude oil, and pentanes plus.
- Under the base case, crude oil and equivalent production is expected to grow throughout the forecast period, reaching 4.7 10^6 bbl/d by 2034, primarily driven by increased upgraded and nonupgraded bitumen production. Under the tariff case, crude oil and equivalent production is expected to reach 4.7 10^6 bbl/d by 2034.
- Crude oil production increased to 0.5 10^6 bbl/d in 2024 and is projected to continue growing until 2027 in the base case. However, from 2028 to 2034, it would gradually decline as new wells placed on production may be insufficient to offset the decline in existing production.
- Under the base case, production of pentanes plus is forecast to grow from 0.4 10^6 bbl/d in 2024 to 0.5 10^6 bbl/d by 2034.

Figure 9 shows the percentage of bitumen upgraded in Alberta.

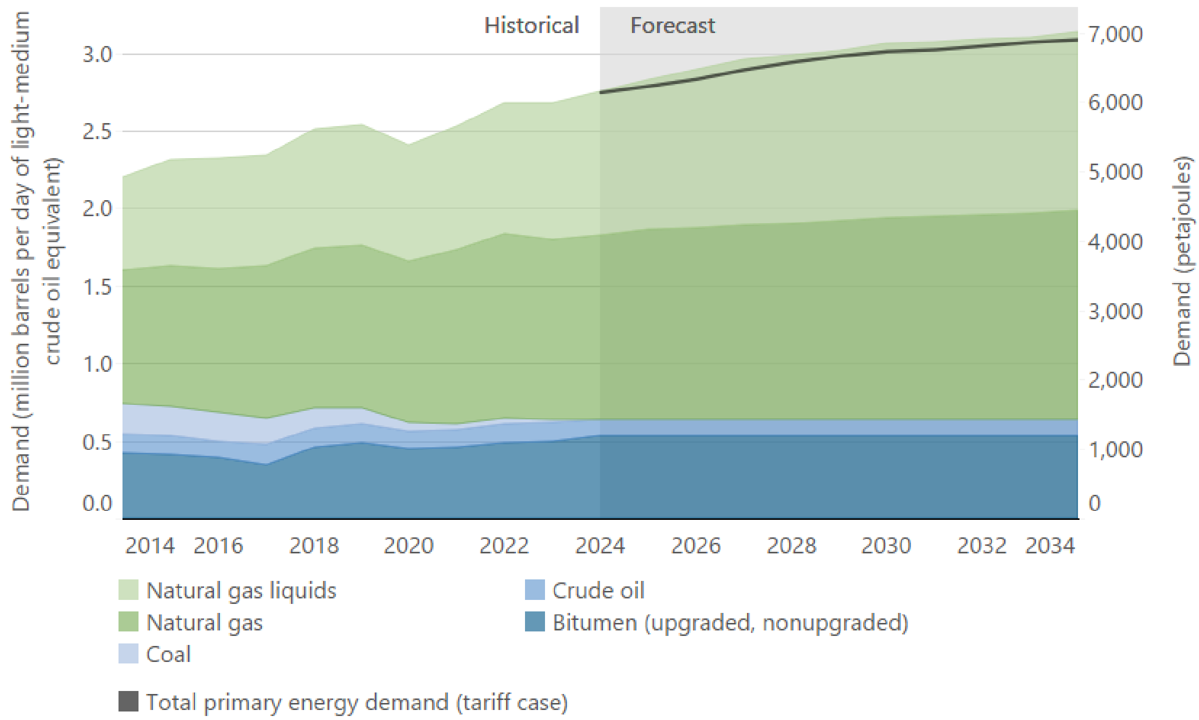
Figure 9 Percentage of mined and in situ bitumen sent for upgrading in Alberta



- An estimated 48% of produced raw bitumen was upgraded in Alberta in 2024. By 2034, only about 44% of raw bitumen is projected to be upgraded in Alberta, as the growth in raw bitumen production is expected to outpace upgrading capacity additions.
- Upgraded bitumen output increased by 4.5% in 2024, across all upgraders due to higher utilization.

Figure 10 shows the primary energy demand in Alberta by type in the base case and the total demand in the tariff case.

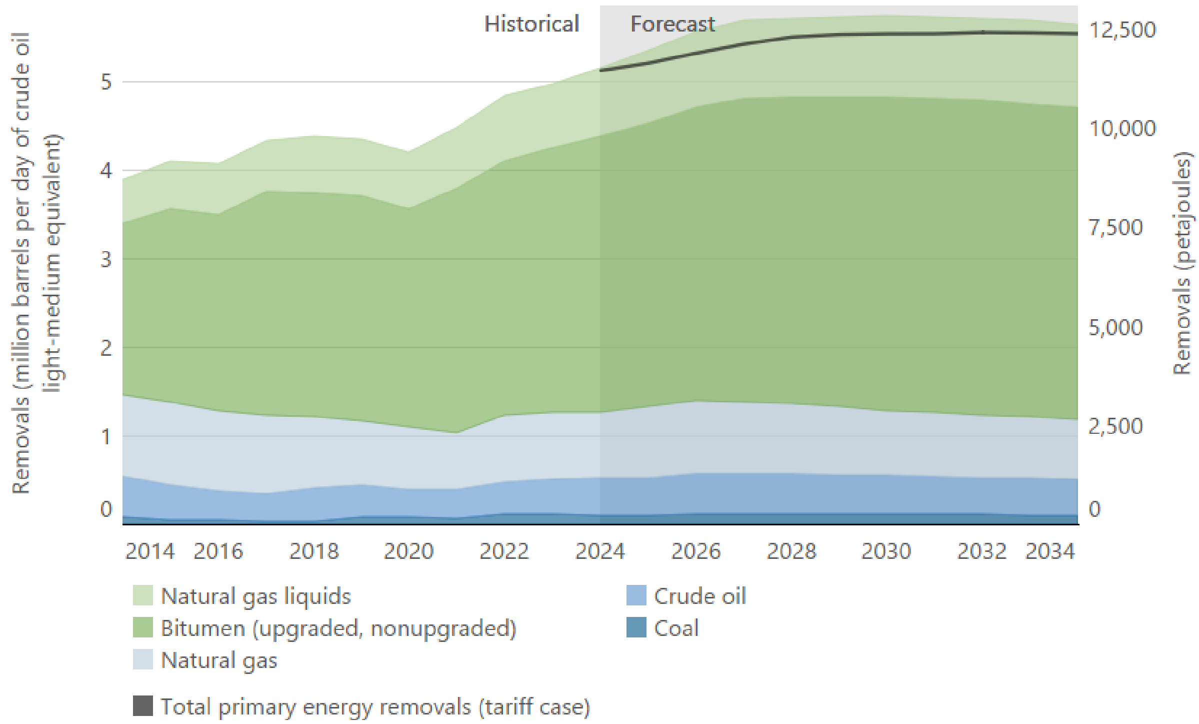
Figure 10 Primary energy demand in Alberta (base case vs. tariff case)



- Alberta's total primary energy demand in 2024 was 6146 PJ (2.8 10^6 BOE/d). Under the base case, Alberta's demand is projected to increase to about 7007 PJ (3.1 10^6 BOE/d) by 2034. This increase is attributed to strengthening demand for pentanes plus as a diluent in bitumen blending. Increasing demand for natural gas was driven by power generation and oil sands in situ operations.
- Under the tariff case, Alberta demand is projected to reach 6907 PJ (3.1 10^6 BOE/d) by 2034, 1% lower than the base case.
- Federal and provincial government policies targeting the reduction of carbon dioxide emissions drove the demand for subbituminous coal in Alberta to nearly zero, as all coal-fired power plants were phased out in 2024.

Figure 11 shows the primary energy removal of energy types from Alberta in the base case and the total removals in the tariff case.

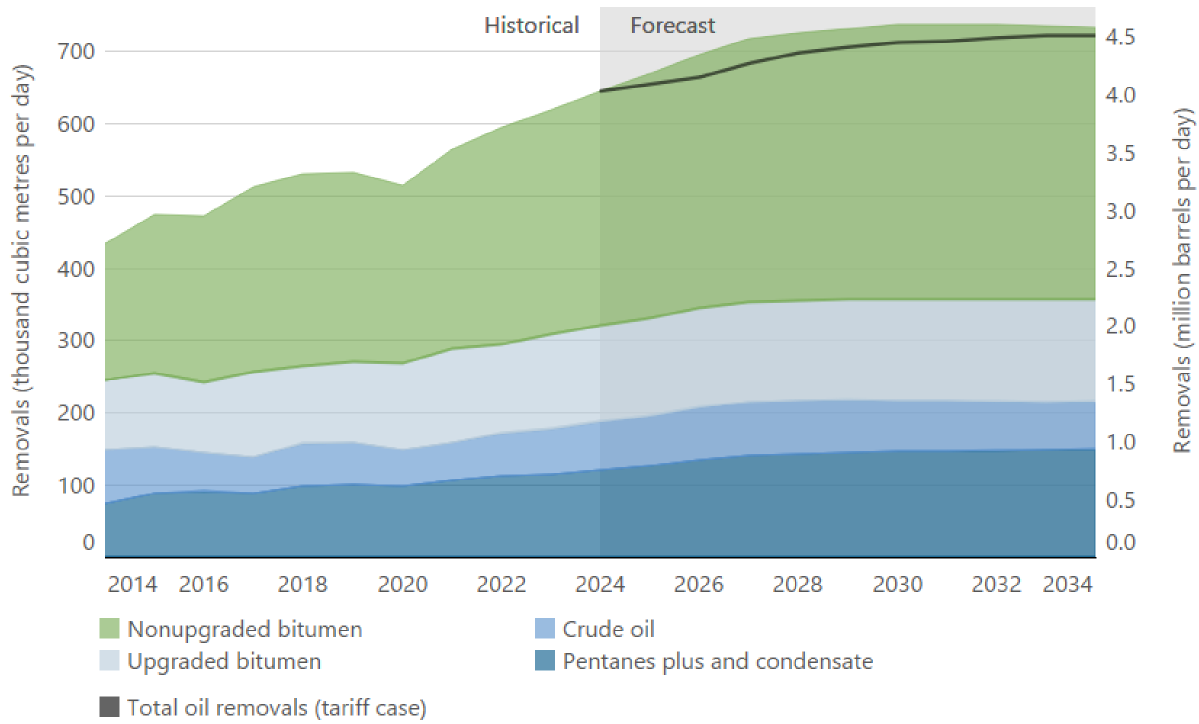
Figure 11 Primary energy removals from Alberta (base case vs. tariff case)



- Primary energy removals from Alberta increased by 3% in 2024. Relatively high prices resulted in increased production output for crude oil, upgraded bitumen, and nonupgraded bitumen. The start-up of the TMX pipeline enabled increased energy removals.
- Total primary energy removals from the province in 2024 were estimated at 11 462 PJ (5.1 10^6 BOE/d), with oil (bitumen and crude oil) and natural gas liquids representing 84% of the primary energy removals for the year.
- Under the base case, removals from the province are projected to reach 12 614 PJ (5.6 10^6 BOE/d) by 2034, with bitumen and crude oil representing a growing share of primary energy removals. Under the tariff case, removals are projected to reach 12 391 PJ (5.6 10^6 BOE/d) by 2034, 2% lower than the base case.
- Under the base case, natural gas removals from Alberta are projected to grow in the short term and decline starting in 2027 and continue to decline to the end of the forecast period. This decline in removals will occur as demand growth is forecast to outpace production growth.
- Removals of marketable bituminous coal from Alberta decreased by 7% in 2024. as production decreased at the Grande Cache, Coal Valley, and Vista coal mines.

Figure 12 shows the removal of oil from Alberta by type in the base case and the total removal in the tariff case.

Figure 12 Total oil removals from Alberta (base case vs. tariff case)

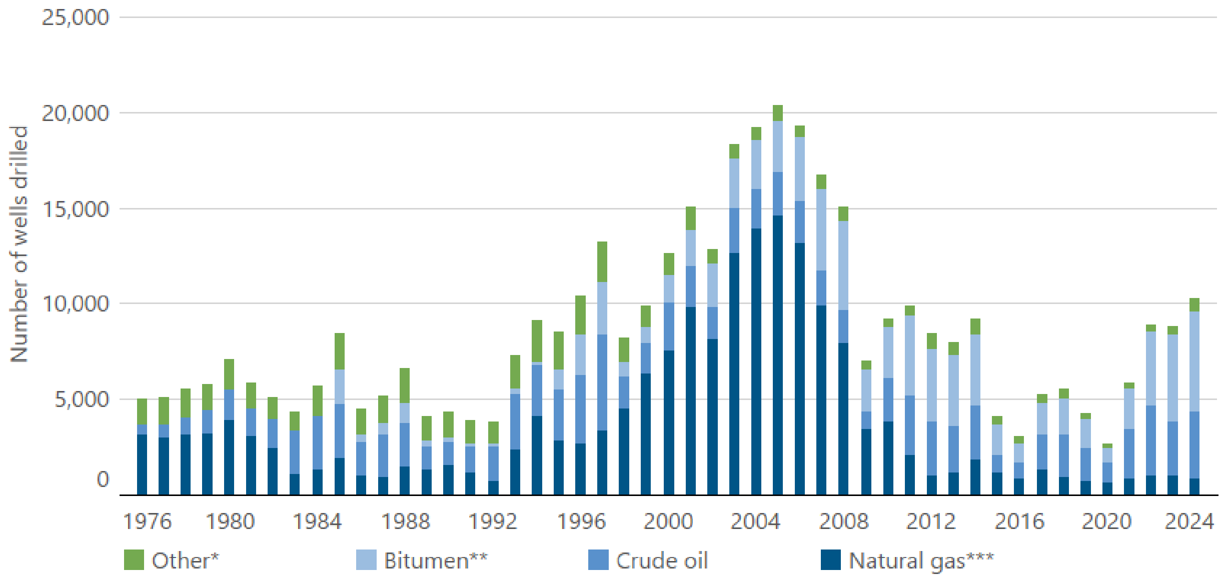


- In 2024, removals of crude oil, pentanes plus, upgraded bitumen, and nonupgraded bitumen were estimated at 640.5 10^3 m^3/d or 4.0 10^6 bbl/d—about 4% higher than in 2023.
- Under the base case, by 2034, about 728.1 10^3 m^3/d (4.6 10^6 bbl/d) of crude oil, pentanes plus, upgraded bitumen, and nonupgraded bitumen are forecast for removal from the province. This projection assumes sufficient removal capacity would be available because of pipeline expansion, optimization, and crude-by-rail transportation. Under the tariff case, total oil removals are projected to reach 717.2 10^3 m^3/d (4.5 10^6 bbl/d) by 2034, 2% lower than the base case.

Drilling Activity

Figure 13 shows that total drilling increased by 16% in 2024 (natural gas drilling decreased by 10%, crude oil drilling increased by 22%, and oil sands drilling increased by 16%). This is the highest drilling activity over the past sixteen years.

Figure 13 Historical drilling activity in Alberta



Note: The number of wells drilled include legs and recompletions.
* Includes unsuccessful, service, and suspended wells.
** Includes producing and evaluation wells.
*** Includes coalbed methane wells.

1 Reserves

In 2024, the Alberta Energy Regulator (AER) procured the services of McDaniel and Associates Consultants Ltd. (McDaniel) to evaluate the reserves and resources of Alberta using industry-accepted methods published in the *Canadian Oil and Gas Evaluation Handbook* (*COGEH*) for conventional, unconventional and oil sands formations. The new assessments will differ by including additional formations and applying current best practices and better data. Collaboration with McDaniel has presented an opportunity to improve our understanding of the province's resource endowment and to refine our approach for assessments in future years. Unconventional reserves and resources in the Montney Formation, Duvernay Formation, Spirit River Formation, and regions of the Clearwater Formation developed with multilateral well designs are currently available (Table 1). The online web version of the *Alberta Energy Outlook* will be updated as more results are delivered, and a final report prepared by McDaniel will be published as part of the *Alberta Energy Outlook* later in 2025.

The updated natural gas assessments for the Montney, Duvernay, and Spirit River Formations are significant not only for Alberta but also for Canada. Based on the Government of Alberta press release in March 2025, with new estimates for these formations, Canada has more than doubled its gas reserves, moving it from number 15 to number 9 globally in reserves. The use of multilateral wells for development of heavy oil in the Clearwater Formation resulted in notable production growth over the last five years and contributed further to the provincial reserves.

1.1 Montney Formation

The Triassic Montney Formation contains both conventional and unconventional resource plays. To be consistent with the stratigraphic nomenclature used in British Columbia, the Montney Formation in Alberta was evaluated together with the Lower Doig Siltstone (Table 1). Unconventional gas reserves in the Montney Formation were assessed as 64.5 trillion cubic feet (Tcf), oil as 0.41 billion barrels (Bbbl), and condensate as 2.9 Bbbl. Total reserves for the unconventional portion of the Montney Formation were assessed as 14.1 billion barrels of oil equivalent (BOE). Assessment of conventional reserves in the Montney Formation by McDaniel will be released later in 2025.

1.2 Duvernay Formation

The Devonian Duvernay Formation contains only unconventional resources (Table 1). Gas reserves in the Duvernay Formation were assessed as 17.7 Tcf, oil as 1.74 Bbbl, and condensate as 0.89 Bbbl. Total reserves for the Duvernay Formation were assessed as 5.57 billion BOE.

1.3 Spirit River Formation

The Cretaceous Spirit River Formation contains significant natural gas resources from its Wilrich, Falher, and Notikewan Members (Table 1). Preliminary natural gas reserves were assessed as 41.7 Tcf, the best estimate at the time of writing.

1.4 Clearwater Formation

The Cretaceous Clearwater Formation is a major target for thermal oil sands development in the Cold Lake region of Alberta. New technology has facilitated drilling novel multilateral well designs, while significant production of nonthermal heavy oil from the Clearwater Formation has also taken place since 2017. Between 2017 and 2025, multilateral production grew from ~30 to 230 thousand barrels per day (10^3 bbl/d), with McDaniel concluding it is Canada's fastest-growing oil resource play (Table 1). Oil reserves at the time of this writing are estimated at 1.61 Bbbl and gas reserves at 1.16 Tcf.

Table 1 Remaining proved + probable reserves volumes (as of December 31, 2023)

Category	Oil		Condensate		Gas		Oil equivalent	
	MMbbl	10^6 m^3	MMbbl	10^6 m^3	Bcf	10^9 m^3	MMBOE	10^6 m^3 OE
Duvernay Formation								
2P Producing & Undeveloped Reserves	1,735	276	890	141	17,676	498	5,571	885
Montney Formation*								
2P Producing & Undeveloped Reserves	409	65	2,892	460	64,502	1,817	14,052	2,234
Spirit River Formation								
2P Producing & Undeveloped Reserves	-	-	-	-	41,746	1,176	6,958	1,106
Clearwater Formation**								
2P Producing & Undeveloped Reserves	1,614	257	-	-	1,164	33	1,808	287

Any discrepancy is due to rounding.
Note: 2P – best estimate (proved + probable) of reserves.
*Includes unconventional regions of the Montney Formation & Lower Doig Siltstone.
**Only includes Clearwater Formation regions that are developed using multi-lateral wells.
MMbbl = million barrels.
10^6 m^3 = million cubic metres.
Bcf = billion cubic feet.
10^9 m^3 = billion cubic metres.
BOE = barrels of oil equivalent using a gas conversion factor of 1/6.
MMBOE = million barrels of oil equivalent.
10^6 m^3 OE = million cubic metres of oil equivalent.

2 Prices and Capital Expenditure

2.1 Highlights of 2024

2.1.1 Oil Prices

West Texas Intermediate (WTI): The price of WTI decreased by 2.4% in 2024 due to concerns about weak global oil demand growth, while the global oil supply was relatively stable.

Western Canada Select (WCS): The price of WCS rose by 3.4% in 2024. Compared with 2023, the price differential between WCS and WTI narrowed to US$15 per barrel (bbl) due to the start-up of the Trans Mountain pipeline expansion in May 2024.

Price differential: The differential between WTI and WCS declined from US$18.65/bbl in 2023 to US$14.73/bbl in 2024.

Table S1.1 shows historical and base case forecast prices for crude oil.

Table S1.1 Crude oil prices

	2023	2024	2025	2026	2034
West Texas Intermediate (US$/bbl)[a]	77.62	75.72	66.00	68.00	76.50
Western Canadian Select (US$/bbl)[a]	58.97	60.99	55.00	56.00	63.50

[a] US$/bbl = U.S. dollars per barrel.
Historical values from the Government of Alberta, U.S. Energy Information Administration, and MarketWatch.
Forecasts have been rounded.

2.1.2 Gas Prices

Henry Hub: The primary price benchmark for U.S. natural gas decreased by 9.7% in 2024, averaging US$2.41 per million British thermal units (MMBtu). The Henry Hub price decrease was attributed to elevated North American inventories and mild winter weather, reducing residential and commercial natural gas demand.

AECO-C: The AECO-C price, the benchmark for Western Canadian natural gas, decreased 47% from 2023 to an average of Cdn$1.45 per gigajoule (GJ) in 2024. The price decrease was primarily attributed to regional oversupply and warmer-than-expected winter weather, leading to a significant excess inventory.

Price differential: The price differential between Henry Hub and AECO-C widened to $1.29/MMBtu in 2024, up from US$0.52/MMBtu in 2023.

Table S1.2 shows the historical and forecast prices for natural gas.

Table S1.2 Natural gas prices

	2023	2024	2025	2026	2034
Henry Hub price (US$/MMBtu)[a]	2.67	2.41	3.80	3.90	4.59
AECO-C price (Cdn$/GJ)[b]	2.74	1.45	2.71	3.82	4.37

[a] US$/MMBtu = U.S. dollars per million British thermal units.
[b] Cdn$/GJ = Canadian dollars per gigajoule.
Historical values from the *Canadian Gas Price Reporter,* U.S. Energy Information Administration, MarketWatch, and Intercontinental Exchange.

2.1.3 Total Capital Expenditures

Total capital expenditures remained steady in 2024, increasing slightly to Cdn$30.9 billion.

Despite the decrease in energy prices in 2024, sS. demand for Alberta's oil increased by 2%, reaching 1.3 billion barrels.[6] The increased demand triggered strong growth in conventional and oil sands drilling and mining supporting investment levels. Capital expenditures are projected to remain below the 2014 peak over the 10-year forecast period.

2.1.4 Exchange Rate

The U.S. and Canadian dollar exchange rate averaged US$0.73 in 2024 compared with US$0.74 in 2023.

2.2 Tariff Scenarios

Because of significant uncertainty, particularly regarding U.S. tariff policies, this year's report examines two scenarios: a short-term tariff uncertainty scenario (base case) and a one-year tariff scenario (tariff case). The primary difference between these scenarios lies in their tariff assumptions.

- **Base case**: This scenario assumes business as usual and no tariffs. However, the U.S. tariff threats on energy products (oil and gas) persist throughout the first half of 2025 but are ultimately averted through diplomatic negotiations by midyear. Consequently, energy supply and demand are minimally affected.
- **Tariff case**: This scenario assumes a 10% U.S. tariff on energy products (oil and gas) and 25% tariffs on other Canadian goods imposed in the first half of 2025 despite diplomatic efforts. This scenario includes subsequent U.S. and Canadian retaliatory tariffs, other nontariff measures,[7] and additional U.S. tariffs on other trading partners. All tariffs and nontariff measures between Canada and the United States persist until the end of the first quarter of 2026 before mostly being phased out as the review or renegotiation of the

[6] Statistics Canada. Table 25-10-0063-01 Supply and disposition of crude oil and equivalent

[7] Nontariff measures can include quotas or restrictions on imported goods (i.e., liquor), export taxes on electricity, and changes in consumer and business behaviour (i.e., buying Canadian).

Canada-United States-Mexico Agreement. It is expected tariffs will have some long-term effects and structural changes to the global economy (changes in trade and investment flows).

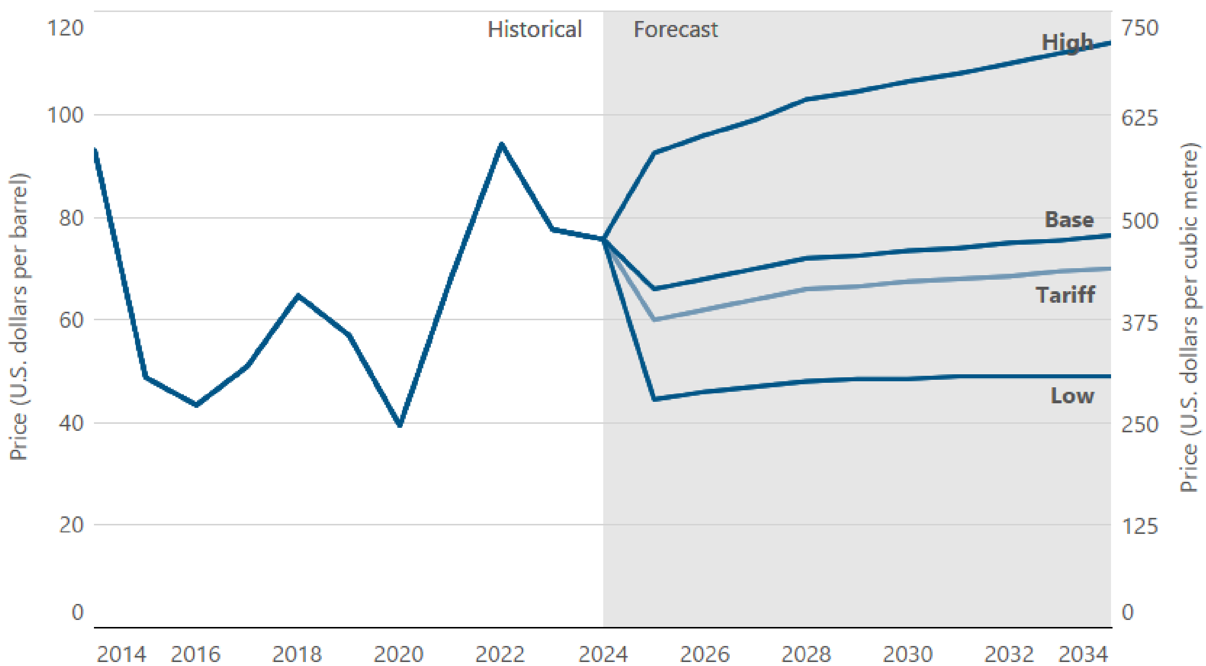
These tariff assumptions affect prices, costs, commodity profitability, investment, supply and demand, project risk factors, and commercial start dates (where applicable) for most chapters of the report, including comparisons of the outcomes of these scenarios.

2.3 Crude Oil Price

2.3.1 West Texas Intermediate Price

Figure S1.1 shows historical and forecast prices for WTI.

Figure S1.1 West Texas Intermediate crude oil price (base case vs. tariff case)



Historical values sourced from U.S. Energy Information Administration and MarketWatch.

2.3.1.1 Summary

The average annual price of WTI in 2024 was US$75.72/bbl, a decrease of 2.4% from 2023.

In the base case, the WTI price is forecast to decrease to US$66.00/bbl in 2025, improving to US$78.00/bbl in 2026 and reaching US$76.50 in 2034.

Under the tariff case, the WTI price is expected to fall to US$60.00/bbl in 2025 as tariffs weigh on international trade and slow global oil demand growth, improving to US$62.00/bbl in 2026, reaching US$70.00/bbl by 2034.

The low-price case assumes a drop in demand for transportation fuels due to a global economic recession and strong supply growth with WTI to average US$44.50/bbl in 2025, reaching US$49.00/bbl by 2034.

The high-price case considers a rapid economic expansion, higher than anticipated global demand, and constrained supply, resulting in an average price of US$92.50/bbl in 2025, reaching US$114.00/bbl in 2034.

2.3.1.2 In 2024

U.S. production: The price of WTI decreased in 2024 mostly due to concerns about weak oil demand growth in China, while global oil supply was relatively stable. U.S. oil production increased from 12.9 million barrels per day (bbl/d) in 2023 to a record 13.2 million bbl/d in 2024. Productivity continued to improve as U.S. drilling activity held relatively steady throughout the year.

OPEC+ supply management: To keep global oil prices stable, the Organization of the Petroleum Exporting Countries and its allied non-member countries (collectively referred to as OPEC+) reduced crude oil supply by 1.4 million bbl/d in 2024, according to the U.S. Energy Information Agency (U.S. EIA). This situation was achieved by increased member compliance with production targets and extending production cuts by member states plus voluntary cuts by Saudi Arabia and Russia, which have been in place since the COVID-19 pandemic and will end in 2025.

2.3.1.3 Base Case Forecast for 2025 to 2034

Global crude oil prices are expected to decline in 2025. The uncertainty surrounding U.S. trade policy and the threat of U.S. tariffs against Canada and other countries is expected to weigh on crude oil demand throughout the first half of 2025. The decision by OPEC+ to increase their crude oil supply starting in April 2025 further weighs on global oil prices, including the WTI price.

Other factors influencing the near-term WTI price forecast include weak oil demand growth from China, which is partially offset by rising demand from India, fears of a possible recession, and non-OPEC+ production growth, including the United States, Canada, Brazil, and Guyana. Additionally, geopolitical tensions may ease in the Middle East and with Ukraine and Russia;

however, more stringent U.S. trade sanctions on Russia, Iran, and Venezuela could restrict supply.

Under this scenario, global demand is expected to improve in 2026 as trade tensions ease, global economic growth accelerates, and demand for transportation fuels in India rises. However, continued crude oil production growth from non-OPEC+ countries is expected to limit price gains. By 2027, demand for crude oil is anticipated to increase, providing a modest rise in the WTI price.

The long-term forecast largely depends on the demand for petroleum liquid fuels. Despite advances in environmental policies, there is still uncertainty about the adoption rate of renewable energy and electric vehicles. Growing demand for petroleum-sourced feedstock in the petrochemical sector, particularly in developing economies, may offset the slowing demand for oil-derived transport fuels.

U.S. oil production: U.S. production is projected to continue rising to new heights in 2025 and 2026, although the pace of growth is expected to be slower than in past years. Most of the recent growth in U.S. production has come from shale and tight formations. Wells in these formations have steep decline curves, requiring significant increases in new drilling to maintain production levels. However, according to the U.S. EIA, advances in horizontal drilling and hydraulic fracturing techniques have increased well productivity. These advancements enable U.S. producers to extract more crude oil from each new well drilled while maintaining production for longer from older wells.

Geopolitical tensions: Geopolitical tensions remain a key uncertainty in the crude oil market. While the Israel-Hamas conflict may be resolved in 2025, the ongoing war in Ukraine may disrupt the crude oil supply from Russia. New U.S. sanctions targeting Iranian and Venezuela crude oil exports may result in lower supply in the market. Furthermore, potential U.S. import tariffs on a range of goods from oil and gas to steel and aluminum, and even consumer goods and retaliatory counter tariffs by affected exporting countries have led to greater volatility in the near-term WTI price.

2.3.1.4 One-Year Tariff Scenario (Tariff Case)

Despite diplomatic efforts, the United States has imposed tariffs on many countries, including Canada, Mexico, China, and the European Union, sparking a broad-ranging trade war starting in April 2025 and lasting for one year. Back-and-forth tariff retaliation is expected, resulting in disrupted trade flows and dampened global oil demand growth, leading to a 21% year-over-year decline in the WTI price to US$60.00/bbl in 2025, 9.1% below the base case. It is expected to modestly rebound to US$62.00/bbl in 2026 as tariffs ease; however, the gap between the base case and the tariff case is expected to persist throughout the forecast period due to long-term structural changes in global oil demand, supply chains, and international trade. By 2034, the WTI price is anticipated to be US$70.00/bbl, 8.5% below the base case. All other crude oil supply and demand assumptions are unchanged compared with the base case price forecast.

2.3.1.5 Low- and High-Price Cases

The low- and high-price cases are estimated using a 95% confidence interval. The following factors affect the WTI price cases:

Low-price case:

- Global oil demand declines more than expected due to a potential global economic recession.
- OPEC+ production greatly exceeds the targets, increasing the global crude oil supply and inventories.
- U.S. shale production grows more than expected throughout the forecast period.
- Geopolitical tensions and conflicts subside allowing the global oil supply to grow.

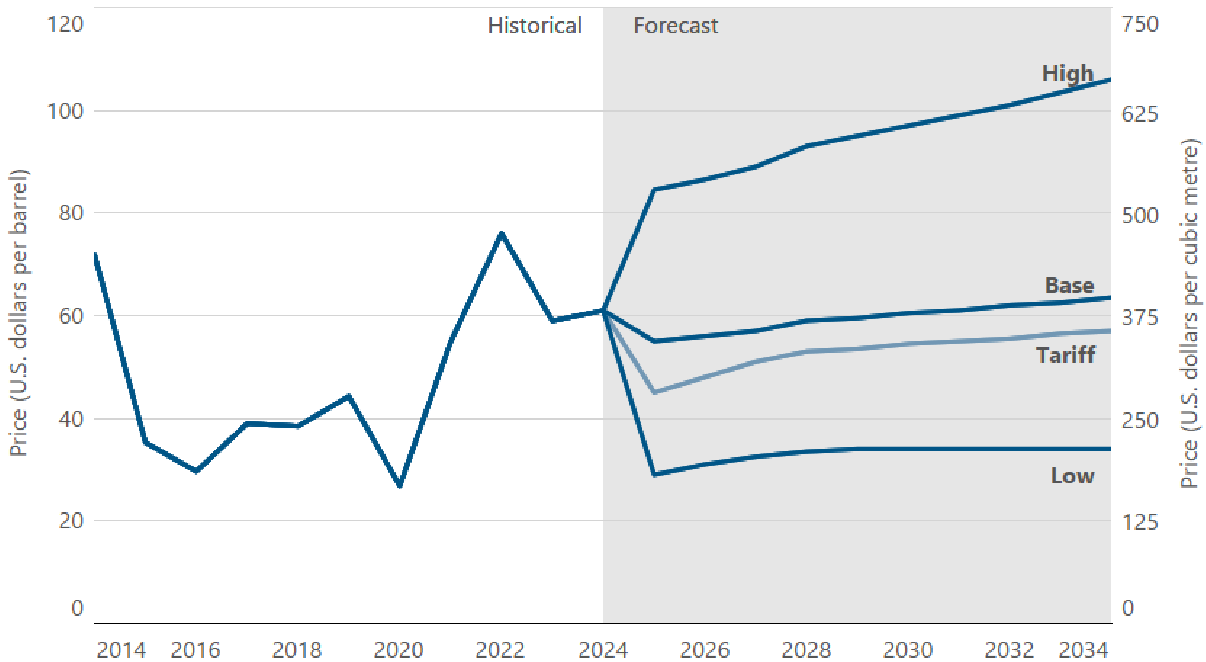
High-price case:

- Global oil demand rises more than expected due to accelerating economic growth.
- OPEC+ cuts production more than expected, reducing the global crude oil supply and inventories.
- U.S. shale production grows less than expected throughout the forecast period.
- Geopolitical tensions and conflicts continue to disrupt the global oil supply.

2.3.2 Western Canadian Select Price

Figure S1.2 shows historical and forecast prices for WCS.

Figure S1.2 Western Canadian Select crude oil price (base case vs. tariff case)



Historical values sourced from the Government of Alberta.

2.3.2.1 Summary

The average annual price of WCS in 2024 was US$60.99/bbl, an increase of 3.4% from 2023.

In the base case, the WCS price is forecast to be around US$55.00/bbl in 2025, increasing to US$56.00/bbl in 2026, reaching US$63.50/bbl in 2034.

The tariff case, low-, and high-price cases for WCS align with the WTI forecast assumptions.

Under the tariff case, the WCS price is expected to fall to US$45.00/bbl in 2025, improving to US$48.00/bbl in 2026 and reaching US$57.00/bbl in 2034.

The low-price case forecast for WCS is US$29.00/bbl in 2025, reaching US$34.00/bbl in 2034.

The high-price case forecast for WCS is US$84.50/bbl in 2025, reaching US$106.00/bbl in 2034.

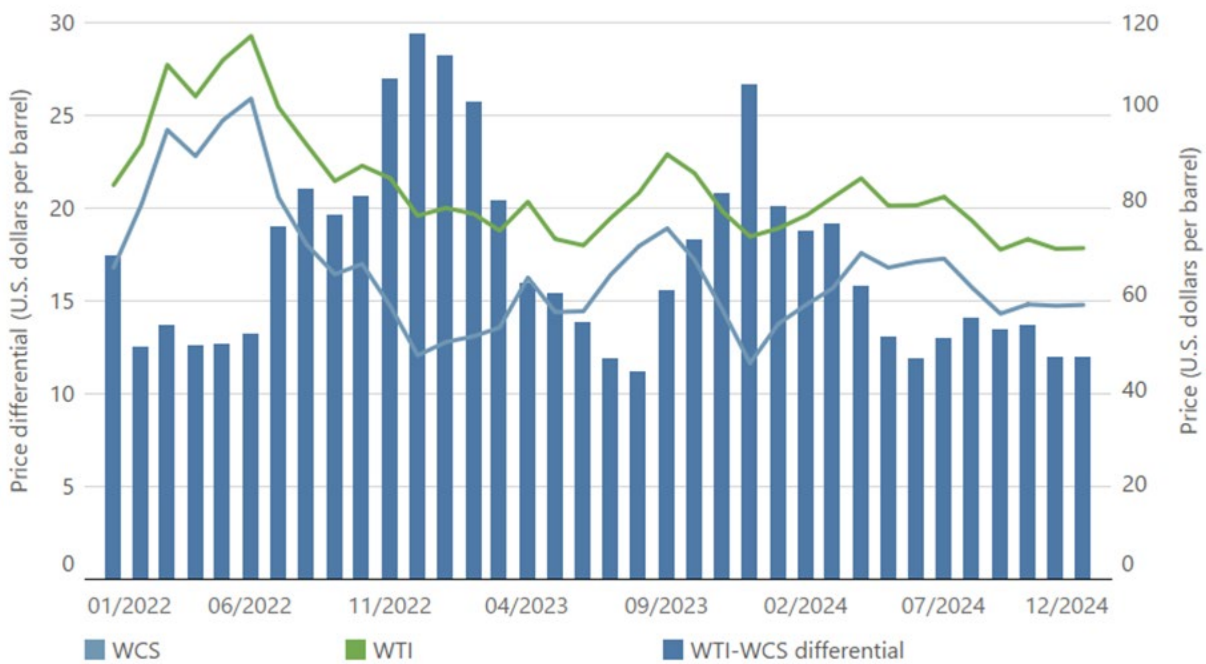
The WCS price is expected to follow the WTI trend but will remain lower due to quality differences and transportation costs.

2.3.2.2 In 2024

Price differential: The WTI-WCS price differential narrowed from US$18.65/bbl in 2023 to US$14.73/bbl in 2024. This decline was attributed to the commissioning of the Trans Mountain pipeline expansion in May 2024, which provided additional export capacity for crude oil on the Canadian West Coast.

Figure S1.1 shows the historical price differential for WCS relative to WTI.

Figure S1.3 Canadian oil price differential



Historical values from the Government of Alberta, U.S. Energy Information Administration, and MarketWatch.

2.4 Natural Gas Prices

2.4.1 Highlights for 2025 to 2034 – Short-Term Uncertainty Scenario (Base Case)

Despite the U.S. tariff uncertainty, North American natural gas prices are expected to rebound in 2025 from relatively low levels experienced in 2024. This increase is driven by colder winter weather, low North American inventories, and LNG capacity expansions in both the United States and Canada.

Henry Hub: The Henry Hub price is forecast to rise to US$3.80/MMBtu in 2025, reaching US$4.59/MMBtu by 2034. Long-term demand is anticipated to increase, primarily driven by growth in U.S. domestic demand and exports.

AECO-C: The AECO-C price is forecast to increase to Cdn$2.71/GJ in 2025 and reach Cdn$4.37/GJ by 2034.

Price differential: The price differential between AECO-C and Henry Hub reflects transportation costs, regional supply and demand balances, and infrastructure constraints. The AECO-C and Henry Hub price differential is anticipated to average around US$1.80/MMBtu in 2025 and narrow to US$1.00/MMBtu in 2026, remaining steady for the remainder of the forecast period.

2.4.2 Highlights for 2025 to 2034 – One-Year Tariff Scenario (Tariff Case)

Despite diplomatic efforts, Canada is unable to avoid the U.S. tariffs. We have assumed a 10% tariff on Canadian energy products and a 25% tariff on other goods starting in the first half of 2025. The United States has implemented additional tariffs on China, the European Union, and other major trading partners. Canada and other U.S. trading partners will respond with tariffs on the United States. Under this scenario, the tariffs between Canada and the United States are assumed to remain in place for 12 months before mostly being phased out in 2026. All other natural gas supply and demand assumptions are unchanged compared with the base case price forecast.

Henry Hub: The Henry Hub price under the tariff case is forecast to rise to US$3.20/MMBtu in 2025, reaching US$4.37/MMBtu by 2034.

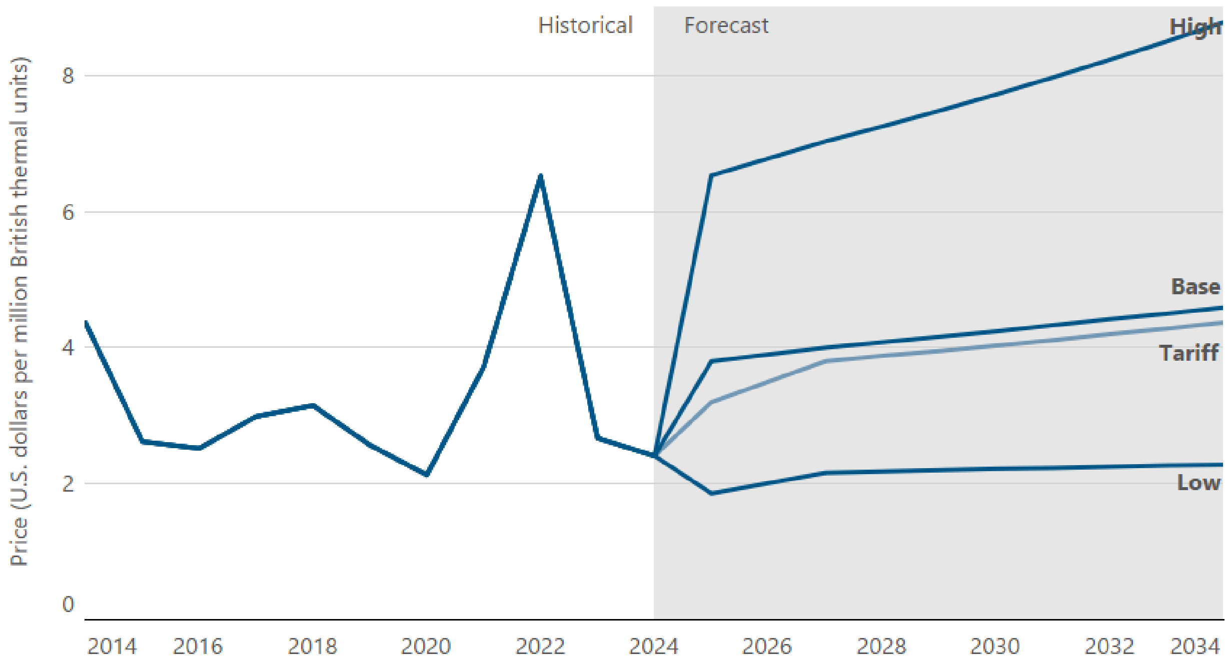
AECO-C: The AECO-C price under the tariff case is forecast to increase to Cdn$1.56/GJ in 2025, reaching Cdn$4.09/GJ by 2034.

Price differential: The AECO-C and Henry Hub price differential is anticipated to widen under the tariff case to US$2.10/MMBtu in 2025. As tariffs ease in 2026, the differential is expected to narrow to US$1.20/MMBtu in 2026 and stabilize at US$1.00/MMBtu over the remaining forecast period.

2.4.3 Henry Hub Price

Figure S1.4 shows the historical and forecast Henry Hub natural gas price.

Figure S1.4 Henry Hub natural gas price (base case vs. tariff case)



Historical values from U.S. Energy Information Administration and MarketWatch.

2.4.3.1 Summary

The Henry Hub price averaged US$2.41 MMBtu in 2024, marking a decrease of 9.7% from 2023.

In the base case, the Henry Hub price is forecast to rebound to US$3.80/MMBtu in 2025, then increase to US$3.90/MMBtu in 2026, reaching US$4.59/MMBtu by 2034.

Under the tariff case, the Henry Hub price is expected to average US$3.20/MMBtu in 2025, reaching US$4.37/MMBtu by 2034.

Based on the low- and high-price cases, prices are projected to range from US$2.28/MMBtu to US$8.78/MMBtu by 2034.

2.4.3.2 In 2024

U.S. production: U.S. total natural gas production remained relatively steady at an estimated 113.2 billion cubic feet per day (Bcf/d) (3.2 billion cubic metres per day [m^3/d]), according to the U.S. Energy Information Administration, representing a 0.3% increase compared with 2023.

Dry natural gas production, similar to the AER's definition of marketable gas, eased 0.3% from 2023 due to some gas producers curtailing production in response to lower prices. However, this slight decline was offset by a 7.7% growth in gas production associated with oil wells, also known as associated gas.

U.S. demand and exports: Natural gas consumption in the United States rose by 1.1% in 2024 to 90.4 Bcf/d (2.5 billion m^3/d), driven by increased demand from electrical power generation. U.S. natural gas exports increased by 1.0%, with higher liquefied natural gas (LNG) exports and natural gas pipeline exports to Canada and Mexico.

2.4.3.3 Base Case Forecast for 2025 to 2034

U.S. production and demand: The Henry Hub price is anticipated to modestly rebound in 2025 due to colder winter weather and a decline in inventories. This increase is driven by modest domestic demand growth from residential use and power generation plus LNG capacity expansions (see next section). U.S. natural gas production is expected to rise to meet the growth in demand. In 2026 and 2027, U.S. demand growth is projected to accelerate; however, solid production growth will limit price gains. Associated gas production is expected to rise as oil production increases due to higher forecasted oil prices. From 2028 onwards, natural gas prices are forecast to increase, fuelled by growth in power generation and industrial demand.

U.S. exports and imports: Natural gas exports from the United States are anticipated to rise over the forecast period. U.S. LNG capacity is expected to expand by 46%, with three new LNG plants ramping up production or coming online between December 2024 and January 2027. Plaquemines LNG and Corpus Christi LNG Stage 3 began operations in December 2024, while Golden Pass LNG is expected to come online in mid-2026. From 2027 onwards, U.S. LNG capacity is expected to grow further as the new U.S. administration has lifted the LNG export permit freeze that was put in place in early 2024. Additionally, natural gas pipeline imports from Canada are expected to revert to the decreasing trend, which began in 2008, as U.S. domestic natural gas production rises.

2.4.3.4 One-Year Tariff Scenario (Tariff Case)

Despite diplomatic efforts, the United Staes has imposed tariffs on many countries, including Canada, Mexico, China, and the European Union, sparking a broad-ranging trade war starting in the first half of 2025 and lasting for one year. Back-and-forth tariff retaliation is expected. China has announced its plans to reduce imports of U.S. LNG in response. The resulting trade disruptions will moderate global natural gas demand growth, leading to an average Henry Hub price of US$3.20/MMBtu in 2025, a 16% decline relative to the base case forecast. As tariffs come off in 2026, the Henry Hub price is anticipated to increase to US$3.50/MMBtu, reaching US$4.37/MMBtu by 2034, 4.8% lower than the base case forecast. All other natural gas supply and demand assumptions are unchanged compared with the base case forecast.

2.4.3.5 Low- and High-Price Cases

The low- and high-price cases capture near- and long-term volatility of the Henry Hub price and are estimated using a 95% confidence interval. The following factors were captured in the price cases:

Low-price case:

- North American demand is less than expected due to a potential economic recession.
- U.S. natural gas production growth is faster than expected.
- More associated gas is produced as significantly more oil wells are drilled than expected in the near term.
- LNG capacity grows slower than expected.

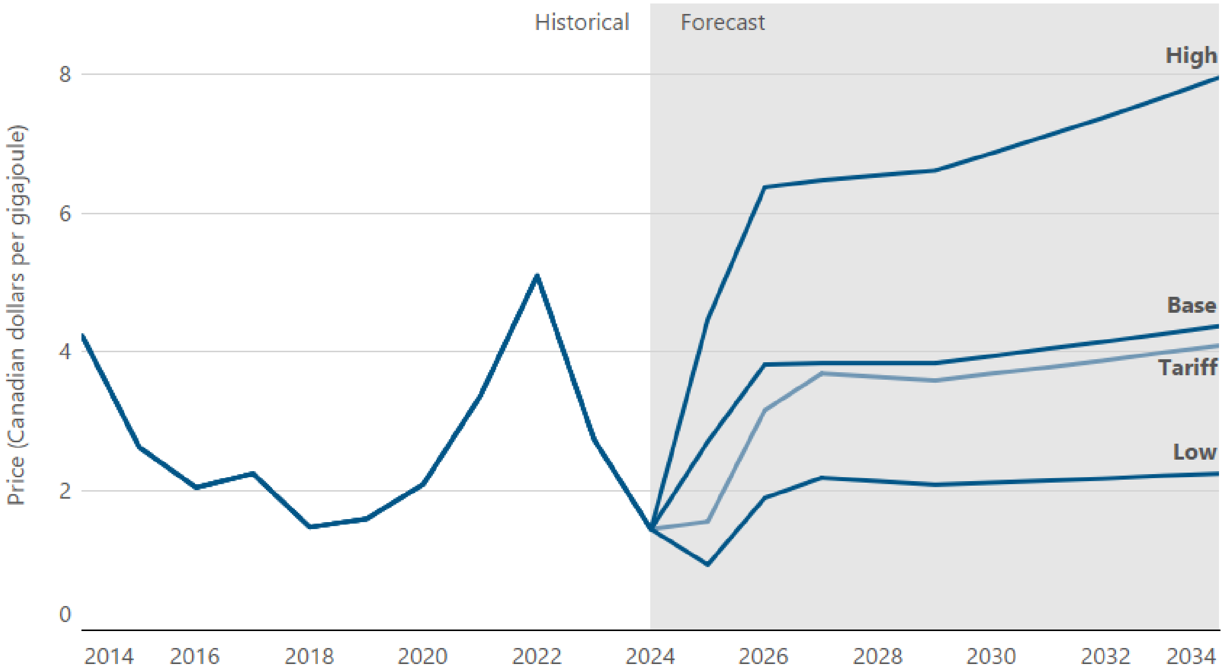
High-price case:

- North American demand rises more than expected due to stronger economic growth.
- U.S. natural gas production growth is slower than expected.
- Less associated gas is produced as significantly fewer oil wells are drilled than expected in the near term.
- Switching from coal to natural gas for power generation and industrial

2.4.4 AECO-C

Figure S1.5 shows the historical and forecast AECO-C natural gas price.

Figure S1.5 AECO-C natural gas price (base case vs. tariff case)



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

2.4.4.1 Summary

The average annual price of AECO-C natural gas was Cdn$1.45 per gigajoule (GJ) in 2024, decreasing by 47% from 2023.

In the base case, the AECO-C price is forecast to rebound to Cdn$2.71/GJ in 2025, rising to Cdn$3.82/GJ in 2026 and slowly increase to Cdn$4.37/GJ by 2034.

The tariff case, low-, and high-price cases for AECO-C align with the Henry Hub forecast assumptions.

Under the tariff case, the AECO-C price is expected to average Cdn$1.56/GJ in 2025, reaching US$4.09/GJ by 2034.

Based on the low- and high-price cases, prices are projected to range from Cdn$2.25/GJ to Cdn$7.95/GJ by 2034.

2.4.4.2 In 2024

The AECO-C price fell more than the Henry Hub price in 2024 due to a combination of factors, including a regional oversupply and warmer-than-expected winter weather, resulting in significant excess inventory and little room for storing additional natural gas. Some natural gas producers in western Canada reported curtailing production and deferring drilling plans due to the low prices. Lower demand from the U.S. also played a role. Consequently, the AECO-C and Henry Hub price differential widened from US$0.52 MMBtu in 2023 to US$1.29/MMBtu.

2.4.4.3 Base Case Forecast for 2025 to 2034

Exports and market access: Natural gas exports from western Canada to the United States decreased in 2024, which were partially offset by higher exports to Eastern Canada. Over the forecast period, exports to the United States will continue to decline due to increased U.S. natural gas production. Western Canada exports to Eastern Canada are expected to remain steady because additional U.S. natural gas will be directed towards supplying American liquefied natural gas (LNG) export expansions and rising domestic demand, leaving little to no gas available to export to Eastern Canada. British Columbia's LNG exports are expected to increase market access for Canadian natural gas sometime in 2025 and beyond.

Domestic demand: Alberta’s demand for natural gas is anticipated to increase over the forecast period, driven by the increasing use of natural gas in power generation, petrochemical plants, hydrogen plants, and oil sands projects.

2.4.4.4 One-Year Tariff Scenario (Tariff Case)

Based on the tariff case assumptions outlined in section 2, “Prices and Capital Expenditure,” specifically section 2.2, “Tariff Scenarios,” the AECO-C price is expected to be 42% below the base case forecast and average Cdn$1.56/GJ in 2025. This decline is due to the 10% U.S. tariff on Canadian energy products, resulting in a widening of the AECO-C and Henry Hub differential but partially offset by a lower exchange rate. The AECO-C price is expected to improve to Cdn$3.16/GJ in 2026, reflecting a narrowing of the differential and higher Henry Hub benchmark prices as tariffs are assumed to be phased out. The differential is anticipated to increase slowly, reaching Cdn$4.09/GJ by 2034, 6.4% lower than the base case and in line with the rise in the Henry Hub price tariff case forecast.

2.4.4.5 Low- and High-Price Cases

The low- and high-price cases capture the near- and long-term volatility of the AECO-C price and are estimated using a 95% confidence interval. The following factors affect the price cases:

Low-price case:

- North American demand is less than expected due to a potential global economic recession.
- North American natural gas production growth is faster than expected.
- Pipeline expansions and LNG projects are delayed or cancelled, causing local and regional bottlenecks and increased gas inventories.
- Oil sands demand growth is constrained due to project deferrals.

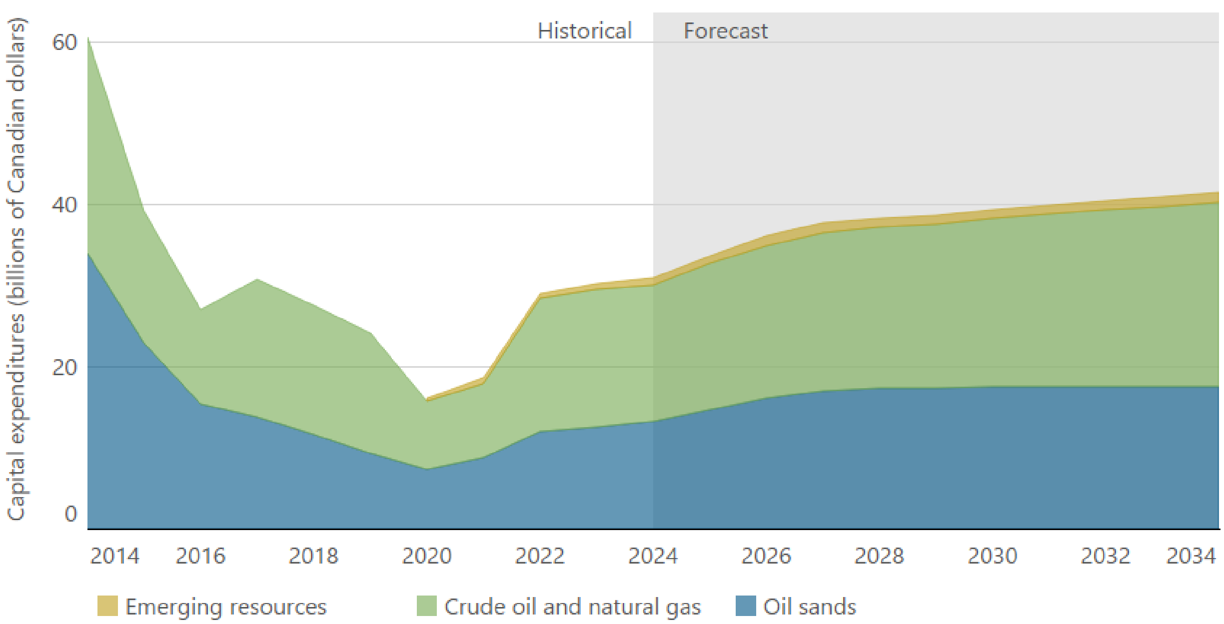
High-price case:

- North American demand rises more than expected due to stronger economic growth.
- North American natural gas production growth is slower than expected.
- North American LNG and pipeline capacity rises faster than expected and decreased gas inventories.
- Oil sands demand growth is faster than expected.

2.5 Capital Expenditures

Figure S1.6 shows historical and forecast values of capital expenditures for Alberta's oil and gas, oil sands, and emerging resources sectors.

Figure S1.6 Alberta oil and gas and oil sands capital expenditures



2024 values are estimated.
Oil sands, crude oil, and natural gas historical values from CAPP.
Emerging resources include geothermal, hydrogen, helium, and lithium. Historical figures are estimated.

2.5.1 Summary

Total capital expenditures were Cdn$30.9 billion in 2024, representing a 2.2% increase from 2023. Sufficiently elevated oil prices in 2024 alongside improved market access from the Trans Mountain pipeline expansion prompted much of the expenditure growth observed across the industry.

From 2025 onwards, enhanced market access due to pipeline expansion and rising crude oil prices over the long term will provide opportunities for crude oil and oil sands investment, while higher natural gas prices will lead to a moderate increase in natural gas investment. Growth is anticipated to be primarily driven by new drilling and continued improvements in operational efficiency.

2.5.2 Oil and Gas Capital Expenditures

2.5.2.1 In 2024

In 2024, the crude oil and natural gas sector (excluding oil sands) kept capital expenditures consistent from 2023 at Cdn$16.8 billion. New drilling prompted by relatively high oil prices and access to high-productivity formations in Petroleum Services Association of Canada (PSAC) areas 2, 4, and 7 provided strong returns on investment.

2.5.2.2 Number of Wells Placed on Production

Crude oil wells: In 2024, 3385 crude oil wells were placed on production in Alberta, up from 2760 wells in 2023.

Natural gas wells: In 2024, 810 natural gas wells were placed on production, down from 921 wells in 2023.

The well activity forecasts for crude oil and natural gas can be found in Table S4.2 and Table S5.3, respectively.

2.5.3 Base Case Forecast for 2025 to 2034

Base case oil and gas capital spending is forecast to increase to Cdn$18.0 billion in 2025. The gradual growth in oil and gas prices, lower interest rates, and elevated drilling activity are anticipated to be the primary drivers of spending. 2025 expenditures present a 7.4% increase from 2024 levels.

Capital expenditures are expected to increase further to Cdn$18.9 billion in 2026 based on the price forecasts. From 2027 onward, oil and gas capital expenditure growth slows to an average yearly growth rate of 2.4%. By 2034, oil and gas capital expenditures are expected to reach Cdn$22.7 billion.

2.5.4 Oil Sands Capital Expenditures

2.5.4.1 In 2024

In 2024, the oil sands sector spent an estimated Cdn$13.3 billion on capital expenditures, representing a 6.4% increase from 2023. As the Trans Mountain pipeline expansion increases export opportunities, and operators continue to focus on debottlenecking and improving operational efficiency. Moreover, sustaining capital for in situ and mining projects, which is capital spent by oil sands producers to maintain or replace fixed assets, increased by 4.7%, outpacing inflation in 2024.

2.5.4.2 Base Case Forecast for 2025 to 2034

With planned increases in pipeline capacity, base case oil sands capital expenditures are forecast to reach Cdn$14.6 billion in 2025. Growing at an average rate of 4.1%, oil sands expenditures peak at Cdn$17.5 billion by 2031 as announced projects begin and complete construction, and operational optimization continues. From 2031 to the end of the forecast period, oil sands investment is expected to remain stable, in line with higher levels of sustaining capital required to maintain new operations.

2.5.5 Emerging Resources Expenditures

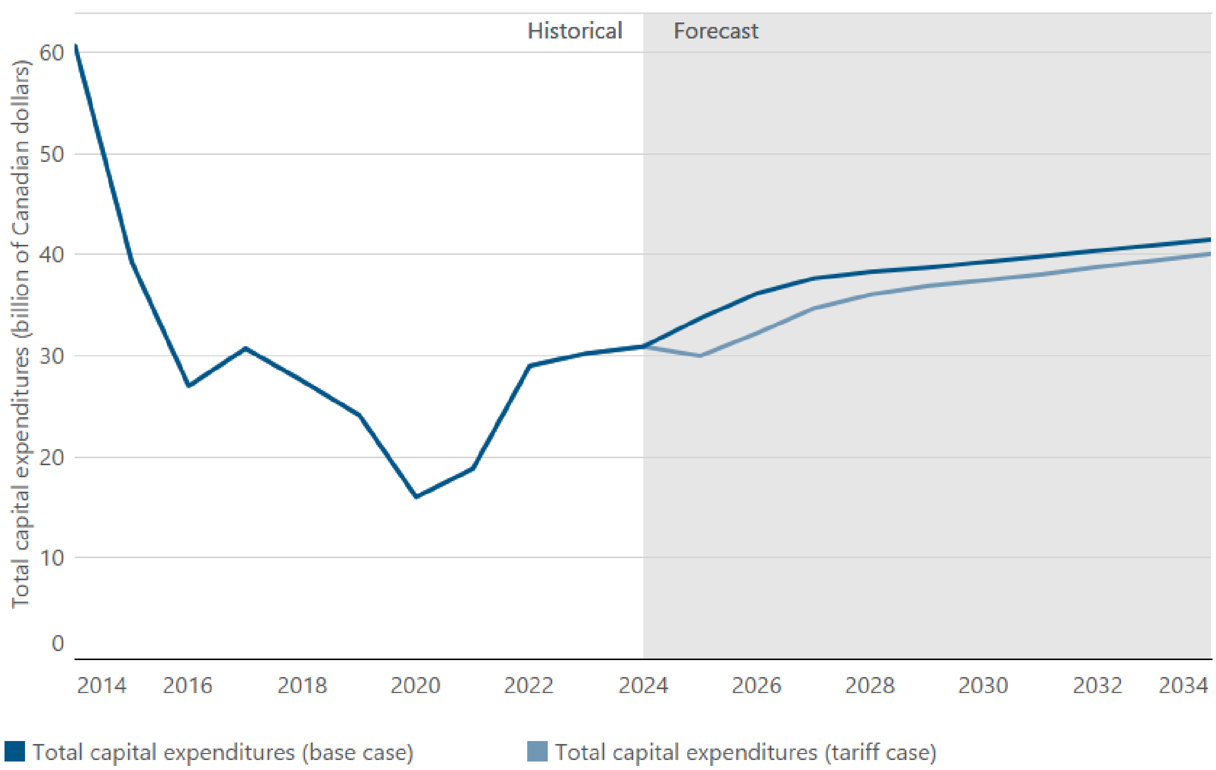
As momentum builds, the emerging resources sector has experienced increased capital spending in 2024. Under the base case, the estimated capital expenditures in 2024 are Cdn$0.79 billion, a 23.3% increase from 2023. This growth is expected to continue, reaching Cdn$1.0 billion in 2025 and growing to Cdn$1.2 billion by 2034. The capital spending forecast is based on public announcements for hydrogen, helium, lithium, and geothermal projects and their relevant estimated capacity additions. Hydrogen capital expenditures do not include spending on carbon dioxide pipelines.

2.5.6 One-Year Tariff Scenario (Tariff Case)

Tariffs are expected to cause higher costs, lower demand, hindered production, and slower drilling growth, resulting in increased uncertainty within the industry. In this situation, producers are expected to practice more disciplined spending, limiting overall expenditures. This scenario assumes tariffs persist for one year, being removed in early 2026. As such, investment falls in 2025 and begins its rebound in 2026 and 2027 as industry readjusts with the return of demand, lower costs, and higher drilling rates.

As tariffs are introduced in 2025, total capital expenditures (oil, gas, oil sands, and emerging resources) are expected to be Cdn$30.0 billion, an 11.1% reduction compared to the base case. Tariff removal fosters strong investment growth as 2026 and 2027 investment grows by 7.5% each year. By 2028, much of the uncertainty is expected to have eased; however, relatively lower prices slow growth to 3.9% as investment reaches Cdn$36.1 billion, 5.9% below the base case. By 2034, capital expenditures are projected to be Cdn$40.1 billion but remain 3.4% lower than base case estimates. Despite anticipated growth, capital expenditures remain below base case values across the forecast period due to forgone investment in previous years and restrained commodity price growth.

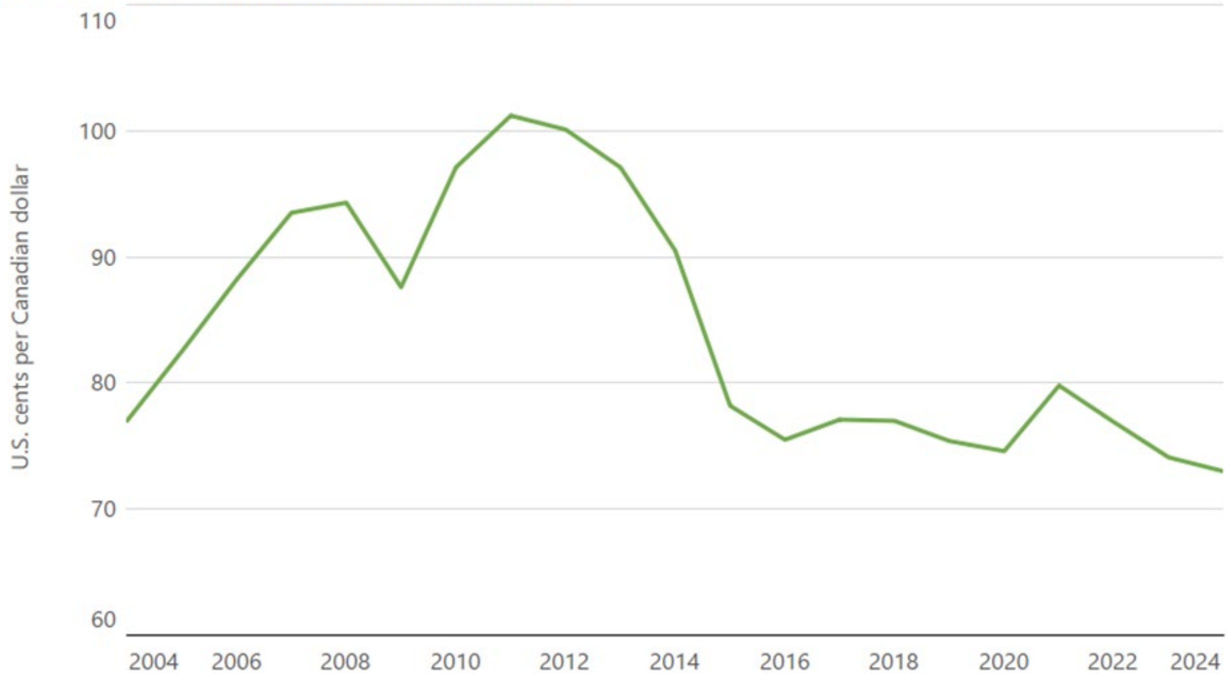
Figure S1.7 Alberta oil and gas, oil sands, and emerging resources capital expenditure (base case vs. tariff case)



2.6 U.S. and Canadian Exchange Rate

Figure S1.8 shows the historical U.S. and Canadian dollar exchange rate.

Figure S1.8 U.S. & Canadian dollar exchange rate



Historical values from the Bank of Canada.

2.6.1 Summary

The U.S. and Canadian dollar exchange rate averaged US$0.73 in 2024, about 1.5% lower than in 2023.

The exchange rate is expected to depreciate to US$0.70 in 2025 due to U.S. tariffs weighing on the demand for the Canadian dollar under the base case forecast. Over the remaining forecast period the exchange rate is projected to gradually increase along with oil prices, stabilizing at US$0.78 in 2029 and holding steady afterwards.

2.6.2 In 2024

The Canadian dollar depreciated 1.5% relative to the U.S. dollar, from US$0.74 in 2023 to US$0.73 in 2024. The exchange rate fluctuated around US$0.74 for the first nine months of the year. However, concerns about the weakness in the Canadian economy, monetary policy divergence between Canadian and U.S. interest rates, and U.S. trade policy uncertainty caused it to depreciate to US$0.70 by December.

2.6.3 Base Case Forecast for 2025 to 2034

The threat of U.S. tariffs on Canadian goods is expected to depress the Canadian dollar over the first half of 2025 before modestly rising over the latter half of the year. The exchange rate is forecast under the base case to average US$0.70 in 2025 and slowly increase to US$0.78 by 2029 as U.S. trade policy uncertainty eases, Canadian economic growth picks up, and the price of oil rises and then holds steady thereafter.

2.6.4 One-Year Tariff Scenario (Tariff Case)

Under this scenario, Canada does not reach a diplomatic agreement with the United States, sparking a broad-ranging trade war that starts in the first half of 2025 and lasts 12 months. Consequently, the Canadian dollar depreciates 8.2% relative to the U.S. dollar, averaging US$0.67 in 2025. With the phase out of tariffs and nontariff measures between Canada and the United States in 2026, the exchange rate is expected to rebound to US$0.69, slowly increasing to US$0.78 by 2029 and remaining steady thereafter.

2.7 Prices and Capital Expenditure Methodology

Energy prices play a key role when deciding on energy development or for assessing remaining reserves. Prices are determined by supply and demand factors, which are influenced by economic activity, seasonal temperatures, market access, and nonmarket factors. All forecasted prices and the exchange rate are compared with publicly available forecasts of the major banks, consultants, and international forecasting agencies.

The crude oil, natural gas, and exchange rate forecasts were compared with TD Economics, RBC Economics, BMO Capital Markets, Scotiabank Economics, ATB Financial, Sproule Associates Limited, GLJ Petroleum Consultants, McDaniel & Associates Consultants Limited, Deloitte LLP, Insite Petroleum Consultants, the U.S. Energy Information Administration, International Monetary Fund, and International Energy Agency’s forecasts, if available.

2.7.1 Crude Oil Prices

2.7.1.1 West Texas Intermediate (WTI)

North American crude oil prices are based on the front-month contract 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.

The near-term forecast for WTI prices is based on the current and expected U.S. and global supply and demand balance within the next three years. Thereafter, prices reflect inflation rates and other factors, such as longer-term global and North American supply and demand trends.

WTI is considered a light sweet crude oil with an American Petroleum Institute (API) gravity of 40 degrees and sulphur content of less than 0.5%.

2.7.1.2 Western Canadian Select (WCS)

The WCS crude oil price forecast is derived from WTI prices at Cushing. The WCS benchmark represents a blend of different bitumen types. The price is based on several factors, including oil sands supply and inventories, demand from U.S. refineries capable of handling heavy oil, transportation costs, availability from Hardisty, Alberta, to Cushing, Oklahoma, the U.S. and Canadian dollar exchange rate, quality, and differences (e.g., sulphur content, density) and indirectly affected by spare capacity and access to tidewater from competing pipelines.

WCS is considered a heavy sour crude oil with an API gravity of 20.5 to 21.5 degrees and a sulphur content of 3.0% to 3.5%. The physical quality distinction between WCS and WTI is relevant as heavy and sour crude oils trade at a discount from light and sweet crude oils.

2.7.2 Natural Gas Prices

2.7.2.1 Henry Hub

Henry Hub, located in Erath, Louisiana, has traditionally been the primary trading hub for natural gas in North America and is the underlying commodity market for futures prices on the NYMEX.

The Henry Hub price forecast for the near term is derived from current data on existing and expected economic activity in the natural gas sector, North American supply and demand, and the export capacity of North American liquefied natural gas terminals. This data is collected from various Canadian and U.S. government agencies, market and industry reports, and company information.

The long-term forecast considers additional economic factors, including inflation, uncertainties surrounding North American supply and demand, government policies, and project completion schedules.

2.7.2.2 AECO-C

The AECO-C price from the Natural Gas Exchange is the Alberta reference price. AECO-C forecast is derived from the U.S. Henry Hub price forecast, accounting for transportation differentials, regional demand, and the U.S. and Canadian dollar exchange rate.

2.7.3 Price Cases

Base price: The most likely price path given what is currently known and expected.

Low- and high-price cases: The low- and high-price cases reflect underlying uncertainties inherent in the base-price case. This is reflected in the short term by implied volatility, estimated using historical prices. Long-term volatility is assumed to grow over time due to increasing uncertainty.

Volatility measures how much prices change over time expressed as a percentage difference of the annual commodity price. Because the price is a function of supply and demand, volatility results from the underlying market supply and demand characteristics.

Both the low- and high-price cases represent the 95th percentile confidence intervals, subject to historical volatility. These intervals grow over time to account for increasing uncertainty.

2.7.4 Prices Forecast Accuracy

2.7.4.1 Crude Oil Prices

The WTI and WCS prices forecast over the past two years have shown reasonably good estimates. The 2024 WTI and WCS price forecasts from last year's publication were 0.4% and 0.8%, respectively, above the actual 2024 prices. Compared to the publication two years ago, WTI and WCS price forecasts were 4.3% and 6.6%, respectively, above the actual 2024 prices.

2.7.4.2 Natural Gas Prices

Natural gas prices are generally more volatile than crude oil prices. On top of supply and demand dynamics, natural gas markets are more affected by seasonal factors, such as weather, which adds to price volatility. Warmer-than-expected winter conditions will lead to oversupply while depressing natural gas demand. The converse is true when winter conditions are colder than expected.

The 2024 Henry Hub and AECO-C price forecasts from last year's publication were 7.7% and 54%, respectively, above the actual 2024 prices. The wider variance for AECO-C was due to wider-than-expected Henry Hub–AECO-C differential. Compared to the publication two years ago, the Henry Hub and AECO-C price forecasts were 37% and 78%, respectively, above the actual 2024 prices. The wide variance was due to milder winter weather, reducing heating demand, which elevated natural gas storage more than anticipated.

2.7.5 U.S. and Canadian Exchange Rate Forecast

Because physical commodities are traded internationally, prices are influenced by the currency exchange rate between the trading partners. Since the U.S. dollar is the underlying currency for commodity markets, the focus is on the U.S. and Canadian dollar exchange rate.

The exchange rate forecast is an input into the crude oil and natural gas forecast models for projecting Canadian commodity prices. The exchange rate assumptions are based on an evaluation of Canadian and U.S. economic indicators, such as gross domestic product, monetary policy and inflation rates, residential and commercial investment, and international trade, and oil price forecasts.

2.7.6 Capital Expenditures

The capital expenditure forecasts for oil sands and conventional oil and gas are based on the production forecasts for natural gas, crude oil, and crude bitumen set out in this report. The AER estimates them separately and then combines them for the total oil and gas capital expenditures.

Historical statistics are from the Canadian Association of Petroleum Producers (CAPP), with the 2024 values being estimates until companies report actual capital expenditures.

2.7.6.1 Oil and Natural Gas

The oil and natural gas capital expenditure forecast represents capital spending on oil and gas drilling and completion, land acquisition, gas plant development, field equipment, geoscience, and enhanced oil recovery. The oil and natural gas capital expenditure forecast is calculated by multiplying the average capital spending per well by the number of new wells placed on production. The number of new wells placed on production is based on crude oil and natural gas production forecasts. The average capital spending per well is calculated using historical capital expenditures and new well counts.

2.7.6.2 Oil Sands

The oil sands capital expenditure forecast comprises the forecast for new and expansion projects and the forecast for sustaining capital expenditures for existing projects.

New and Expansion Projects

Capital spending requirements for new and expansion projects are broken down into in situ thermal, primary, mining, and upgrading project types. Capital cost assumptions for each project type, including both the capital outlay allocation over time and the construction timelines, are based on publicly available information.

The capital expenditure forecast for new and expansion projects includes projects applied for, approved, or under construction and may incorporate some announced projects. These projects have been assessed for the likelihood of meeting the on-stream date and anticipated expenditures.

Sustaining Capital

Sustaining capital expenditures are capital spent by a business to maintain and repair fixed assets and exclude expenses for operations. The AER calculates these expenditures by taking the industry average estimate of sustaining costs per barrel and applying it to the crude bitumen production forecast.

2.7.7 Emerging Resources

The capital expenditure historical and forecast for emerging resources are estimated based on public announcements for hydrogen, helium, geothermal, and lithium projects, including projected capacity additions described in the emerging resources forecast.

3 Crude Bitumen

3.1 Highlights of 2024

Production: Raw bitumen production increased by 4.3% in 2024 to 565.4 thousand cubic metres per day (10^3 m^3/d) or 3557.8 thousand barrels per day (10^3 bbl/d). In 2024, mined bitumen production increased by 4.4% to 273.4 10^3 m^3/d, and in situ production increased by 4.2% to 292.0 10^3 m^3/d.

By 2034, total raw bitumen production is forecast to increase to 645.3 10^3 m^3/d (4060.6 10^3 bbl/d). Future production growth is supported by improved operational efficiency, increased transportation takeaway (pipeline) capacity, and favourable oil prices.

Number of wells: The number of producing wells increased by 3.6% to 10 737 in 2024.

Demand: Total Alberta refinery demand in 2024 (including upgraded and nonupgraded bitumen, crude oil, and pentanes plus) was 91.4 10^3 m^3/d (575.0 10^3 bbl/d). Marketable bitumen (upgraded and nonupgraded bitumen) provided 68.3 10^3 m^3/d (429.8 10^3 bbl/d), or 74.7%, of the total Alberta refinery demand. The remaining marketable bitumen was removed from the province. Alberta refinery demand for marketable bitumen is expected to remain steady with consistent refinery throughputs over the forecast period. Removals are projected to increase throughout the forecast period.

3.2 Tariff Scenarios

Because of significant uncertainty, particularly regarding U.S. tariff policies, this year's report examines two scenarios: a short-term tariff uncertainty scenario (base case) and a one-year tariff scenario (tariff case). The primary difference between these scenarios lies in their tariff assumptions.

- **Base case**: This scenario assumes business as usual and no tariffs. However, the U.S. tariff threats on energy products (oil and gas) persist throughout the first half of 2025 but are ultimately averted through diplomatic negotiations by midyear. Consequently, energy supply and demand are minimally affected.
- **Tariff case**: This scenario assumes a 10% U.S. tariff on energy products (oil and gas) and 25% tariffs on other Canadian goods imposed in the first half of 2025 despite diplomatic efforts. This scenario includes subsequent U.S. and Canadian retaliatory tariffs, other nontariff measures,[8] and additional U.S. tariffs on other trading partners. All tariffs and

[8] Nontariff measures can include quotas or restrictions on imported goods (i.e., liquor), export taxes on electricity, and changes in consumer and business behaviour (i.e., buying Canadian).

nontariff measures between Canada and the United States persist until the end of the first quarter of 2026 before mostly being phased out as the review or renegotiation of the Canada-United States-Mexico Agreement. It is expected tariffs will have some long-term effects and structural changes to the global economy (changes in trade and investment flows).

These tariff assumptions affect prices, costs, commodity profitability, investment, supply and demand, project risk factors, and commercial start dates (where applicable) for most chapters of the report, including comparisons of the outcomes of these scenarios.

3.3 Crude Bitumen Production

3.3.1 Total Production

Total combined in situ and mined bitumen production increased by 4.3% in 2024 to 565.4 10^3 m^3/d or 3557.8 10^3 bbl/d (see the base case Table S3.1).

Under the base case, growth in production is expected to carry over to 2025 with continued investment focusing on optimizing existing assets and reducing debts. By 2034, total raw bitumen production is forecast to increase to 645.3 10^3 m^3/d (4060.6 10^3 bbl/d).

The difference between raw and marketable production is that raw bitumen production refers to the total extracted bitumen, which is highly viscous and requires further processing to meet industry standards, while marketable bitumen production is the processed portion, through blending or upgrading, that meets specifications for transport through pipelines.

Table S3.1 Alberta crude bitumen production highlights (10^3 m^3/d)

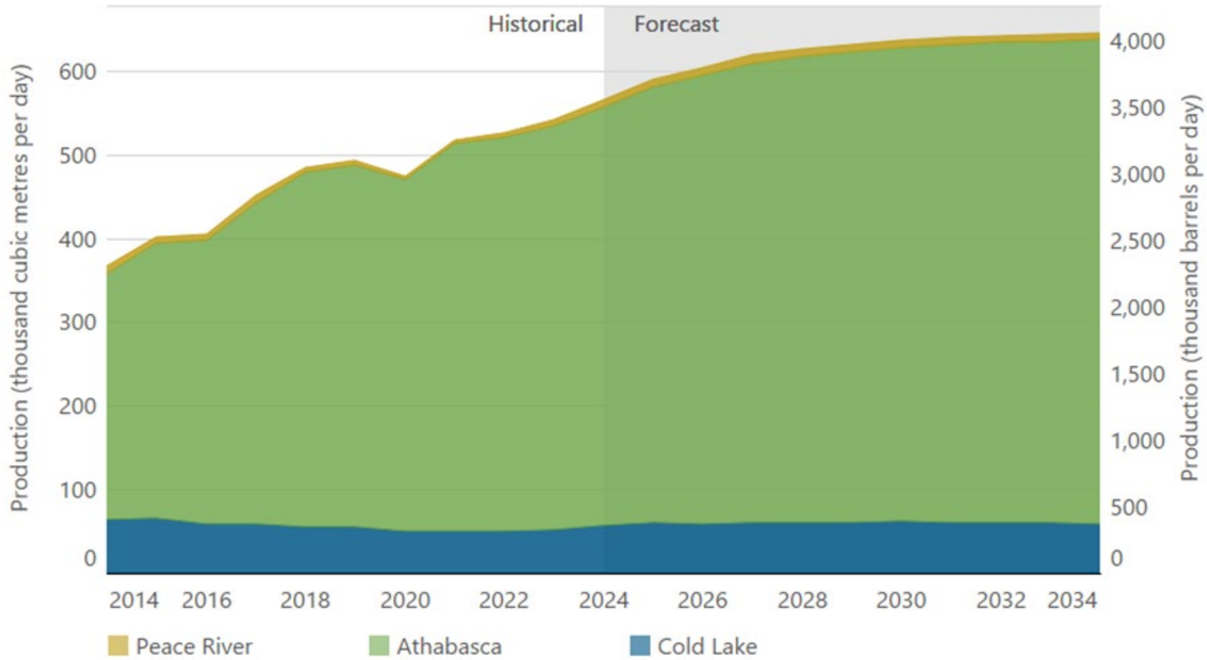
	2023	2024	2025	2026	2034
Raw production					
Mineable	261.9	273.4	280.5	280.6	288.8
In situ	280.2	292.0	309.4	323.4	356.5
Total	542.1	565.4	589.9	604.0	645.3
Marketable production					
Upgraded	188.2	196.6	198.5	199.6	204.5
Nonupgraded	320.4	334.5	347.0	360.1	386.7
Total	508.6	531.1	545.5	559.7	591.2

Note: Upgrading conversion losses result in marketable production totalling less than raw.
Any discrepanices are due to rounding.

3.3.2 Total Production by Oil Sands Area

Total bitumen production in the Athabasca oil sands area increased by 4.0% in 2024 to 499.5 10^3 m^3/d or 3143.6 10^3 bbl/d, accounting for 88% of production in 2024. Under the base case, the Athabasca region is expected to drive the forecast in the near and long term. By 2034, the Athabasca region is forecast to produce 578.3 10^3 m^3/d (3639.4 10^3 bbl/d), accounting for almost 90% of total bitumen production.

Figure S3.1 Total bitumen production by oil sands area (OSA)



3.3.3 Market Conditions

Global market conditions were mixed in 2024. Relatively favourable oil prices, albeit lower, supported growth in oil production and investments. On the other hand, slower global growth led to lower growth in oil demand. Notwithstanding, oil sands production in Alberta continued to grow, supported by various producers' operational optimization, leveraging the increased takeaway capacity provided by the completion of the Trans Mountain pipeline expansion in the middle of last year.

3.3.4 Emerging Trends

Oil sands producers will continue to find ways to optimize their operations. Large companies with specialized knowledge and ample access to capital can reduce costs, maximize their production capacity, and bring new projects to life with more flexibility.

Many oil sands companies are shifting towards lower-emission projects and recovery technologies—including carbon capture, utilization, and storage—to align with sustainability goals.

3.3.5 Impact of Tariffs

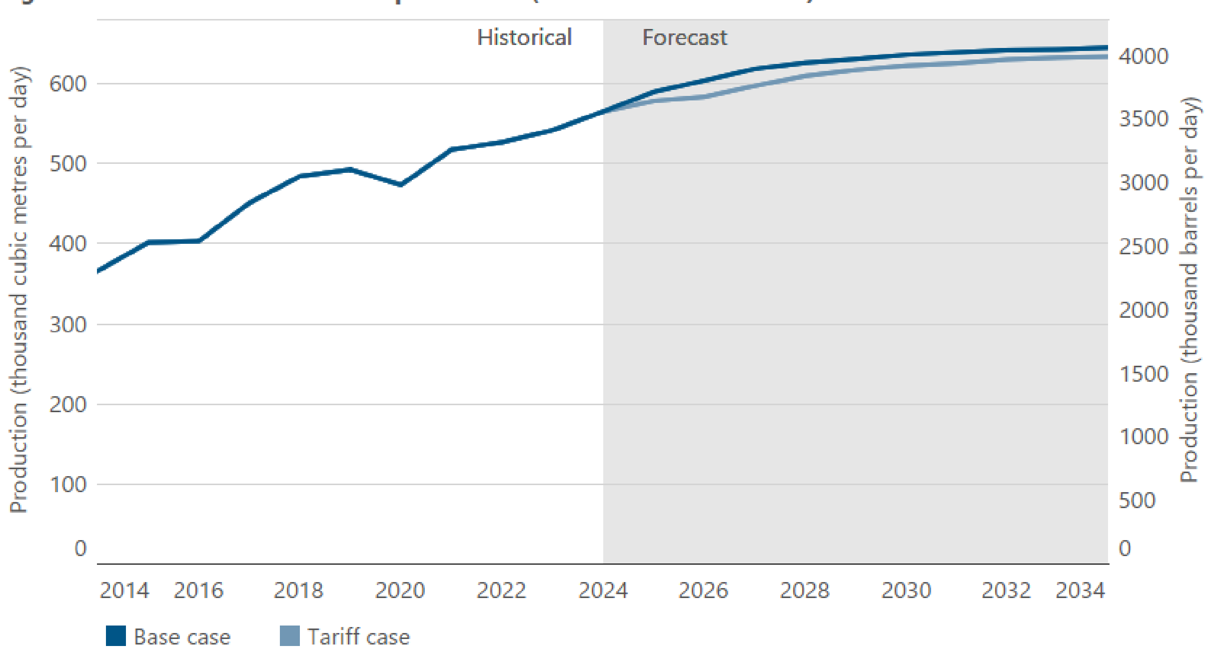
Tariffs on oil and gas exports, along with tariffs to other sectors, are anticipated to remain in place for one year, creating heightened uncertainty, supply chain disruptions, and a broader economic slowdown. Compared to the base case, oil prices are projected to decline while production costs increase, placing downward pressure on profitability and production growth.

Despite these challenges, the overall impact on Alberta's crude bitumen production is expected to be relatively contained, as exports to the United States continue to be demanded mainly driven by many U.S. refineries specifically configured to process bitumen. Production is expected to fall slightly below base case levels under the tariff case, although it will follow a similar trajectory over the forecast period.

In 2025, total bitumen production in the tariff case is expected to be lower by 1.9% from the base case to 578.6 10^3 m^3/d (3640.8 10^3 bbl/d). With tariffs and its effects persist into the next year, the impact is expected to peak with total bitumen production projected to be 3.4% lower than the base case in 2026, growing to 583.8 10^3 m^3/d (3673.7 10^3 bbl/d). As the impacts of the tariff will wane, total bitumen production is expected to grow to 633.9 10^3 m^3/d (3989.0 10^3 bbl/d) in 2034, 1.8% lower than the base case.

Figure S3.2 shows the comparison between the base case and the tariff case.

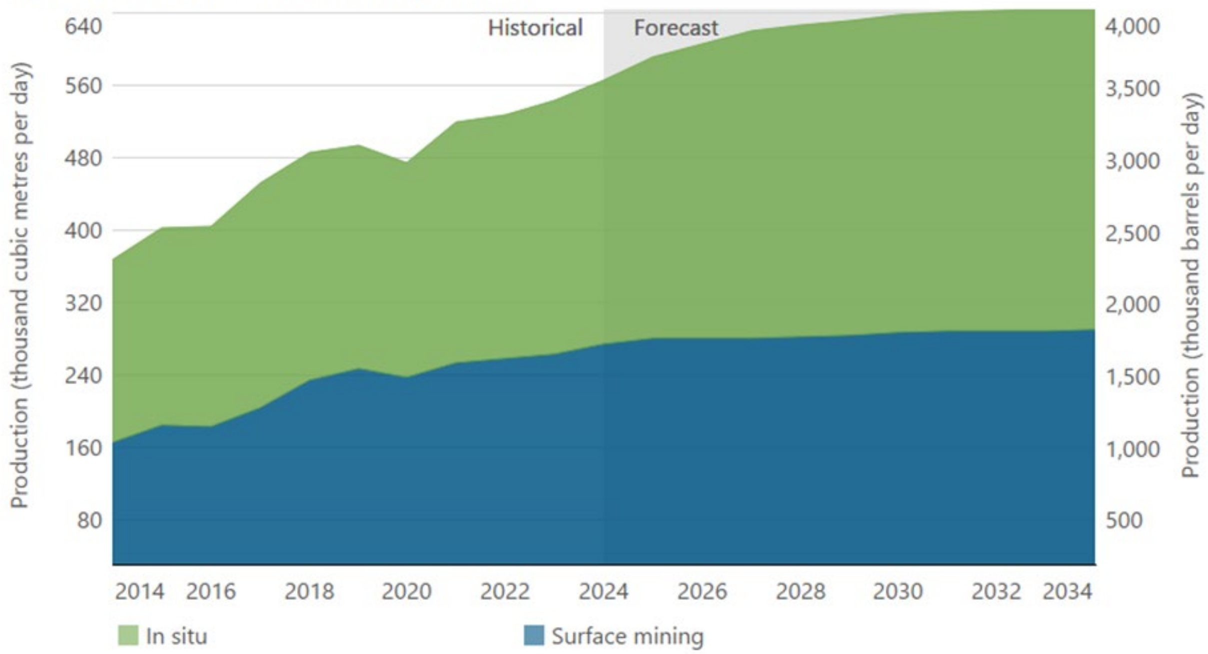
Figure S3.2 Alberta total bitumen production (base case vs. tariff case)



3.4 Mining

Figure S3.3 shows the average daily production of raw bitumen in Alberta from surface mining and in situ projects in the base case.

Figure S3.3 Alberta crude bitumen production



3.4.1 In 2024

In 2024, mined bitumen production increased by 4.4% to 273.4 10^3 m^3/d or 1720.5 10^3 bbl/d. Most mines had increased levels of production, taking advantage of increased pipeline takeaway capacity from Trans Mountain pipeline expansion. The mines that accounted for most of the 2024 production growth are Fort Hills, Horizon, and Jackpine. Mining accounts for 48% of total raw bitumen production.

3.4.2 Highlights

Production data by project are reported in the *ST39: Alberta Mineable Oil Sands Plant Statistics Monthly Supplement*. The following are the 2024 highlights for mined bitumen production:

- Production fluctuated throughout the year, primarily attributable to planned maintenance at several mining sites.
- The strong mining performance was primarily led by optimizations, which drove efficiencies and improved productivity, leading to record production from nearly all mines.
- Production at Suncor's mines rose during the year due to the company's optimized mining operations at Fort Hills and fewer planned maintenance activities at their base mine.

- At Horizon, high utilization rates and the completion of the maintenance optimization project to reduce downtime contributed to achieving its highest production level in 2024.
- The Jackpine mine witnessed its highest production since 2021 due to increased operational efficiencies.
- There was some operator consolidation during the year. CNRL acquired an additional 20% of the Athabasca Oil Sands Project (AOSP) in December 2024, bringing its total working interest to 90%.

3.4.3 Base Case Forecast for 2025 to 2034

A list of proposed projects considered in the forecast is included in the methodology section.

Mined bitumen production will continue to grow in 2025. By 2034, mined bitumen production is forecast to be 288.8 10^3 m^3/d (1817.1 10^3 bbl/d). From 2025 onwards, the estimated average annual growth rate is expected to be about 1%, lower than the average annual 6% growth rate observed during the past decade.

Most of the near-term growth will come from existing facility optimization due to increased productivity, improved market access, and relatively favourable market conditions. Over the latter part of the forecast, expansions and debottlenecking projects are expected to continue driving production growth.

Expansions, pit replacements, and debottlenecking benefit from lower costs by leveraging existing infrastructure, workforce, and materials. Producers will continue identifying and implementing cost-saving measures to enhance efficiency.

No new greenfield mines are expected to be constructed or become operational within the forecast period. Based on the crude bitumen supply costs estimates for 2024, the current price environment and more stringent environmental policies will not encourage the development of new mining projects.

3.4.4 One-Year Tariff Scenario (Tariff Case)

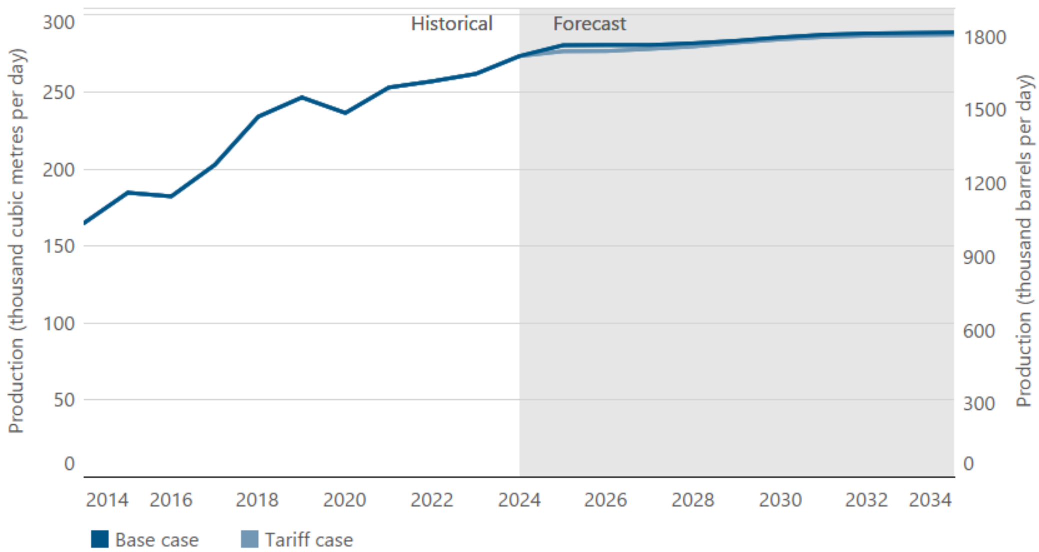
In this scenario, tariffs on oil and gas exports and other sectors are anticipated to last for one year, reducing mining competitiveness with lower oil prices and higher production costs relative to the base case. However, these impacts on mining production are relatively small as only a few mining expansions are proposed, and many U.S. refineries continue to accept bitumen. Mining production is expected to be slightly lower considering the economic and trade headwinds.

Although the overall trajectory resembles the base case, mined bitumen production in the tariff case is expected to be lower by 1.4% from the base case to 276.5 10^3 m^3/d

(1740.2 10^3 bbl/d) in 2025. In the long term, due to the likelihood of a short tariff period, the impact is expected to diminish. In 2034, mining bitumen production is expected to grow to 287.3 10^3 m^3/d (1807.8 10^3 bbl/d).

Figure S3.4 shows the comparison between the base case and the tariff case.

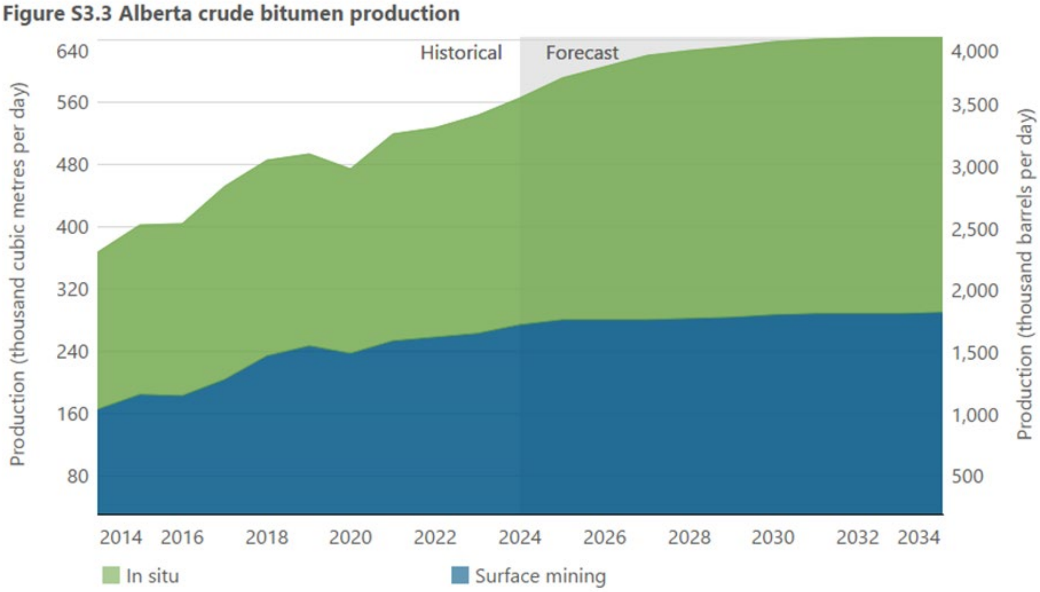
Figure S3.4 Alberta mineable bitumen production (base case vs. tariff case)



3.5 In Situ Production

Figure S3.3 shows the average daily production of raw bitumen in Alberta from in situ projects and surface mining.

Figure S3.3 Alberta crude bitumen production



3.5.1 In 2024

In situ bitumen production increased by 4.2% to 292.0 10^3 m^3/d or 1837.3 10^3 bbl/d. In situ bitumen production accounted for 52% of total raw bitumen production.

In situ production increases occurred across all recovery methods. As shown in Table S3.2, two out of three oil sands areas contributed to the production growth. In situ production increases in 2024 were primarily attributable to growth in the Athabasca region.

Production in the Cold Lake region increased significantly from record production levels by a few projects during the year.

Table S3.2 Production of bitumen in Alberta by oil sands area in 2024 (10^3 m^3/d)

	2023	2024
In situ[a]		
Athabasca	220.2	226.1
Thermal	212.4	219.1
Primary	7.8	7.0
Cold Lake	52.6	57.2
Thermal	43.8	46.3
Primary	8.8	10.9
Peace River	7.1	8.7
Thermal	1.3	1.5
Primary	5.9	7.2
In situ subtotal	280.2	292.0
Mined		
Athabasca	261.9	273.4
Grand total	542.1	565.4

[a] Thermal production includes SAGD, CSS, and Experimental Schemes; primary production includes primary wells, enhanced oil recovery, and conventional bitumen production.

Any discrepanices are due to rounding.

3.5.2 Highlights

Production data by project are reported in the *ST53: Alberta In Situ Oil Sands Production Summary*. The following are the 2024 highlights for in situ bitumen production:

- In situ production continued to grow in 2024 with favourable oil prices.
- With investment focused on expanding existing sites rather than new projects, multiple in situ operations hit record production levels as productivity increased due to targeted facility enhancements, optimization of operations, and debottlenecking.
- Activity rose in the Athabasca region, where most in situ bitumen production occurs. Suncor's Firebag project added over 16 000 bbl/d of production following optimization of its operations.

- The Cenovus Foster Creek project also had record annual production levels, adding over 10 000 bbl/d as production from new well pads continued to ramp up.
- Production was up in the Cold Lake region, driven by the Imperial Cold Lake project. The increase was supported by production from the Imperial Grand Rapids project, which deployed the solvent-assisted steam-assisted gravity drainage (SA-SAGD) technology commercially with lower emissions.
- Primary bitumen production advanced considerably in the Peace River region as companies, such as Baytex Energy, increased production.

3.5.3 Base Case Forecast for 2025 to 2034

A list of proposed projects considered in the forecast is included in the methodology section.

In situ bitumen production volumes in the base case are expected to grow in the near term, in line with oil price forecasts (Table S3.1). By 2034, in situ bitumen output is forecast to be 356.5 10^3 m^3/d (2243.4 10^3 bbl/d), representing an average annual growth of about 2.0%.

Projected production growth is based on favourable market conditions, producers optimizing operations, and expanding their existing facilities from current projects.

Table S3.1 Alberta crude bitumen production highlights (10^3 m^3/d)

	2023	2024	2025	2026	2034
Raw production					
Mineable	261.9	273.4	280.5	280.6	288.8
In situ	280.2	292.0	309.4	323.4	356.5
Total	542.1	565.4	589.9	604.0	645.3
Marketable production					
Upgraded	188.2	196.6	198.5	199.6	204.5
Nonupgraded	320.4	334.5	347.0	360.1	386.7
Total	508.6	531.1	545.5	559.7	591.2

Note: Upgrading conversion losses result in marketable production totalling less than raw.
Any discrepanices are due to rounding.

In situ production will continue to drive the forecast bitumen production growth, supported by pipeline capacity expansion or unused capacity from the Trans Mountain pipeline expansion. Takeaway capacity on the province’s pipeline infrastructure is forecast to improve in the next few years, including Enbridge’s potential expansion of its Mainline pipeline and storage assets. Growth later in the forecast is supported primarily by operational optimization projects, improved market access, and higher oil prices.

Based on 2024 crude bitumen supply costs estimates, in situ expansions are considered a more economical option compared to greenfield in situ or mining projects. This trend indicates that most new bitumen production will likely come from expansion projects and debottlenecking efforts rather than large-scale, new project developments, as they enable increased production at lower costs by optimizing existing infrastructure.

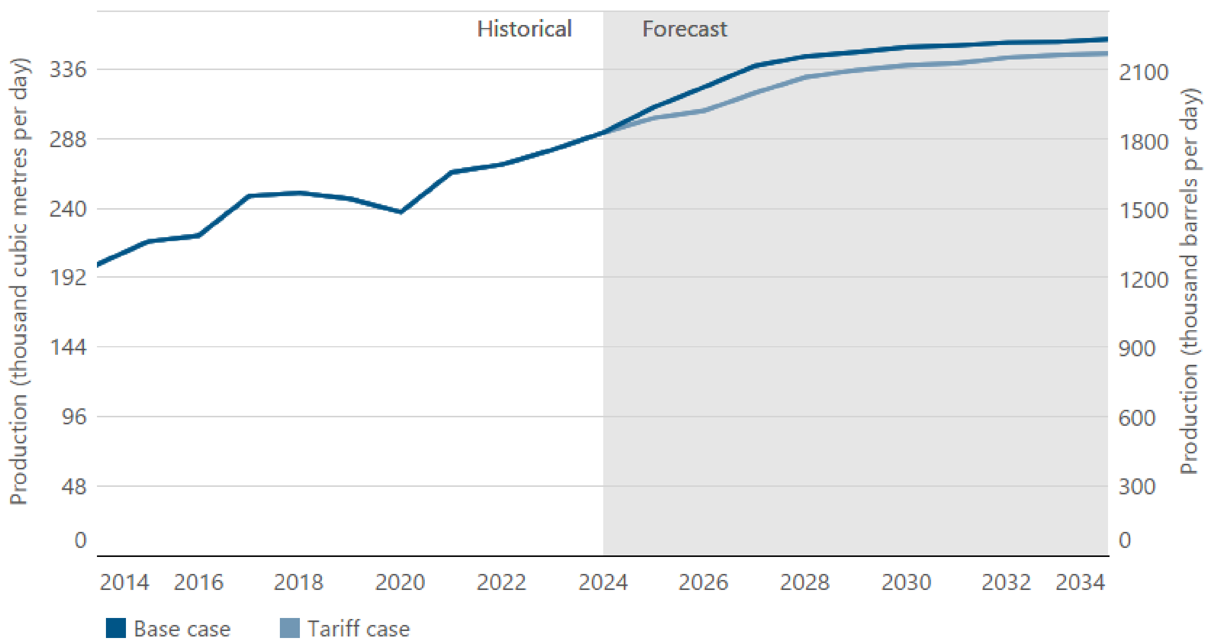
3.5.4 One-Year Tariff Scenario (Tariff Case)

In this scenario, one-year tariffs on oil and gas exports and other sectors impact investment decisions on in situ bitumen production causing delayed project expansions, limiting the pace of capacity and production growth. Although the overall trajectory remains similar to the base case, in situ production is expected to be lower considering heightened uncertainty, supply chain disruptions, and a broader economic slowdown.

In 2025, in situ bitumen production in the tariff case is expected to be 302.0 10^3 m^3/d (1900.7 10^3 bbl/d), 2.4% lower than the base case. In 2027, the in situ production will reach 319.4 10^3 m^3/d (2009.7 10^3 bbl/d), 5.5% lower than the base case as the tariff impacts linger. Thereafter, the production is expected to increase at a faster pace. In 2034, in situ bitumen production is expected to reach 346.6 10^3 m^3/d (2181.2 10^3 bbl/d) 2.8% lower than the base case.

Figure S3.5 shows the comparison between the base case and the tariff case.

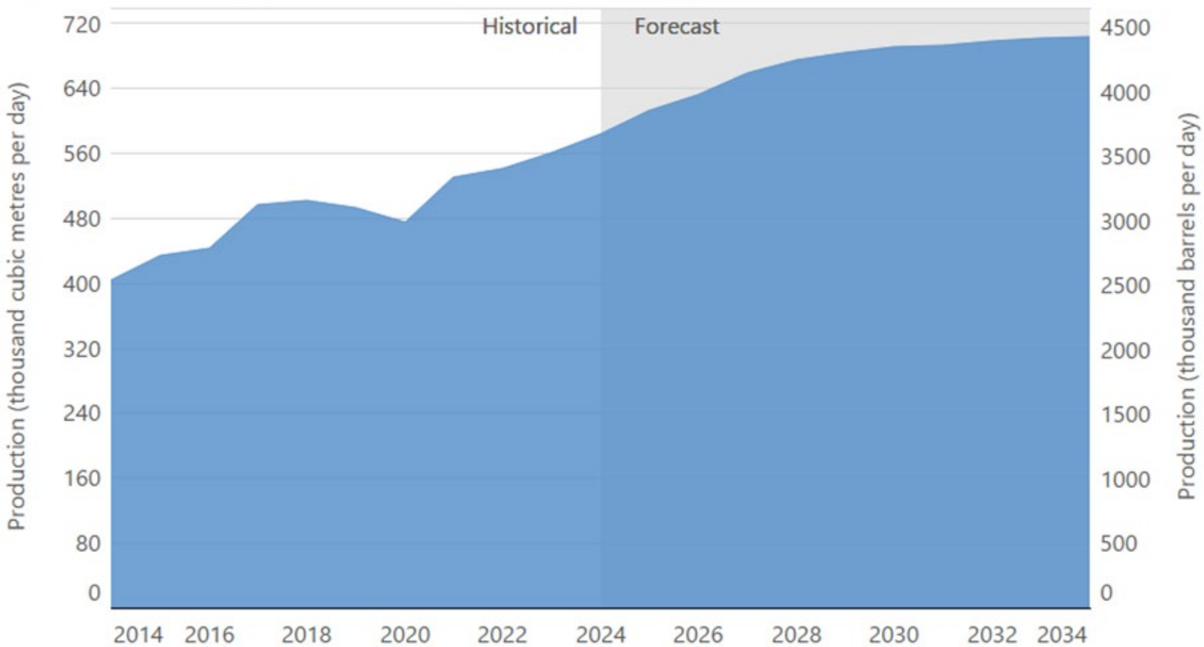
Figure S3.5 Alberta in situ bitumen production (base case vs. tariff case)



3.6 Upgraded Bitumen Production

Figure S3.6 shows the average daily production of upgraded bitumen in Alberta under the base case.

Figure S3.6 Alberta upgraded bitumen (synthetic crude oil) production



3.6.1 In 2024

Upgraded bitumen production increased by 4.5% to 196.6 10^3 m^3/d or 1237.2 10^3 bbl/d.

3.6.2 Highlights

Production data by project are reported in the *ST39: Alberta Mineable Oil Sands Plant Statistics Monthly Supplement*. The following are the 2024 highlights for upgraded bitumen production:

- There was a broad-based increase in upgraded bitumen production across all upgraders in 2024 due to high utilization rates.
- The Suncor upgrader produced record levels of synthetic crude oil (SCO) in 2024 through operational efficiencies and increases in production at the base mine.
- At Horizon, high utilization rates and the completion of the maintenance optimization project to reduce downtime contributed to achieving its highest production level in 2024.
- The Scotford Upgrader achieved its highest growth in production from 2021 levels through piping modifications during the completion of the debottleneck project.
- Due to strong integration with Suncor's other oil sands assets, the Syncrude upgrader also had higher production of SCO last year.

Table S3.3 shows upgraded bitumen production by upgrader.

Table S3.3 Average daily Alberta upgraded bitumen production in 2024

Company/project name	Production (10^3 m^3/d)
Canadian Natural Resources Limited (CNRL) Horizon	39.9
Scotford	50.6
Suncor	55.0
Syncrude	51.1
Total	196.6

Any discrepanices are due to rounding.

3.6.3 Base Case Forecast for 2025 to 2034

A list of proposed projects considered in the forecast is included in the methodology section. Upgraded bitumen production volumes in the base case are expected to continue to grow in the near term, in line with favourable market conditions. By 2034, upgraded bitumen production is forecast to reach 204.5 10^3 m^3/d (1286.8 10^3 bbl/d).

Most of the growth in upgraded production is expected to occur in the early years of the forecast. Operators are expected to maximize utilization rates and pursue optimization projects driven by attractive margins for SCO and favourable market conditions.

As increases in raw bitumen production outpace marginal additions to upgrading capacity, the share of upgraded bitumen in Alberta is expected to decline from 41% in 2024 to 38% by 2034. No new upgrading facilities are assumed to come on stream during the forecast period.

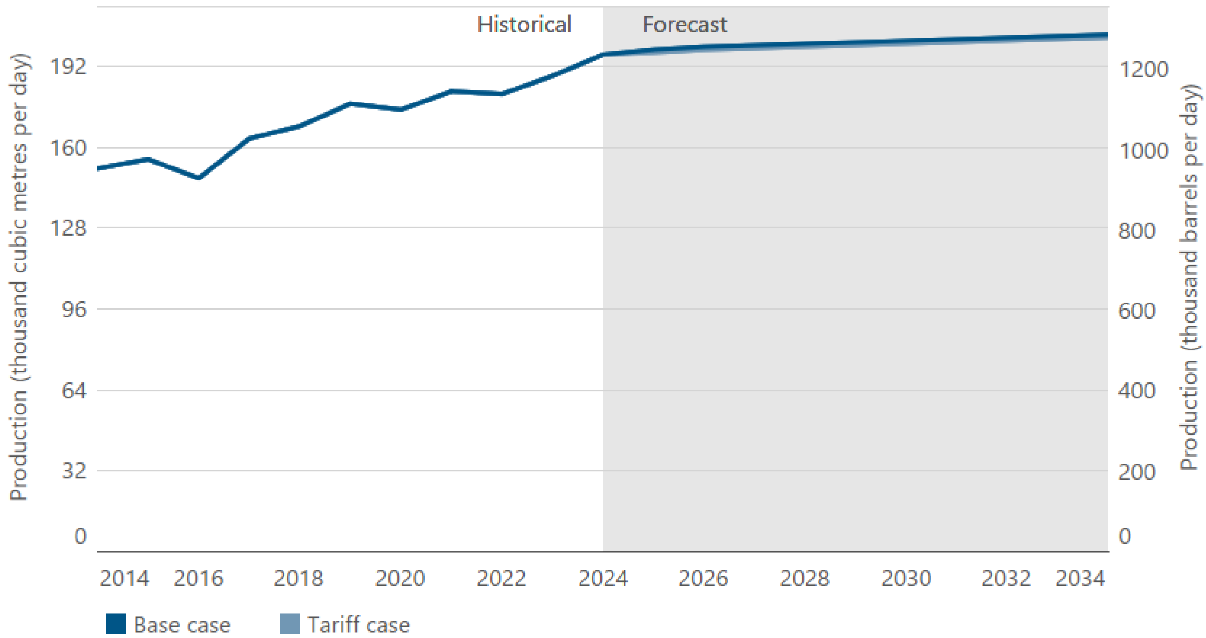
3.6.4 One-Year Tariff Scenario (Tariff Case)

In the tariff case, the impact on upgraded production is expected to be limited, due to the limited number of announced expansion projects and already high utilization rates at existing upgraders. Therefore, upgraded bitumen production is expected to closely follow the trajectory of raw bitumen production in the base case.

In 2025, upgraded bitumen production in the tariff case is expected to be lower by 0.6% from the base case to 197.4 10^3 m^3/d (1242.2 10^3 bbl/d). In 2034, upgraded bitumen production is expected to be 203.3 10^3 m^3/d (1279.6 10^3 bbl/d).

Figure S3.7 shows the comparison between the base case and the tariff case.

Figure S3.7 Alberta upgraded (SCO) bitumen production (base case vs. tariff case)



3.7 Crude Bitumen Well Activity

The rising production reflects technological advancements that have improved well productivity, enabling higher production with fewer wells (see Figure S3.8). However, the number of producing bitumen wells is declining relative to the peak in 2014. Producing bitumen wells rose marginally to 10 737 in 2024 (3.6% more than in 2023).

3.7.1 Production by Recovery Method

For 2024, the in situ production volume breaks down as follows:

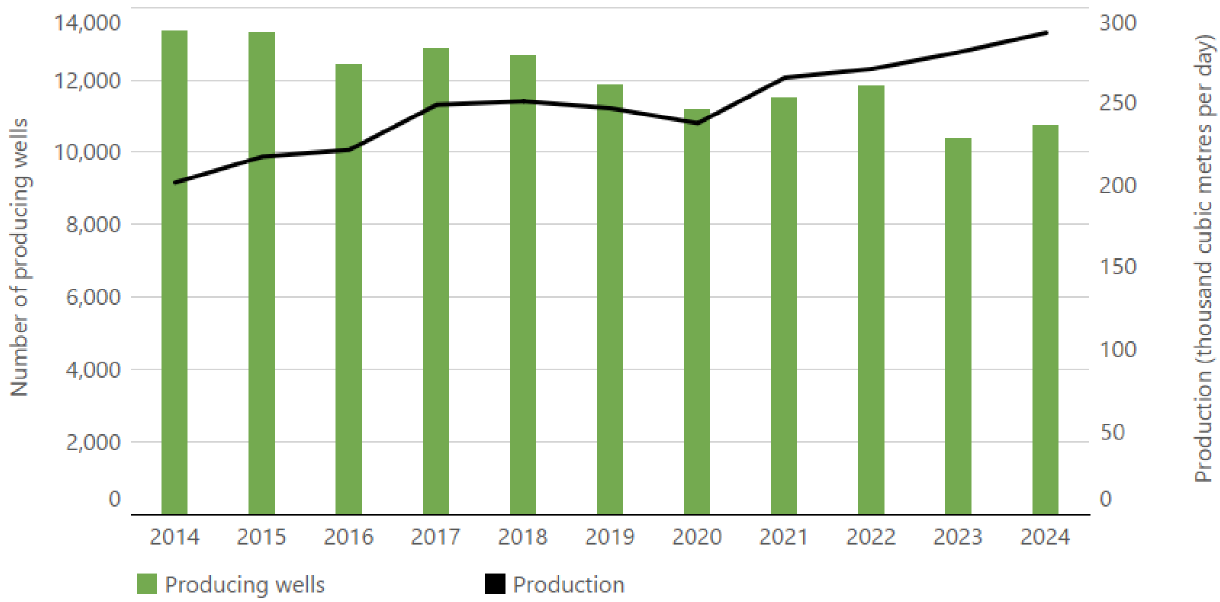
- 75% from steam-assisted gravity drainage (SAGD) operations
- 13% from cyclic steam stimulation (CSS)
- 12% from primary recovery and nonthermal recovery methods

Compared with the 2023 production levels, in 2024,

- SAGD production increased by 3.2% to 218.2 10^3 m^3/d or 1373.2 10^3 bbl/d,
- CSS production increased by 4.7% to 37.2 10^3 m^3/d (233.8 10^3 bbl/d), and
- primary and enhanced oil recovery production increased by 10.3% to 36.6 10^3 m^3/d (230.3 10^3 bbl/d).

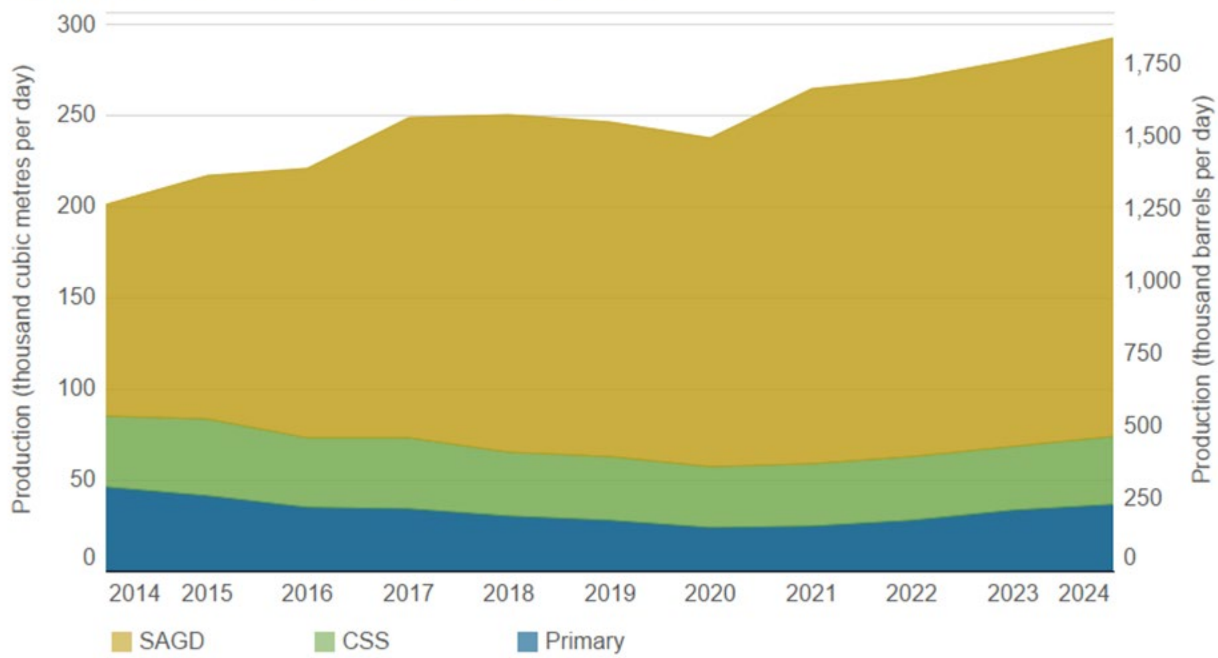
Figure S3.9 shows in situ bitumen production by recovery method.

Figure S3.8 Total producing bitumen wells and in situ production



Note: The wells placed on production include legs and recompletions.

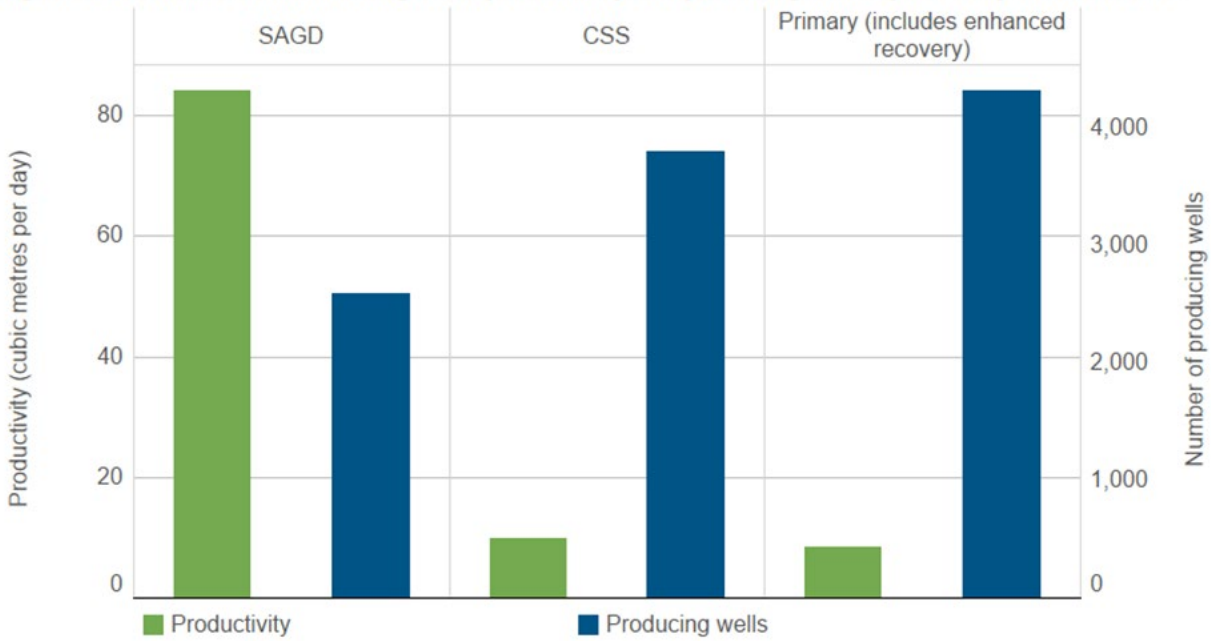
Figure S3.9 In situ bitumen production by recovery method



3.7.2 Well Productivity

In 2024, the weighted average annual productivity of all in situ bitumen wells increased slightly to 27.2 m^3/d. Compared with CSS or primary wells, SAGD wells typically have higher a production rate and more consistent production, but there are more CSS and primary wells (see Figure S3.10).

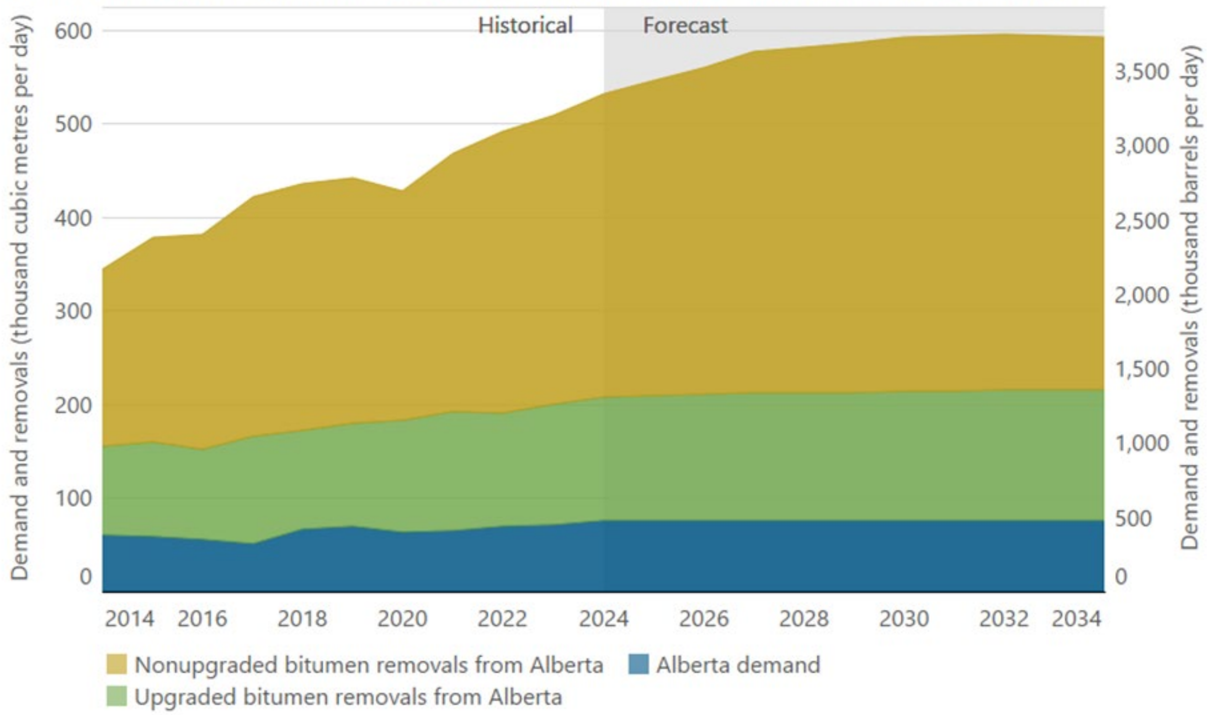
Figure S3.10 In situ bitumen average well productivity and producing wells by recovery method, 2024



3.8 Crude Bitumen Demand

Figure S3.11 shows the historical and forecast of Alberta's demand and disposition of marketable bitumen in the base case.

Figure S3.11 Alberta demand and disposition of upgraded (SCO*) and nonupgraded bitumen



3.8.1 Demand

3.8.1.1 In 2024

The five operating refineries in Alberta had a total processing capacity of 91.4 10^3 m^3/d or 575.0 10^3 bbl/d in 2024. Their combined utilization rate was 103%, handling an estimated daily average of

- 56.9 10^3 m^3/d (357.9 10^3 bbl/d) of upgraded bitumen,
- 11.4 10^3 m^3/d (71.4 10^3 bbl/d) of nonupgraded bitumen,
- 17.8 10^3 m^3/d (112.3 10^3 bbl/d) of crude oil, and
- 5.3 10^3 m^3/d (33.4 10^3 bbl/d) of pentanes plus.

The total estimated Alberta demand in 2024 for upgraded and nonupgraded bitumen (which includes refinery demand and fuel demand used for operations and processing in oil sands projects) was 76.3 10^3 m^3/d (480.0 10^3 bbl/d), a 7.5% increase from 2023.

The Scotford Upgrader had throughput above their nameplate capacity in 2024, while the Sturgeon refinery was below its capacity when processing nonupgraded bitumen.

3.8.1.2 Base Case Forecast for 2025 to 2034

Alberta's demand for upgraded and nonupgraded bitumen is forecast to be 76.5 10^3 m^3/d (481.2 10^3 bbl/d) by 2034. This stable trajectory is expected as no significant expansions or new refineries are likely within the forecast horizon. Upgraded bitumen continues to account for most of the total bitumen demand in the province.

Learn more about refineries in Alberta in the Plants and Facilities section.

3.8.2 Removals

3.8.2.1 In 2024

The breakdown of total oil removals in 2024 was as follows:

- upgraded bitumen, 131.7 10^3 m^3/d (828.6 10^3 bbl/d)
- nonupgraded bitumen, 323.1 10^3 m^3/d (2033.4 10^3 bbl/d)
- crude oil, 66.4 10^3 m^3/d (417.7 10^3 bbl/d)
- pentanes plus as diluent for bitumen transportation, 119.4 10^3 m^3/d (751.1 10^3 bbl/d)

Upgraded bitumen removals increased by 2.1% due to rising production. Nonupgraded removals increased by 4.6% compared with 2023, mostly driven by the growth in nonupgraded bitumen production and increased pipeline takeaway capacity as Trans Mountain pipeline expansion became operational.

3.8.2.2 Base Case Forecast for 2025 to 2034

Upgraded and nonupgraded removals are expected to increase by 2034, alongside rising production and improved pipeline capacity over the forecast period, while Alberta's demand remains relatively stable.

The following are the removals in 2034 and the per cent changes relative to 2024 levels:

- upgraded bitumen, 139.4 10^3 m^3/d (877.0 10^3 bbl/d) (5.8% increase)
- nonupgraded bitumen, 375.4 10^3 m^3/d (2362.2 10^3 bbl/d) (16.2% increase)
- crude oil, 65.0 10^3 m^3/d (408.9 10^3 bbl/d) (2.1% decrease)
- pentanes plus as diluent, 148.4 10^3 m^3/d (933.7 10^3 bbl/d) (24.3% increase)

Upgraded and nonupgraded bitumen will continue to account for most of Alberta's oil removals. Alberta's crude bitumen removals are primarily sent to the United States by pipeline and rail, with a portion sent to the U.S. west coast or other international destinations through shipments by sea. Learn more about petroleum pipelines and rail transportation in Alberta in the “Pipelines and Other Infrastructure” section.

3.8.2.3 One-Year Tariff Scenario (Tariff Case)

Alberta demand is expected to decline slightly in the short term due to the broader economic slowdown following the imposition of tariffs on oil and gas and other sectors. However, the relatively stable driving demand and limited availability of close substitutes to petroleum products across many industries are expected to cushion the decline.

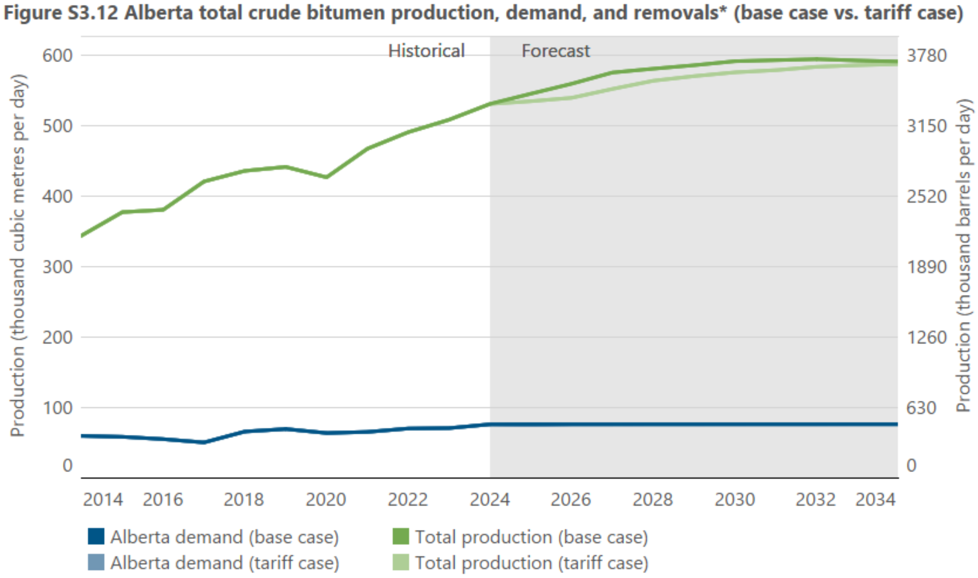
Relative to the base case, Alberta demand is expected to be slightly lower by 1.4%, reaching 75.2 10^3 m^3/d (473.5 10^3 bbl/d) before returning to the base case trajectory after 2027.

For removals, we expect a marginal decline from the base case, given the sustained demand from U.S. refineries. A significant capacity of refineries in Petroleum Administration for Defense Districts (PADD) 2, 3, and 4 is specifically designed to process bitumen.

Compared with the base case, total removals for bitumen are expected to be lower by 2.0%, reaching 459.7 10^3 m^3/d (2892.6 10^3 bbl/d) in 2025. In the long term, removals of Alberta crude bitumen may soften depending on the duration and intensity of the tariffs and whether the United States (Canada’s primary market for crude bitumen) can find alternative sources for heavy crude.

Figure S3.12 shows total production, Alberta demand, and removals in the base case and tariff case.

Figure S3.12 Alberta total crude bitumen production, demand, and removals* (base case vs. tariff case)



*The difference between supply and demand are removals.

3.9 Crude Bitumen Supply Costs

The supply cost of a resource project is the minimum constant dollar price needed to recover all capital expenditures, operating costs, royalties, and taxes and earn a specified return on investment. The supply cost indicates whether a project is economically viable.

In Situ: Supply costs for in situ projects range from around US$47/bbl for expansion projects to US$58/bbl for greenfield projects in the base case. Brownfield expansion projects tend to be more profitable than greenfield projects due to lower supply costs.

Mining: Supply costs for mining projects range from US$50/bbl to US$78/bbl in the base case. Similar to in situ brownfield expansions, mining brownfield expansions have lower supply costs than greenfield surface mines due to the ability to leverage existing infrastructure, reducing both capital and operating expenses.

Despite technological innovations and other measures to lower operating costs, significant upfront capital costs for mining projects continue to challenge the economic viability of greenfield projects.

Table S3.4 shows 2024 crude bitumen supply costs in the base case with a selection of key assumptions, such as capital costs, project capacities, and utilization rates.

Table S3.4 Alberta crude bitumen supply costs in 2024 (base case)

	Production		Capital cost range	Capacity utilization	Estimated supply cost
Project type	(10^3 m^3/d)	(bbl/d)[a]	(millions of dollars)	(Per cent)[b]	($US WTI equivalent per barrel)
In situ SAGD	6.4	40,000	621 – 1,468	90	47 – 58
Surface Mine	15.9	100,000	5,400 – 11,880	95	50 - 78

[a] bbl/d = barrels per day.

[b] Represents the average current capacity utilization rate of operators

Input cost data are based on 2024 Canadian dollars, whereas the resultant supply costs per barrel are converted to U.S. dollars to compare with the West Texas Intermediate (WTI) benchmark.

The supply cost estimates for 2024 assume that oil sands projects adhere to the *Technology Innovation and Emissions Reduction Regulation* (*TIER*) to meet facility emission benchmarks. Facilities that do not directly meet their benchmark can also comply by submitting offsets, performance credits, or payment into the *TIER* fund. These carbon costs are factored into the supply cost estimates for in situ and mining projects.

3.9.1 One-Year Tariff Scenario (Tariff Case)

In the tariff case, with wider oil price differentials and higher capital and operational costs, supply costs for brownfield expansion projects are estimated to be 8.5% higher, relative to the base case for in situ and 4.0% higher compared to mining operations.

Table S3.5 shows 2024 crude bitumen supply costs for the tariff case.

Table S3.5 Alberta crude bitumen supply costs in 2024 (tariff case)

	Production		Capital cost range	Capacity utilization	Estimated supply cost
Project type	(10^3 m^3/d)	(bbl/d)[a]	(millions of dollars)	(Per cent)[b]	($US WTI equivalent per barrel)
In situ SAGD	6.4	40,000	639 – 1,511	90	51 - 63
Surface Mine	15.9	100,000	5,670 – 12,474	95	52 - 80

[a] bbl/d = barrels per day.

[b] Represents the average current capacity utilization rate of operators

3.10 Crude Bitumen Methodology

3.10.1 Production Forecast

3.10.1.1 Mined Bitumen

Production from existing facilities and supply from future projects are considered in Table S3.6. Production from future mining projects considers the cost of engineering, materials, and the skilled labour needed to expand existing projects and build new ones. Other factors considered include the long-term forecast of oil prices and capital investment availability.

All approved and applied-for projects have been considered based on their likelihood of meeting their on-stream date and production capacity. This involves weighing the risks for each project. Some projects considered will ultimately not be included in the ten-year forecast due to the high level of uncertainty about whether they will come on stream within the next decade.

3.10.1.2 In Situ Bitumen

Like surface mining, the supply forecast of in situ bitumen includes production from existing projects, expansions to existing projects, and new projects. All approved and applied-for projects have been considered (see Table S3.7). The forecast assumes that all existing projects will continue producing at normal production levels over the forecast period.

Projects considered for the forecast are assessed for the likelihood of meeting the on-stream date and stated production capacity. This involves weighing the risks for each project. Some projects considered will ultimately not be included in the ten-year forecast due to the high level of uncertainty about whether they will come on stream within the next decade.

In projecting primary bitumen production, the AER combines expected production from currently active wells and new wells placed on production. The number of new wells placed on production and their average initial productivity and decline rates are the main determining factors in projecting production volumes. Like the crude oil well methodology, an economic model is used to determine the number of primary wells placed on production to form the basis of the forecast.

The production forecast for future crude bitumen projects accounts for the past performance of similar schemes (including production and energy demand intensities), project modifications, the long-term forecast of crude oil and natural gas prices, light crude and bitumen price differentials, and the ability of North American markets to absorb increased volumes. Factors that may affect the pace of development, such as the availability of labour and equipment, were considered in the forecast.

3.10.1.3 Upgraded Bitumen

Table S3.8 lists all future projects considered in the forecast. The AER considers the cost of engineering, materials, and the amount of skilled labour required to expand existing projects and build new ones. Other key factors are assessed, including the long-term crude oil price forecasts, the price differential between light crude oil and bitumen, the length of the construction period of an upgrader, and the market penetration of new upgraded volumes, all of which will affect project timing.

3.10.2 Crude Bitumen Production Forecast Accuracy

The crude bitumen production forecast over the past five years have shown reasonably good accuracy. The forecast deviation from the 2024 actual crude bitumen production ranged from 0% to 2%. The high accuracy is supported by improvements made to our models and assumptions over time, allowing for more precise alignment with actual outcomes.

3.10.3 Demand Forecast

The bitumen demand forecast largely considers upgrading and refining capacity. Marketable production exceeding Alberta’s demand is assumed to be exported to other markets. Markets traditionally served by Alberta’s bitumen are assessed for opportunities and limitations, including maintenance schedules, transportation constraints, and competing supplies of crude oil.

3.10.4 Supply Costs

Supply costs are 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. After accounting for transportation costs and exchange rates, bitumen supply cost calculations enable projects to be compared with other crude oil benchmarks. This price can also be compared with current market prices to assess whether a project or resource is economically attractive.

3.10.5 Assumptions

Reference projects in our supply cost estimates include in situ SAGD and standalone mining with cogeneration. Although each project is unique in its location and in the quality of its reserves, our supply cost analyses rely on a range of project specifications, including capital and operating cost information gathered from applications and company investment plans.

SAGD capital costs cover a wide range of values—the lower range represents additional expansion phases where portions of the infrastructure are already in place, and the upper range represents capital costs for greenfield projects.

A major component of operating costs is natural gas purchased for fuel and feedstock. For 2025 and beyond, our analysis assumes a nominal discount rate of 10%.

Carbon cost assumptions for new oil sands projects are considered in the supply cost estimates. It is assumed that oil sands projects will adhere to *TIER* to meet facility emission benchmarks. Facilities that do not directly meet their benchmark can also comply by submitting offsets, performance credits, or payment into the *TIER* fund.

3.10.6 Data

All 2024 data is as reported by industry until the end of December and does not capture any subsequent amendments. We used crude bitumen production volumes submitted to Petrinex.

4 Crude Oil

4.1 Highlights of 2024

Production: Crude oil production increased by 3.5% in 2024, averaging 84.2 thousand cubic metres per day (10^3 m^3/d) or 530 thousand barrels per day (10^3 bbl/d). Crude oil accounted for 12% of total marketable oil production, including bitumen and pentanes plus in Alberta.

Number of Wells: After a decrease in new wells placed on production in 2023, new wells rebounded by 23% in 2024. This rebound was driven by increased activity due to favourable oil prices, low interest rates, increased drilling in productive formations, the commencement of the Trans Mountain pipeline expansion, and ongoing improvements in operational efficiency.

The number of new wells placed on production is projected to decrease slightly from 3385 in 2024 to 3080 by 2034, with most new wells targeting the Cardium and Montney Formations and the Mannville Group.

Demand: In 2024, Alberta refinery demand for total oil (upgraded and nonupgraded bitumen, crude oil, and pentanes plus) was 91.4 10^3 m^3/d (575 10^3 bbl/d). Crude oil accounted for 20% of Alberta's refinery throughput at 17.8 10^3 m^3/d (112.3 10^3 bbl/d). The remaining crude oil produced was removed from the province. Without new refineries or significant refinery expansions planned, Alberta's demand for crude oil is expected to remain relatively unchanged with stable refinery throughput. Crude oil removals are projected to increase over the forecast.

4.2 Tariff Scenarios

Because of significant uncertainty, particularly regarding U.S. tariff policies, this year's report examines two scenarios: a short-term tariff uncertainty scenario (base case) and a one-year tariff scenario (tariff case). The primary difference between these scenarios lies in their tariff assumptions.

- **Base case**: This scenario assumes business as usual and no tariffs. However, the U.S. tariff threats on energy products (oil and gas) persist throughout the first half of 2025 but are ultimately averted through diplomatic negotiations by midyear. Consequently, energy supply and demand are minimally affected.
- **Tariff case**: This scenario assumes a 10% U.S. tariff on energy products (oil and gas) and 25% tariffs on other Canadian goods imposed in the first half of 2025 despite diplomatic efforts. This scenario includes subsequent U.S. and Canadian retaliatory tariffs, other nontariff measures, and additional U.S. tariffs on other trading partners. All tariffs and nontariff measures between Canada and the United States persist until the end of the first

quarter of 2026 before mostly being phased out as the review or renegotiation of the Canada-United States-Mexico Agreement. It is expected tariffs will have some long-term effects and structural changes to the global economy (changes in trade and investment flows).

These tariff assumptions affect prices, costs, commodity profitability, investment, supply and demand, project risk factors, and commercial start dates (where applicable) for most chapters of the report, including comparisons of the outcomes of these scenarios.

4.3 Crude Oil Production

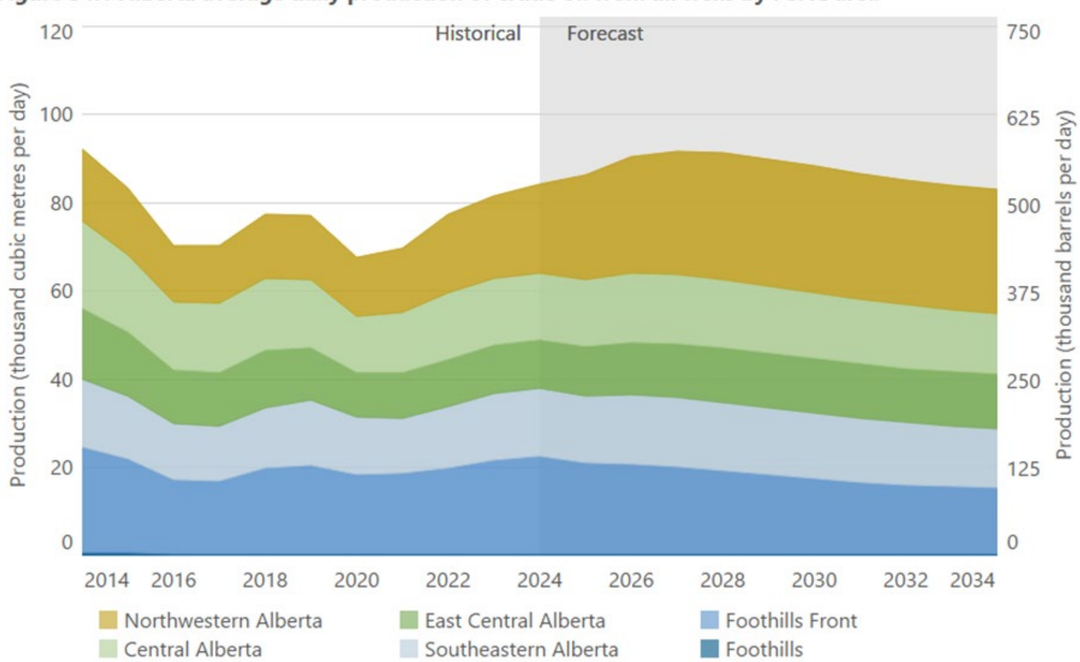
4.3.1 Summary

Alongside a drop in global oil prices in 2024, inflation in Alberta has remained above 2% leading to higher capital and operating costs for oil production. In light of these challenges, new wells drilled grew by 23%, indicating that prices were high enough to ensure a good return on new investments. Consequently, crude oil production increased by 3.5% in 2024.

The increase in crude oil production has reached a nine-year high, showing robust operations in Alberta. Light crude oil comprised 56% of 2024 production and ultra-heavy crude oil 23%. Production increases were most apparent in high-value areas within Petroleum Services Association of Alberta (PSAC) areas 2 and 7.

Figure S4.1 shows the average daily crude oil production from all wells by PSAC area.

Figure S4.1 Alberta average daily production of crude oil from all wells by PSAC area



4.3.2 Production in 2024

In 2024, production increased to 84.2 10^3 m^3/d or 530 10^3 bbl/d, a 3.5% increase from 81.4 10^3 m^3/d (512.2 10^3 bbl/d) in 2023.

Despite prices dropping slightly in 2024, production growth has persisted primarily due to productive formations such as the Cardium and Montney (in PSAC 2) and the Peace and Spirit River (in PSAC 7). These formations provided sufficiently high financial returns to support increased drilling and production. Horizontal well optimization has also supported production growth. With most wells drilled being horizontal, the efficiency gains from hydraulic multistage fracturing and improved technology have helped to keep operations efficient (see section 4.4, "Crude Oil Well Activity,").

Crude oil production in 2024 consisted of

- 56.4% light crude oil,
- 14.2% medium crude oil,
- 6.6% heavy crude oil, and
- 22.8% ultra-heavy crude oil.

Producers are increasingly commercializing formations with large volumes of light and ultra-heavy crude oil, such as the Cardium Formation, Montney Formation, and Mannville Group, due to the price premium on light oil and the relatively better economic returns on ultra-heavy oil.

Table S4.1 shows the crude oil production and wells placed on production in 2023 and 2024 and includes base case forecasts to 2034.

Table S4.1 Alberta crude oil production and new wells placed on production highlights

	2023	2024	2025	2026	2034
Crude oil production (10^3 m^3/d)					
Light	45.4	47.5	47.7	49.6	43.4
Medium	12.9	12.0	12.1	12.6	11.5
Heavy	5.9	5.6	5.6	5.8	5.3
Ultra-heavy	17.2	19.2	20.6	22.5	22.8
Total	81.4	84.2	86.1	90.4	82.8
Number of wells placed on production					
Vertical	31	15	20	20	20
Horizontal	2729	3370	3145	3145	3060
Total	2760	3385	3165	3165	3080

Any discrepanices are due to rounding.

Note: The number of wells placed on production include legs and recompletions.

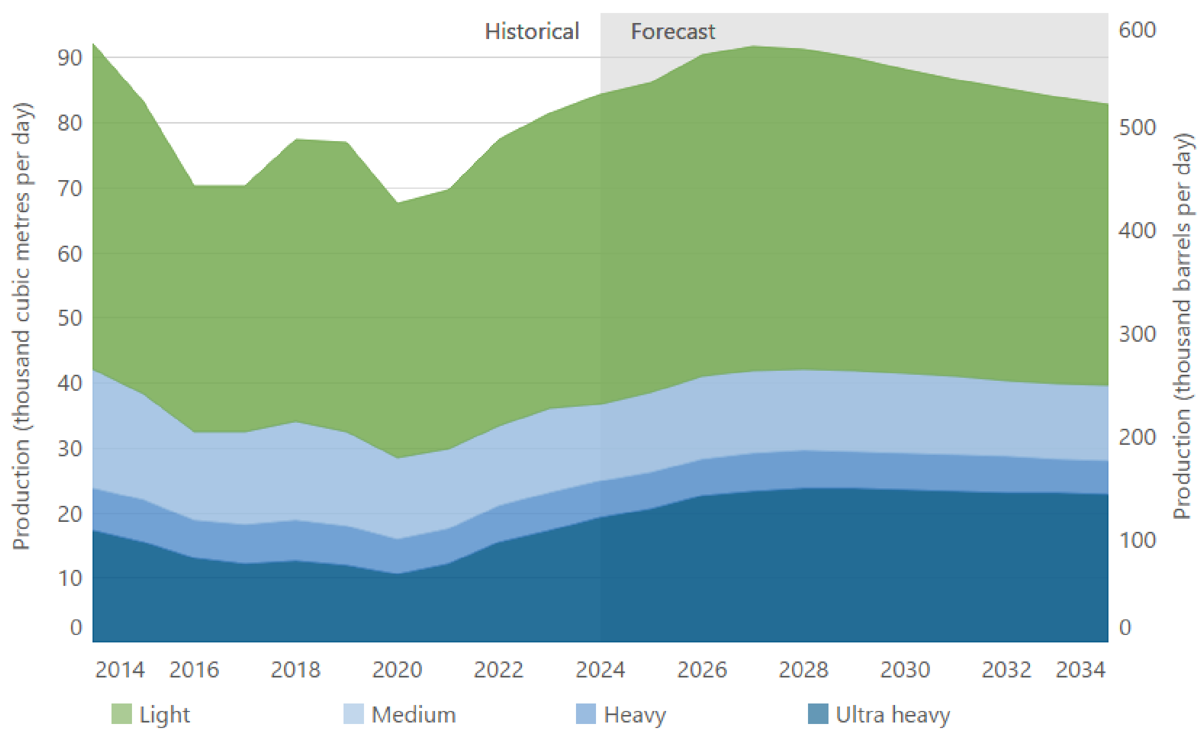
4.3.3 Base Case Forecast for 2025 to 2034

Based on the oil price forecast, total crude oil production is expected to increase from 84.2 10^3 m^3/d (530 10^3 bbl/d) in 2024 to a peak of 91.6 10^3 m^3/d (576.3 10^3 bbl/d) by 2027, as the number of new wells placed on production remains relatively elevated. Producers are expected to take advantage of the Trans Mountain pipeline expansion. However, a decline in crude oil production to 82.8 10^3 m^3/d (521.2 10^3 bbl/d) is anticipated by 2034 as the number of new wells drilled is not expected to offset the decline in production of existing wells.

The share of light crude oil production is expected to decrease from 56.4% in 2024 to 52.3% by 2034, whereas ultra-heavy crude oil production is expected to increase from 22.8% in 2024 to 27.5% by 2034.

Figure S4.2 shows the average daily production of crude oil by density.

Figure S4.2 Alberta average daily production of crude oil by density



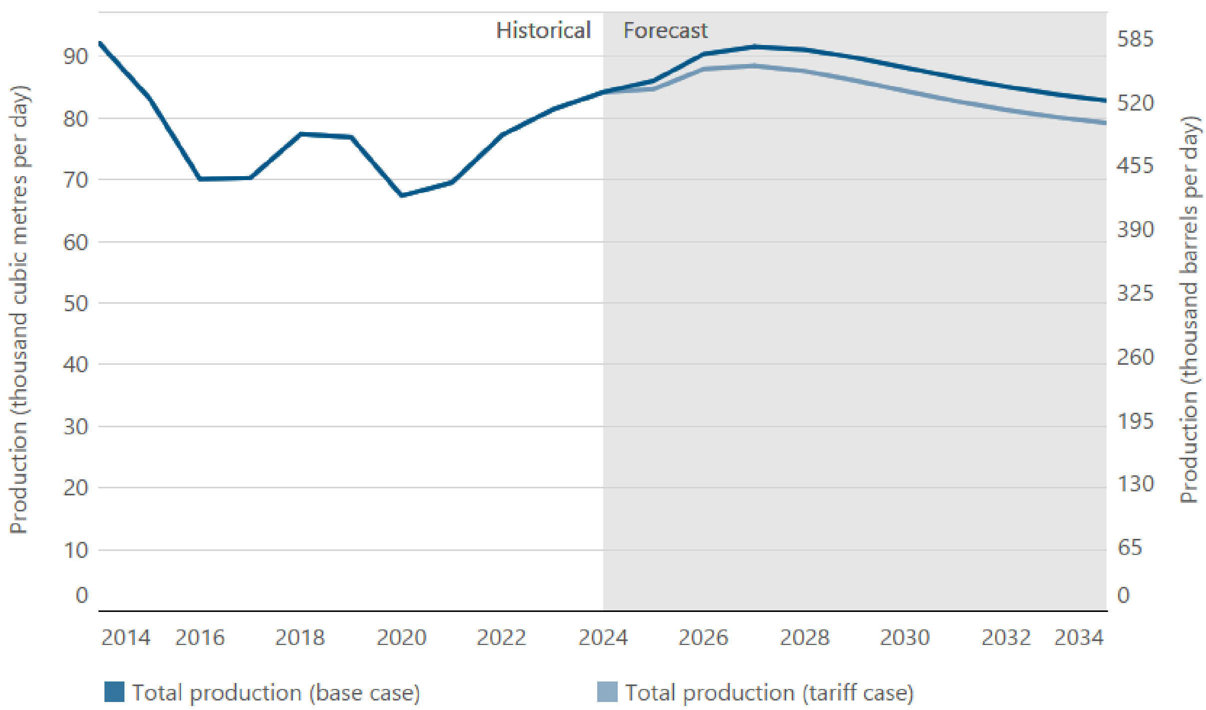
4.3.4 One-Year Tariff Scenario (Tariff Case)

Tariffs applied to oil and gas exports are expected to last one year, resulting in increased uncertainty and supply chain disruptions. In the tariff scenario, compared with the base case, lower oil prices and higher production costs are forecast primarily due to retaliatory tariffs. Consequently, production levels are expected to fall below the base case forecast despite a similar forecast trajectory.

Production in 2025 is expected to be 2% lower than the base case at 84.7 10^3 m^3/d (533.1 10^3 bbl/d). Crude oil production rebounds in 2026 and peaks in 2027 at 88.5 10^3 m^3/d (557.0 10^3 bbl/d) before gradually declining to around 79.2 10^3 m^3/d (498.4 10^3 bbl/d) by 2034. Forecasted production is expected to be, on average, 4% below the base case due to the initial reduction in new wells placed on production and lower prices throughout the forecast period.

Figure S4.3 depicts projected crude oil production in both the base case and tariff case forecasts.

Figure S4.3 Alberta total crude oil production (base case vs. tariff case)



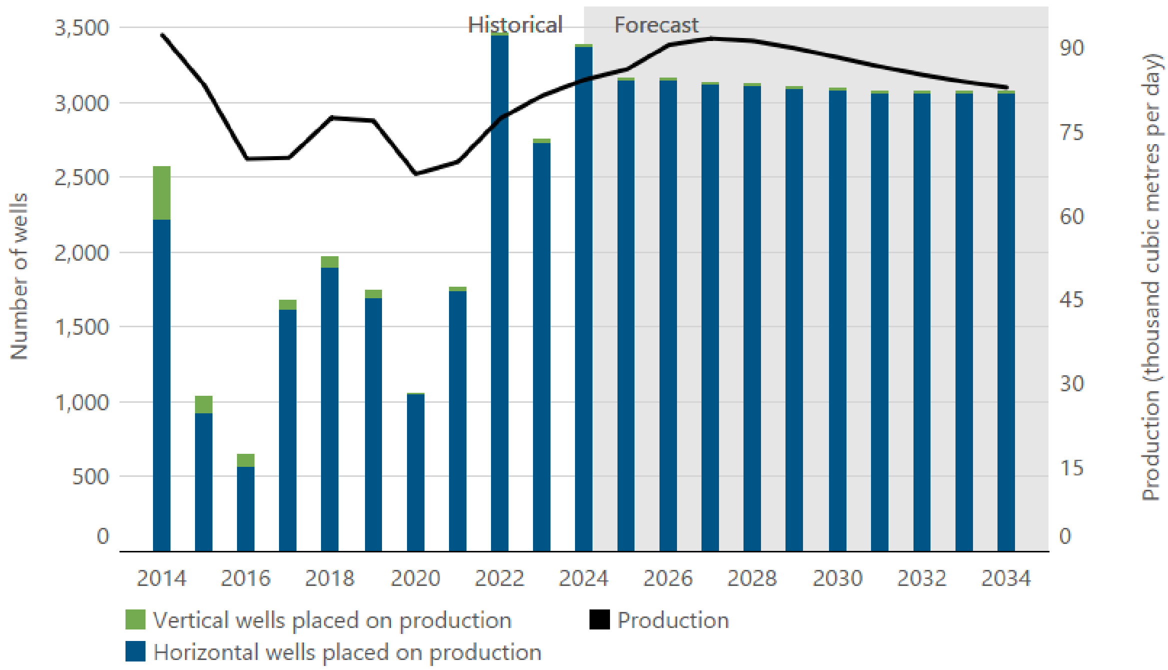
4.4 Crude Oil Well Activity

4.4.1 Summary

The number of new wells placed on production increased by 23% in 2024. Despite a slight drop in oil prices, mature basins, and elevated costs, well activity increased, most notably in PSAC areas 4 and 7. Lower interest rates and improved drilling efficiency supported continued drilling in highly productive formations. Over the base case forecast period, the number of new wells placed on production will hover above 3000 per year. However, continued capital discipline paired with inflationary pressures are expected to constrain future drilling activity. The decline in drilling is mild and gradual over the forecast period and stabilizes by 2034, with new well counts expected to remain well above 2023 levels.

Figure S4.4 shows the average daily production of crude oil and the number of new wells placed on production.

Figure S4.4 Alberta average daily production and number of crude oil wells placed on total production



Note: The wells placed on production include legs and recompletions.

4.4.2 Well Activity in 2024

In 2024, 3385 new crude oil wells were placed on production compared with 2760 in 2023. Despite slightly lower commodity prices and inflated capital and operating costs, prices remained well above 2021 levels supporting drilling activity through 2024. Lower interest rates and access to high-productivity formations (the Cardium and Montney Formations and the Mannville Group) were the primary factors supporting drilling. In 2024, the new wells placed on production comprised

- 15 vertical wells (less than 1% and a 52% decrease from 2023) and
- 3370 horizontal wells (more than 99% and a 23% increase from 2023).

Table S4.1 shows the crude oil production and wells placed on production in 2023 and 2024 and includes the base case forecast to 2034.

Table S4.1 Alberta crude oil production and new wells placed on production highlights

	2023	2024	2025	2026	2034
Crude oil production (10^3 m^3/d)					
Light	45.4	47.5	47.7	49.6	43.4
Medium	12.9	12.0	12.1	12.6	11.5
Heavy	5.9	5.6	5.6	5.8	5.3
Ultra-heavy	17.2	19.2	20.6	22.5	22.8
Total	81.4	84.2	86.1	90.4	82.8
Number of wells placed on production					
Vertical	31	15	20	20	20
Horizontal	2729	3370	3145	3145	3060
Total	2760	3385	3165	3165	3080

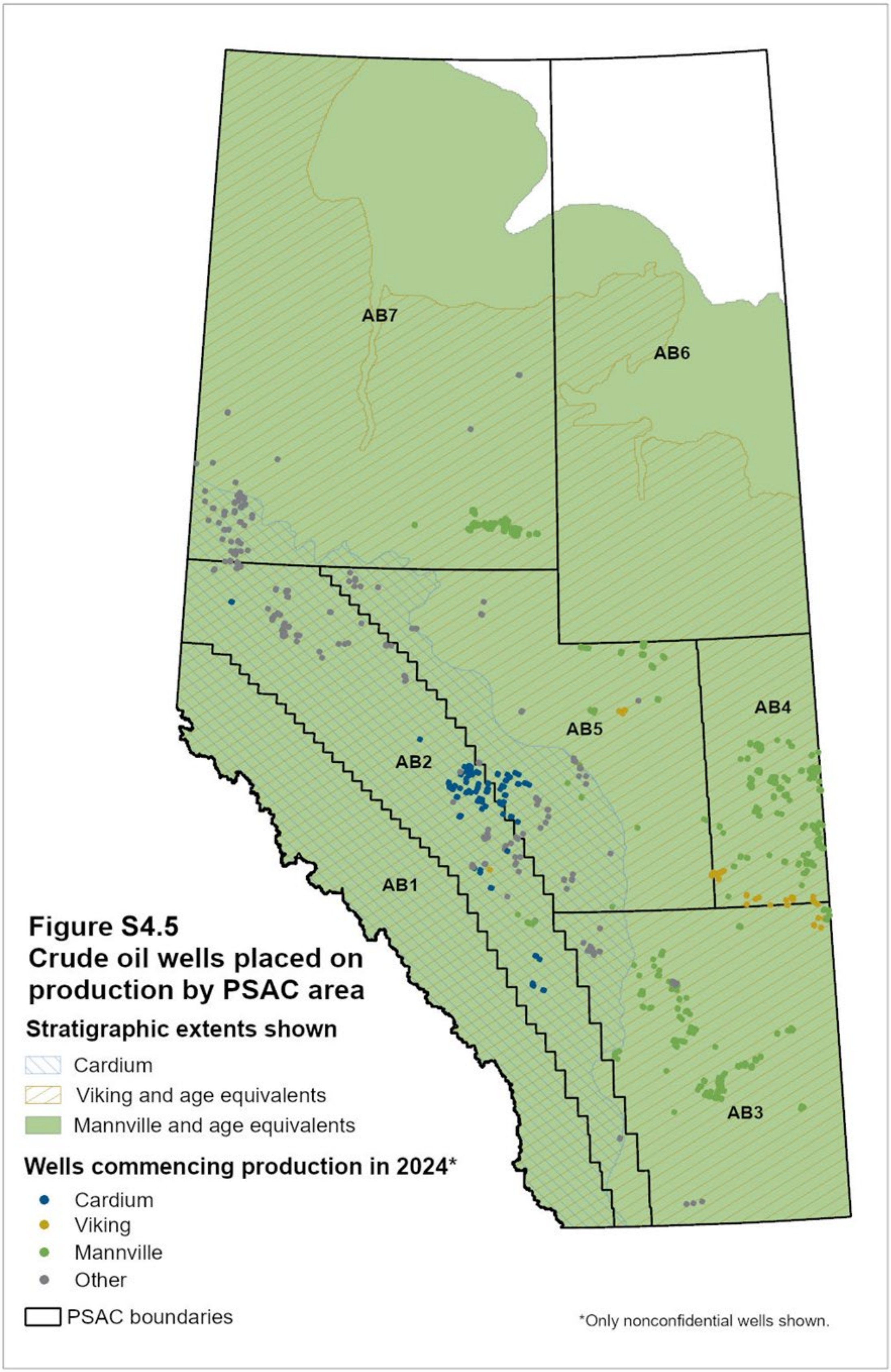
Any discrepanices are due to rounding.

Note: The number of wells placed on production include legs and recompletions.

Producers continued disciplined capital spending, focusing on economic new drilling and reducing debt in 2024. New well investments either targeted high-value light-density crude oil or ultra-heavy crude oil formations requiring lower drilling capital costs.

Despite inflationary pressures, cost reductions continued through advancements in drilling and completion, allowing some producers to drill longer wells in less time at a lower cost per metre. For horizontal wells using hydraulic multistage fracturing, the increased fracturing stages per well and multiple lateral legs resulted in higher production and slower decline rates.

Figure S4.5 shows the wells placed on production in 2024 by PSAC area and their distribution in the Cardium Formation, Viking Formation, and Mannville Group.


AB7
AB6
AB5
AB4
AB2
AB1
AB3
Figure S4.5
Crude oil wells placed on production by PSAC area
Stratigraphic extents shown
Cardium
Viking and age equivalents
Mannville and age equivalents
Wells commencing production in 2024*
Cardium
Viking
Mannville
Other
PSAC boundaries
*Only nonconfidential wells shown.

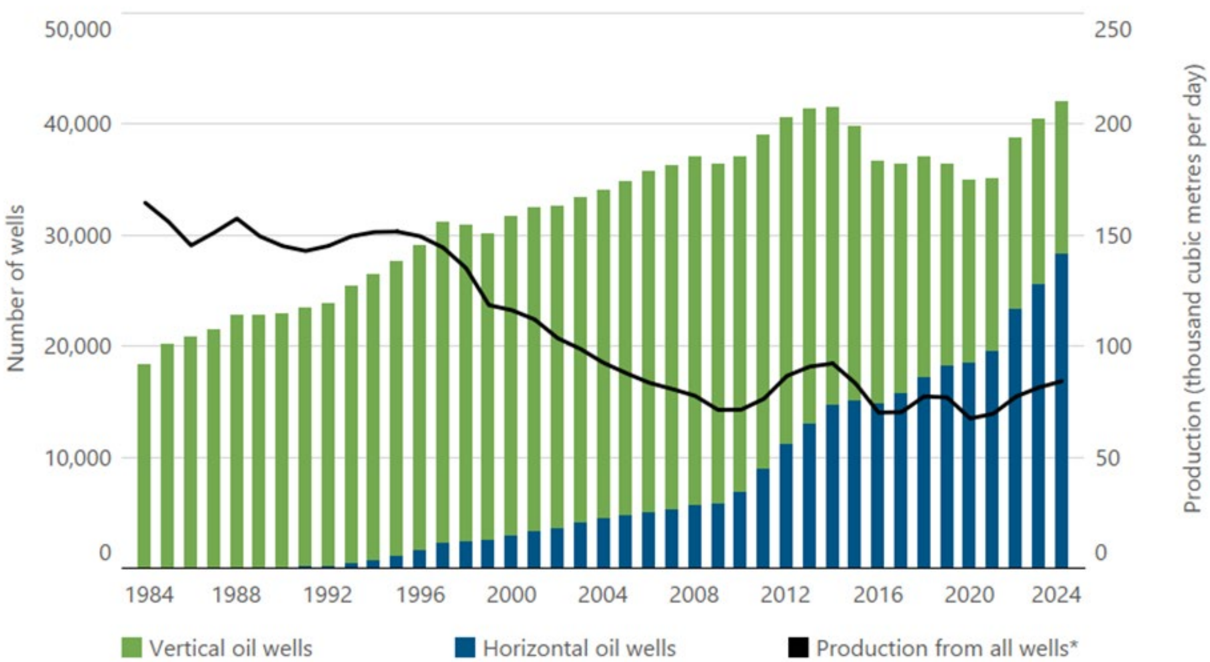
4.4.3 Base Case Forecast for 2025 to 2034

Between 2025 and 2034, the average number of new oil wells placed on production is expected to be around 3100 per year. However, in the near term, more favourable prices will result in better profit margins and slightly higher well activity. Producers will continue targeting light crude oil and ultra-heavy crude oil formations with better economic returns. Drilling activity is expected to remain robust in PSAC 4 and 7.

Figure S4.6 shows the historical trend between average daily production and the number of wells producing crude oil in Alberta.

Table S4.2 shows the number of new crude oil wells placed on production by PSAC area and includes the base case forecast to 2034.

Figure S4.6 Average daily production and number of producing wells for Alberta crude oil



* Production includes oil production from gas wells.

Table S4.2 Alberta new crude oil wells placed on production by PSAC area

Year	PSAC 1[a] Foothills	PSAC 2[a] Foothills Front	PSAC 3 Southeastern Alberta	PSAC 3	PSAC 4 East Central Alberta	PSAC 4	PSAC 5[a] Central Alberta	PSAC 6[ab] Northeastern Alberta	PSAC 7 Northwestern Alberta	PSAC 7
	horizontal	horizontal	vertical	horizontal	vertical	horizontal	horizontal	horizontal	vertical	horizontal
2001	7	235	303	172	460	73	384	0	278	54
2002	3	168	260	296	365	45	300	0	236	30
2003	10	281	342	408	446	128	355	1	261	30
2004	8	286	223	267	498	96	381	1	223	42
2005	18	286	235	262	395	56	359	0	302	66
2006	17	376	218	158	448	65	364	7	289	77
2007	7	243	206	174	415	142	302	4	255	60
2008	4	291	242	163	370	118	334	9	246	82
2009	1	137	161	147	261	73	178	5	93	40
2010	2	386	213	242	316	187	525	0	141	153
2011	6	722	241	288	357	331	740	1	107	291
2012	16	839	215	301	246	322	777	2	72	329
2013	15	794	114	298	254	323	622	3	45	271
2014	22	721	59	335	186	386	518	0	52	289
2015	0	325	21	192	53	141	167	0	22	119
2016	0	138	16	128	35	105	165	0	18	49
2017	2	309	28	247	25	434	391	0	18	229
2018	0	389	27	381	27	492	282	5	19	345
2019	0	290	13	421	29	395	252	8	16	321
2020	0	156	5	206	2	185	220	1	7	279
2021	1	287	9	180	15	387	392	0	5	489
2022	0	366	5	342	4	670	886	0	11	1182
2023	0	345	6	274	15	691	464	< 5	10	955
2024	0	295	0	330	10	880	620	< 5	5	1245
2025	0	285	5	315	10	720	610	< 5	5	1215
2026	0	285	5	320	10	710	615	< 5	5	1215
2027	0	280	5	315	10	695	620	< 5	5	1205
2028	0	275	5	315	10	685	630	< 5	5	1200
2029	0	270	5	315	10	675	630	< 5	5	1195
2030	0	270	5	310	10	670	630	< 5	5	1195
2031	0	270	5	305	10	670	625	< 5	5	1190
2032	0	275	5	305	10	675	620	< 5	5	1185
2033	0	280	5	305	10	680	615	< 5	5	1180
2034	0	285	5	305	10	685	605	< 5	5	1180

[a] Majority of wells are horizontal.

[b] PSAC Area 6 overlaps with the Athabasca Oil Sands Area boundary and does not have significant activity.

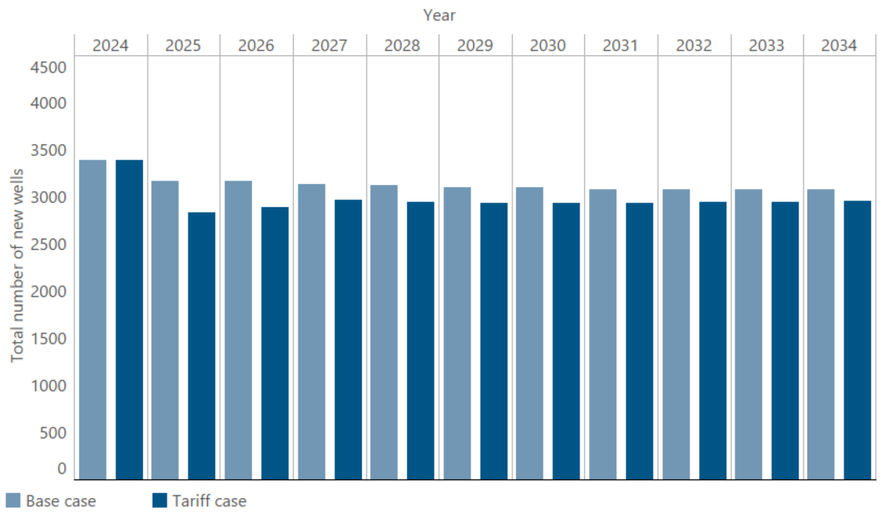
4.4.4 One-Year Tariff Scenario (Tariff Case)

The tariff case projects fewer new wells placed on production across the forecast period. As tariffs reduce prices, increase costs, and erode Alberta's comparative advantage, the number of new wells drilled is expected to fall below the base case despite a similar forecast trajectory.

An estimated 2835 new wells will be drilled in 2025, a 10% reduction from the base case. Throughout the forecast period, new wells drilled will remain stable above 2023 levels settling around 2950 per year, averaging 6% below the base case. New wells drilled do not rebound to base case levels due to forgone investment early in the forecast and lower oil prices inhibiting new drilling rates and profitability over the forecast period.

Figure S4.7 shows the number of new crude oil wells placed on production in both the base case and tariff case forecasts.

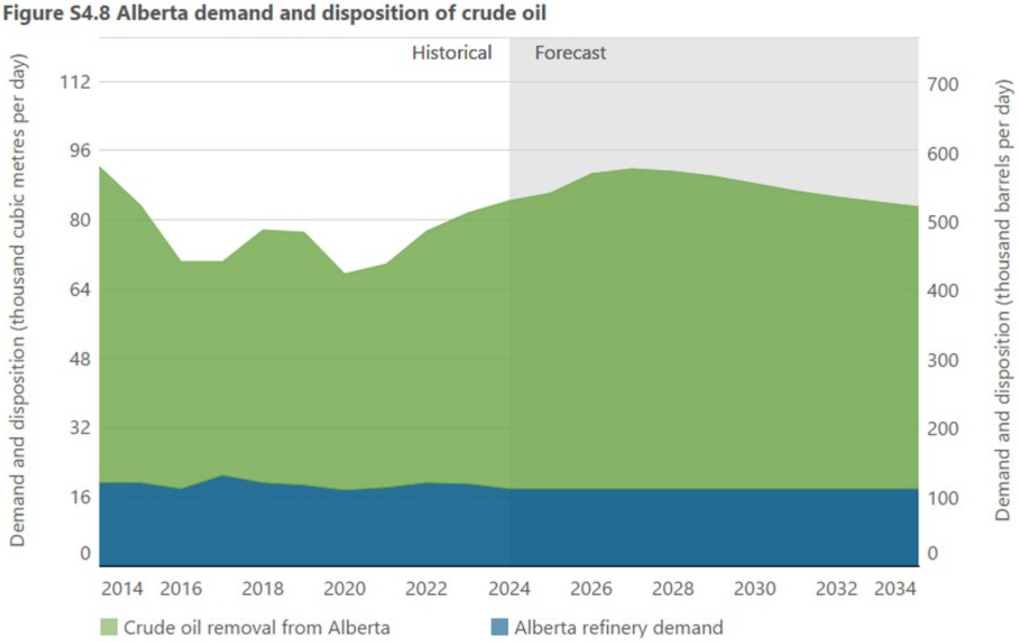
Figure S4.7 Alberta total number of new crude oil wells placed on total production (base case vs. tariff case)



4.5 Crude Oil Demand

Figure S4.8 shows the demand history and forecast for Alberta refineries and removal of crude oil from Alberta.

Figure S4.8 Alberta demand and disposition of crude oil



4.5.1 Demand

4.5.1.1 In 2024

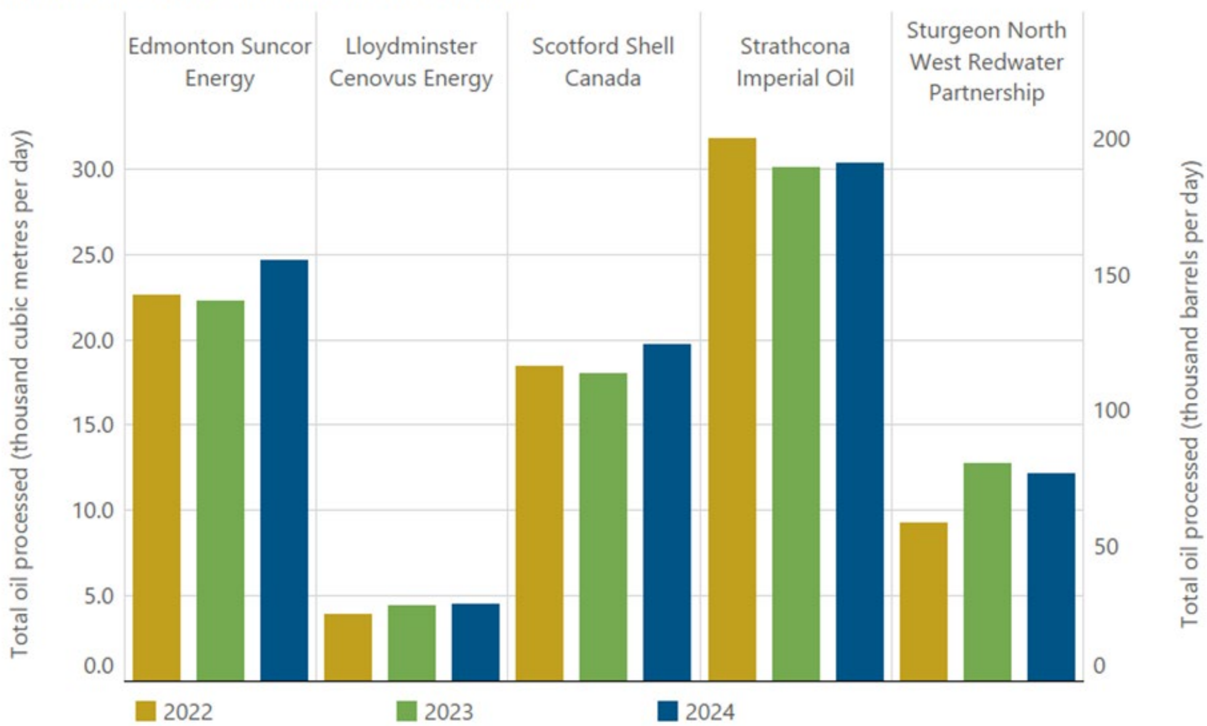
Alberta experienced slightly weakened crude oil demand in 2024, which aligns with weaker economic growth nationally and unexpected refinery closures caused by extreme weather emergencies. Alberta's demand for crude oil decreased from 18.8 10^3 m^3/d or 118.6 10^3 bbl/d in 2023 to 17.8 10^3 m^3/d (112.3 10^3 bbl/d) in 2024.

Figure S4.9 shows the 2024 throughput volumes for Alberta's operating refineries, with a total throughput of 91.4 10^3 m^3/d (575.0 10^3 bbl/d) crude oil equivalent. This represents a 103% utilization rate of refinery capacity.

The total throughput consisted of

- 25% crude oil and pentanes,
- 62% synthetic crude oil, and
- 13% nonupgraded bitumen.

Figure S4.9 Oil processed at Alberta refineries



4.5.1.2 Base Case Forecast for 2025 to 2034

Alberta's crude oil demand is expected to remain steady from 2025 to 2034, holding at 17.8 10^3 m^3/d (112.3 10^3 bbl/d). This stability is attributed to the absence of new refineries or significant refinery expansions in Alberta, signalling a sustained demand for crude oil.

4.5.2 Removals

4.5.2.1 In 2024

In 2024, removals increased by 6.1% to 66.4 10^3 m^3/d (417.7 10^3 bbl/d), with growth primarily driven by the 5% fall in Alberta refinery demand as production growth persisted. Oil not refined in Alberta refineries is assumed to be removed from Alberta. In 2024, removals (upgraded and nonupgraded bitumen plus crude oil and pentanes plus) were 613.8 10^3 m^3/d (3.9 10^6 bbl/d), with crude oil accounting for about 10%.

4.5.2.2 Base Case Forecast for 2025 to 2034

Growth in removals is expected to continue early into the forecast, growing at an average of 4% until 2027, reaching a peak of 73.7 10^3 m^3/d (464.0 10^3 bbl/d). Mid- and long-term removals are expected to decline by an average of 2% each year, dropping to 65.0 10^3 m^3/d (408.9 10^3 bbl/d) by 2034. This trend aligns with the forecasted decline in crude oil production and anticipated, relatively unchanged crude oil demand in Alberta.

Forecasted changes in crude oil removals are expected to be relatively minor as their share of total production averages 80% throughout the forecast, keeping in balance with Alberta demand. This consistency between Alberta refinery demand and removals suggests increases in pipeline capacity can support growth in production and removals early in the forecast.

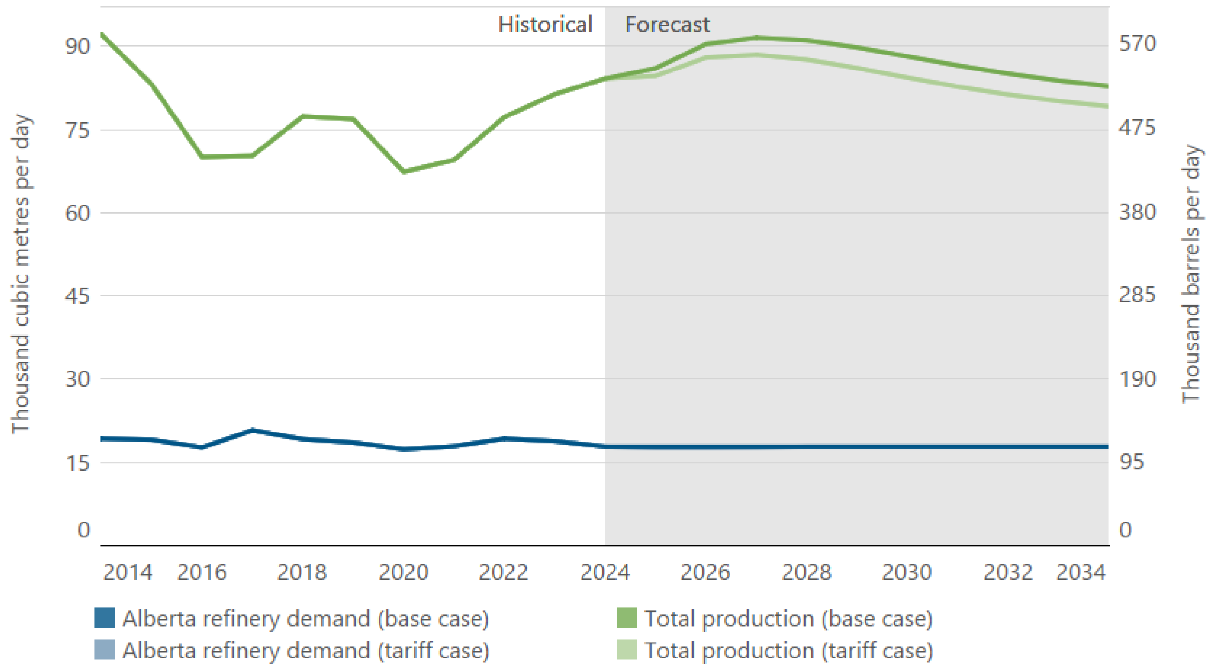
4.5.2.3 One-Year Tariff Scenario (Tariff Case)

Uncertainty and slowed economic activity induced by tariffs are expected to slightly lower Alberta energy consumption and crude oil demand to 17.6 10^3 m^3/d (110.8 10^3 bbl/d). A 1% reduction in 2025 compared with the base case. Despite tariff removal in 2026, demand will remain hindered as economic activity slowly begins to readjust. Demand rebounds in 2027 and reaches the base case level in 2028, with economic activity returning to normal and uncertainty being eased.

Moreover, removals are expected to fall by 2% to 67.0 10^3 m^3/d (421.7 10^3 bbl/d) compared with the base case in 2025, as reduced production and drilling activity hinder exports despite the declined domestic demand. Although tariffs are removed in 2026, the forgone drilling activity and reduced production will suppress growth. Removals will remain an average of 5% below the base case estimates across the forecast.

Figure S4.10 shows the difference in production, demand, and removals between the base case and tariff case forecasts.

Figure S4.10 Alberta crude oil production, demand, and removals* (base case vs. tariff case)



*The difference between supply and demand are removals.

4.6 Crude Oil Supply Costs

The supply cost of a resource project is the minimum constant dollar price needed to recover all capital expenditures, operating costs, royalties, taxes, and earn a specified return on investment. Supply costs indicate whether a project is economically viable.

The most effective and cost-efficient completion technology used depends on the underlying geology. Supply costs vary significantly for different geological plays and the PSAC areas because of

- differing production rates,
- well types,
- drilling and operating costs, and
- royalties.

Wells with a longer total measured depth, typically horizontal wells, tend to have higher initial productivity, but also higher capital costs. However, the higher initial productivity of these wells will usually offset the higher capital costs, resulting in lower supply costs.

Wells drilled in the following PSAC areas tend to be horizontal and typically have higher initial productivity:

- Foothills Front (PSAC 2)
- Central Alberta (PSAC 5)
- Northwestern Alberta (PSAC 7)

4.6.1 Supply Costs by PSAC Area

Table S4.3 shows the estimated supply costs for crude oil by PSAC area. These costs are based on 2024 capital and operating costs and representative production profiles. Companies often drill more than one well or lateral leg from a well pad (commonly referred to as a multiwell pad or multilateral well). These wells take advantage of economies of scale and typically incur lower capital costs, resulting in a lower cost per unit of output.

Supply costs in 2024 increased by an average of 6% from 2023 due to lower initial productivity rates in PSAC areas 2, 4, 5, and 7 and increased capital and operating costs. Estimated drilling, casing, and completion costs increased across all PSAC areas. Higher associated drilling costs, such as service rigs, labour, production casing and cementing, completion fluids, fracture stimulation, transportation, and equipment rentals, also contributed to higher supply costs.

4.6.2 One-Year Tariff Scenario (Tariff Case)

Due to the addition of a tariff scenario to this year's publication, supply costs for single wells and multi well pads contain an upper and lower cost estimate in Table S4.3. The lower bound represents the base case cost estimate and the upper bound represents the tariff case cost estimate. Tariffs are assumed to last for one year, increasing the costs of key inputs related to oil and gas drilling and production.

Table S4.3 Alberta crude oil supply costs by PSAC area, 2024

Area	Formation	Type of well	Type of oil	Total measured depth	Initial productivity	Total capital cost	Fixed operating cost	Variable operating cost	Crude oil supply cost- single well	Crude oil supply cost- multiwell pad with 4 wells
				(m)	(m3/d)	(Cdn$000)	(Cdn$000/year)	(Cdn$/m3)	(Cdn$/bbl)	(Cdn$/bbl)
PSAC 2	Cardium	Horizontal	Sweet light	3,900	14.9	3,738	86.70	53.67	44.64 - 46.11	38.82 - 40.13
PSAC 2	Cardium	Horizontal	Sweet medium	3,600	5.6	4,006	71.37	61.57	79.56 - 82.58	67.46 - 69.83
PSAC 2	Spirit River	Horizontal	Sweet light	4,230	30.7	6,789	75.95	53.67	56.27 - 58.41	46.71 - 48.43
PSAC 3	Sunburst	Vertical	Sweet medium	1,540	2.5	1,140	45.16	96.69	53.38 - 54.84	n/a
PSAC 3	Banff	Horizontal	Sour medium	3,800	15.1	6,047	36.56	101.43	76.75 - 79.73	66.13 - 68.82
PSAC 3	Viking	Horizontal	Sweet medium	2,000	6.0	1,554	24.04	31.96	33.72 - 35.01	30.73 - 31.88
PSAC 4	Lloyd SS	Vertical	Sweet heavy	1,100	3.2	1,515	78.90	74.99	57.84 - 59.48	n/a
PSAC 4	Sparky SS	Horizontal	Sweet heavy	1,600	3.2	1,837	78.90	74.99	65.38 - 67.30	54.87 - 56.46
PSAC 5	Rock Creek	Horizontal	Sweet medium	2,300	5.3	2,720	71.72	50.12	91.01 - 93.85	78.63 - 80.96
PSAC 5	Cardium	Horizontal	Sweet light	3,800	16.4	3,400	86.70	53.67	47.33 - 48.87	40.16 - 41.38
PSAC 7	Gilwood	Vertical	Sweet light	1,770	3.6	1,895	80.65	92.35	55.1 - 56.42	n/a
PSAC 7	Keg River	Horizontal	Sweet light	2,050	6.9	3,819	216.40	27.63	61.28 - 62.94	53.85 - 55.05
PSAC 7	Beaverhill Lake	Directional	Sweet light	2,500	2.7	2,788	80.65	92.35	89.37 - 92.29	n/a
PSAC 7	Montney	Horizontal	Sweet light	4,000	27.5	6,383	88.65	104.98	44.17 - 45.49	38.38 - 38.97

Note: Cost data from petroCUBE and the Enserva Well Cost Study Winter 2024 have been used to estimate the supply costs.

4.7 Crude Oil Methodology

4.7.1 Production Forecast

The AER forecasts for production and well activity are available by PSAC areas, crude oil density, and well type.

The AER does not separate low-permeability oil production from conventional crude oil production. It is often difficult or impossible to separate the tight portion of the reserve or tight oil production from a reservoir. Therefore, any tight oil volumes are included within the AER's crude oil reserves and production reporting.

Crude oil production is forecast by density and well type. In Alberta, crude oil is oil produced outside the oil sands areas or, if within the oil sands areas, from formations other than the Mannville and Woodbend Groups. Crude oil is classified by density into the following categories:

- ultra-heavy crude oil (density is greater than or equal to 925 kilograms per cubic metre [kg/m^3])
- heavy crude oil (density is greater than or equal to 900 kg/m^3 and less than 925 kg/m^3)
- medium crude oil (density is greater than or equal to 850 kg/m^3 and less than 900 kg/m^3)
- light crude oil (density is less than 850 kg/m^3)

4.7.2 Forecasting Crude Oil Production

In forecasting crude oil production, the following variables are incorporated (see Table S4.2).

- expected production from existing wells,
- the number of new wells placed on production,

- the average initial productivity of the new wells, and
- production decline rates of the new wells.

We use a model that considers prices, royalties, taxes, capital costs, carbon price, and other costs. The model calculates a net present value for representative wells (wells exhibiting average initial productivity rates, length, depth, decline rates, and other characteristics common to an area) for all years within the forecast period, which forms the basis of the forecast. The forecast considers limiting factors such as current and future capital market conditions and remaining reserves.

4.7.2.1 Initial Productivity Rates

Table S4.4 shows the forecast initial productivity using updated average rates for new wells by PSAC area.

Table S4.4 Forecast initial productivity for new Alberta crude oil wells (m^3/d)

Year	PSAC 1[a]	PSAC 2[a]	PSAC 3	PSAC 3	PSAC 4	PSAC 4	PSAC 5[a]	PSAC 6[abc]	PSAC 7	PSAC 7
	Foothills	Foothills Front	Southeastern Alberta		East Central Alberta		Central Alberta	Northeastern Alberta	Northwestern Alberta	
	horizontal	horizontal	vertical	horizontal	vertical	horizontal	horizontal	horizontal	vertical	horizontal
2023	5.3	16.8	0.3	8.9	3.5	4.3	8.7	n/a	5.6	7.9
2024	5.3	17.5	0.3	8.9	3.5	3.1	6.5	n/a	5.6	7.9
2025	5.3	17.2	0.3	8.9	3.5	3.1	6.4	n/a	5.5	7.8
2026	5.3	17.1	0.3	8.8	3.5	3.1	6.2	n/a	5.5	7.8
2027	5.2	17.0	0.3	8.8	3.5	3.1	6.1	n/a	5.5	7.7
2028	5.2	17.0	0.3	8.8	3.4	3.1	6.1	n/a	5.5	7.6
2029	5.2	16.9	0.3	8.7	3.4	3.0	6.1	n/a	5.5	7.6
2030	5.1	16.8	0.3	8.7	3.4	3.0	6.0	n/a	5.4	7.5
2031	5.1	16.7	0.3	8.7	3.4	3.0	6.0	n/a	5.4	7.4
2032	5.1	16.7	0.3	8.6	3.4	3.0	6.0	n/a	5.4	7.3
2033	5.1	16.6	0.2	8.6	3.4	3.0	6.0	n/a	5.4	7.3
2034	5.1	16.5	0.2	8.6	3.4	3.0	6.0	n/a	5.4	7.2

[a] Majority of wells are horizontal.
[b] PSAC Area 6 overlaps with the Athabasca Oil Sands Area boundary and does not have significant activity.
[c] Not available (n/a).

4.7.2.2 Decline Rates

Assumed decline rates in Table S4.5 will vary depending on such factors as the well's age, type, and geological location.

Table S4.5 Forecast decline rates for new Alberta crude oil wells

Year	PSAC 1[a]	PSAC 2[a]	PSAC 3	PSAC 3	PSAC 4	PSAC 4	PSAC 5[a]	PSAC 6[a]	PSAC 7	PSAC 7
	Foothills	Foothills Front	Southeastern Alberta		East Central Alberta		Central Alberta	Northeastern Alberta	Northwestern Alberta	
	horizontal	horizontal	vertical	horizontal	vertical	horizontal	horizontal	horizontal	vertical	horizontal
Year 1	-43%	-56%	-21%	-42%	-14%	-32%	-41%	-14%	-40%	-48%
Year 2	-13%	-39%	-11%	-34%	-13%	-32%	-34%	-7%	-31%	-39%
Year 3	-8%	-34%	-11%	-31%	-7%	-20%	-26%	-5%	-23%	-29%
Year 4	-8%	-32%	-11%	-32%	-17%	-19%	-25%	-4%	-31%	-30%
Years 5–9	Unchanged	Gradual Decline	Gradual Decline	Gradual Decline	Gradual Decline	Gradual Decline	Gradual Decline	Unchanged	Unchanged	Gradual Decline
Year 10	-7%	-10%	-3%	-1%	-5%	-10%	-10%	-4%	-10%	-10%

[a] Majority of wells are horizontal.

4.7.3 Crude Oil Production Forecast Accuracy

The crude oil production forecasts have been reasonably accurate over the past 5 years. The forecast deviation from the 2024 actual crude oil production ranged from 2% in the 2023 report to 20% in the 2020 report. The high deviation from the 2020 forecast was primarily due to the uncertainty surrounding the global economic pandemic and the trajectory of economic recovery thereafter.

4.7.4 Demand Forecast

The Alberta crude oil demand forecast is based on historical refinery throughput, anticipated new refineries, and expansions to current refinery capacity.

Removals: Removals are the difference between Alberta production and Alberta demand.

Refinery throughput: The AER uses historical utilization rates when forecasting refinery throughput in Alberta.

4.7.5 Supply Cost

The following data were used to derive a supply cost estimate for the average horizontal or vertical/directional well in each PSAC area:

- the formation
- initial productivity
- production decline rates
- vertical depth
- total measured depth
- gas composition
- capital costs (drilling, casing, completion, and land acquisition)
- operating costs (processing and transportation)

- royalties
- taxes
- a 10% nominal rate of return

The supply costs are not risked (i.e., assumes a 100% success rate in drilling) and are estimated as wellhead costs, which are reported in Canadian dollars.

The AER defines a supply cost as the minimum constant dollar price needed to recover all capital costs, operating costs, royalties, taxes, and earn a specified return on investment. The supply cost calculation determines a dollar value required per unit of production.

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 costs, operating costs, royalties, and other factors. Therefore, the results may not reflect wells that differ from the representative well profiles used in the analysis.

4.7.6 Data

All 2024 data are reported by industry until the end of December and do not include any subsequent amendments. We used crude oil production volumes submitted to Petrinex.

5 Natural Gas

5.1 Highlights of 2024

Production: Although natural gas prices were lower during 2024, production of marketable natural gas was 315.7 million cubic metres per day (10^6 m^3/d) or 11.2 billion cubic feet per day (Bcf/d). This volume was a marginal increase from 2023 production driven by higher shale gas and gas production from oil wells. Conventional and coalbed methane production volumes, however, remained similar to 2023.

By 2034, marketable production is anticipated to grow to 330.1 10^6 m^3/d (11.7 Bcf/d) in the base case. Increasing output from the Petroleum Services Association of Canada (PSAC) areas of Foothills Front, Northwestern Alberta, and shale is expected to outweigh decreasing production in other parts of the province.

Number of wells: The number of new wells placed on production in 2024 decreased by 12.1% to 810. A significant decline in natural gas prices and higher inventories in 2024 resulted in fewer new wells placed on production.

The number of new wells each year is expected to increase over the forecast period. By 2034, 1130 new gas wells are expected to be placed on production in the base case. Most of the new wells will be horizontal multistage fractured wells targeting high-productivity, liquids-rich formations in the western regions of Alberta (Foothills Front and Northwestern Alberta) and shale gas.

Demand: Alberta’s demand for natural gas was estimated at 194.3 10^6 m^3/d (6.9 Bcf/d) in 2024 (about 62% of marketable gas production). Demand in 2024 increased by 3.3% from 2023, partly due to higher residential and commercial sector demand.

Alberta’s gas demand in the base case is forecast to be around 67% of its marketable gas production in 2034. Demand is anticipated to increase by 13.3% by 2034, with growth primarily expected from the oil sands, electricity generation, residential and commercial sectors.

5.2 Natural Gas Production

5.2.1 Summary

The average daily production of marketable natural gas in 2024 increased marginally to 315.7 10^6 m^3/d or 11.2 Bcf/d, the highest production level since 2010. The higher production was driven by increases in gas production concentrated in the PSAC Foothills Front (area 2) and Northwestern Alberta (area 7), shale, and gas from oil wells.

In light of the recent re-evaluation of Alberta's natural gas reserves, we anticipate the marketable natural gas production to reach 330.1 10^6 m^3/d (11.7 Bcf/d) by 2034 in the base case. Production increases are expected across the Foothills Front, Northwestern Alberta, and shale. These production gains will likely be partially offset by declines from other areas.

Figure S5.1 shows Alberta's historical average daily marketable gas production and base case forecast by source and PSAC area.

Figure S5.1 Alberta marketable gas average daily production

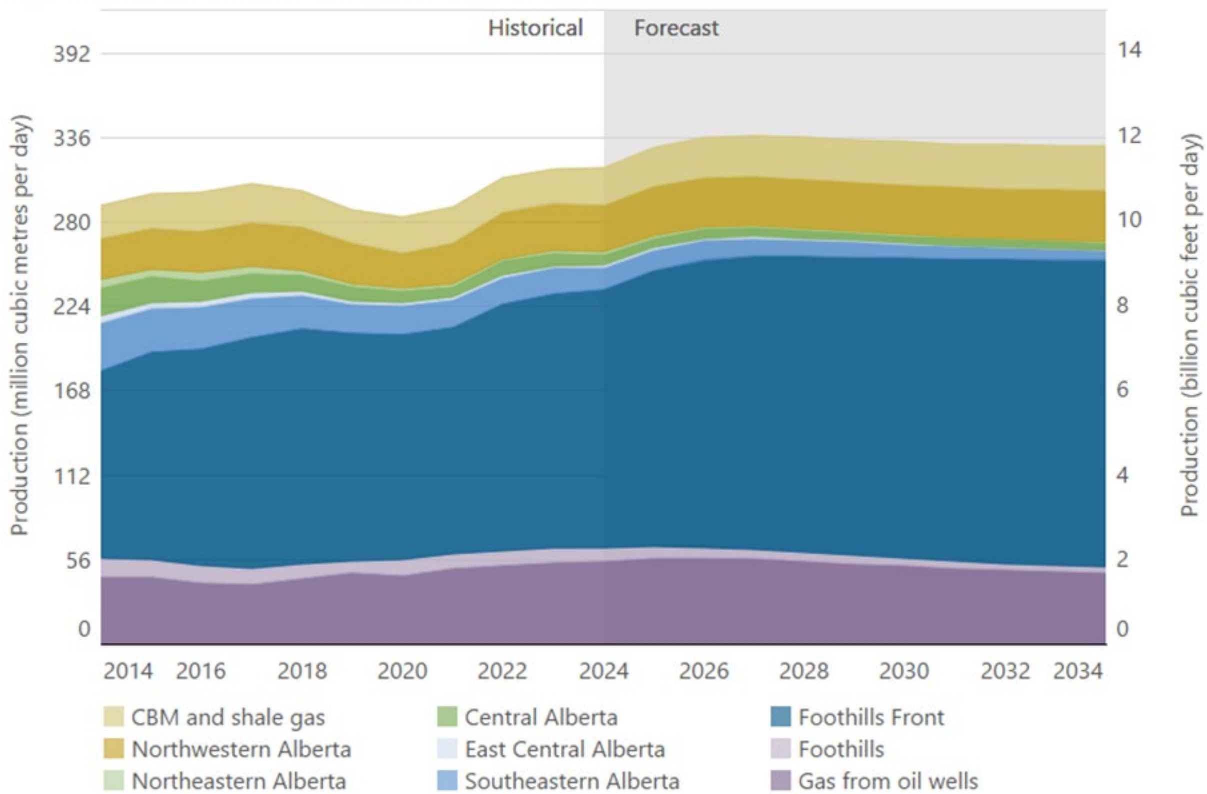


Table S5.1 shows historical numbers and base case forecasts of Alberta's average daily marketable natural gas production and the number of new wells placed on production by year.

Table S5.1 Alberta natural gas production and new wells placed on production highlights

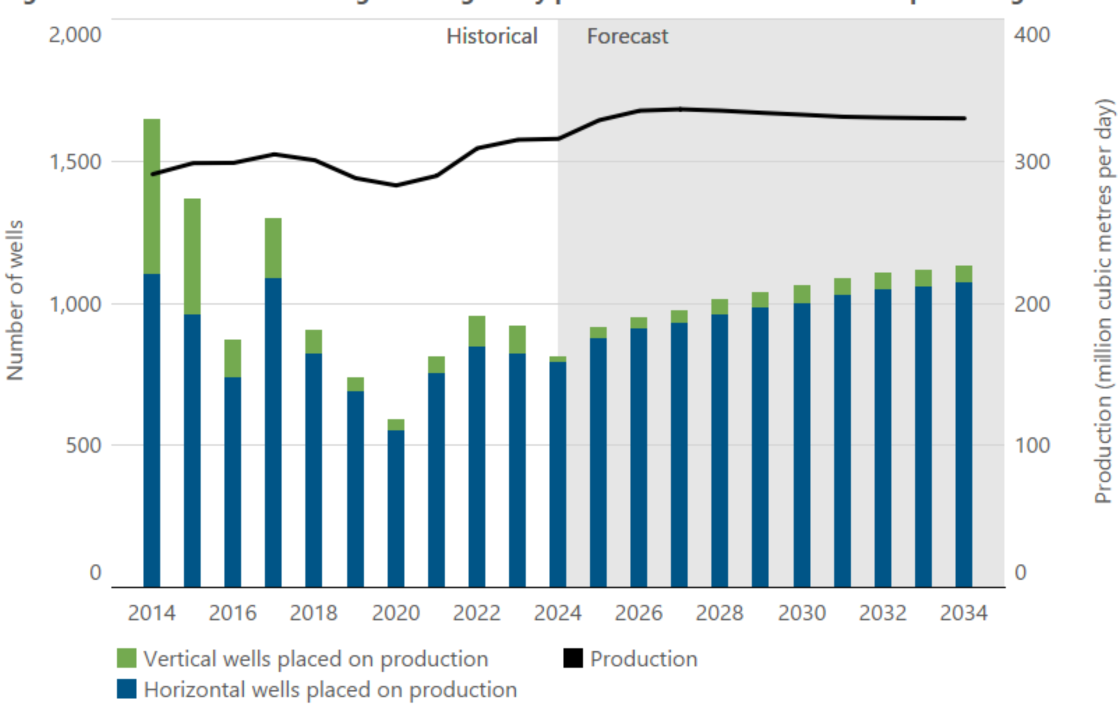
	2023	2024	2025	2026	2034
Marketable production (10^6 m^3/d)					
Gas[a]	292.2	290.6	303.0	308.6	300.7
Coalbed methane	11.9	11.0	10.5	9.9	6.7
Shale	11.0	14.1	15.3	17.0	22.8
Total	315.0	315.7	328.8	335.5	330.1
Number of new wells placed on production					
Vertical	102	18	40	40	60
Horizontal					
Multistage fractured	778	772	855	890	1040
Non-multistage fractured	41	20	20	20	30
Subtotal	819	792	875	910	1070
Total	921	810	915	950	1130

[a] Includes conventional, tight, and gas from oil wells.
Any discrepancies are due to rounding.
Note: The number of wells placed on production include legs and recompletions.

5.2.2 Marketable Gas Production in 2024

Figure S5.2 shows Alberta's average daily production of marketable gas and the number of new producing wells.

Figure S5.2 Alberta marketable gas average daily production and number of new producing wells



Note: The wells placed on production include legs and recompletions.

In 2024, the number of horizontal wells placed on production decreased by 3.3% and the number of vertical wells placed on production by 82.4%. Total conventional (including tight) gas production—defined here as gas production excluding coalbed methane (CBM) and shale gas—decreased marginally by 0.5% in 2024. Shale gas production increased by 28.3%, and gas from oil wells increased by 2.0%. CBM production decreased by 7.7% in 2024.

5.2.3 Tariff Scenarios

Because of significant uncertainty, particularly regarding U.S. tariff policies, this year's report examines two scenarios: a short-term tariff uncertainty scenario (base case) and a one-year tariff scenario (tariff case). The primary difference between these scenarios lies in their tariff assumptions.

- **Base case**: This scenario assumes business as usual and no tariffs. However, the U.S. tariff threats on energy products (oil and gas) persist throughout the first half of 2025 but are ultimately averted through diplomatic negotiations by midyear. Consequently, energy supply and demand are minimally affected.
- **Tariff case**: This scenario assumes a 10% U.S. tariff on energy products (oil and gas) and 25% tariffs on other Canadian goods imposed in the first half of 2025 despite diplomatic efforts. This scenario includes subsequent U.S. and Canadian retaliatory tariffs, other nontariff measures,[9] and additional U.S. tariffs on other trading partners. All tariffs and nontariff measures between Canada and the United States persist until the end of the first quarter of 2026 before mostly being phased out as the review or renegotiation of the Canada-United States-Mexico Agreement. It is expected tariffs will have some long-term effects and structural changes to the global economy (changes in trade and investment flows).

These tariff assumptions affect prices, costs, commodity profitability, investment, supply and demand, project risk factors, and commercial start dates (where applicable) for most chapters of the report, including comparisons of the outcomes of these scenarios.

5.2.3.1 Base Case Forecast for 2025 to 2034

Four trends in natural gas production are expected to continue throughout the forecast period:

- Gas producers will focus on the most productive plays within the province, reducing the need for new wells to maintain production levels compared with past practices.

[9] Nontariff measures can include quotas or restrictions on imported goods (i.e., liquor), export taxes on electricity, and changes in consumer and business behaviour (i.e., buying Canadian).

- Plays rich in natural gas liquids (NGLs) will attract the most attention given their higher profitability, resulting in higher NGL concentrations in the raw gas stream.
- Producers will continue to seek ways to optimize their infrastructure use and lower costs.
- Technological advancements such as drilling horizontal multistage fractured wells will continue to be the prime focus.

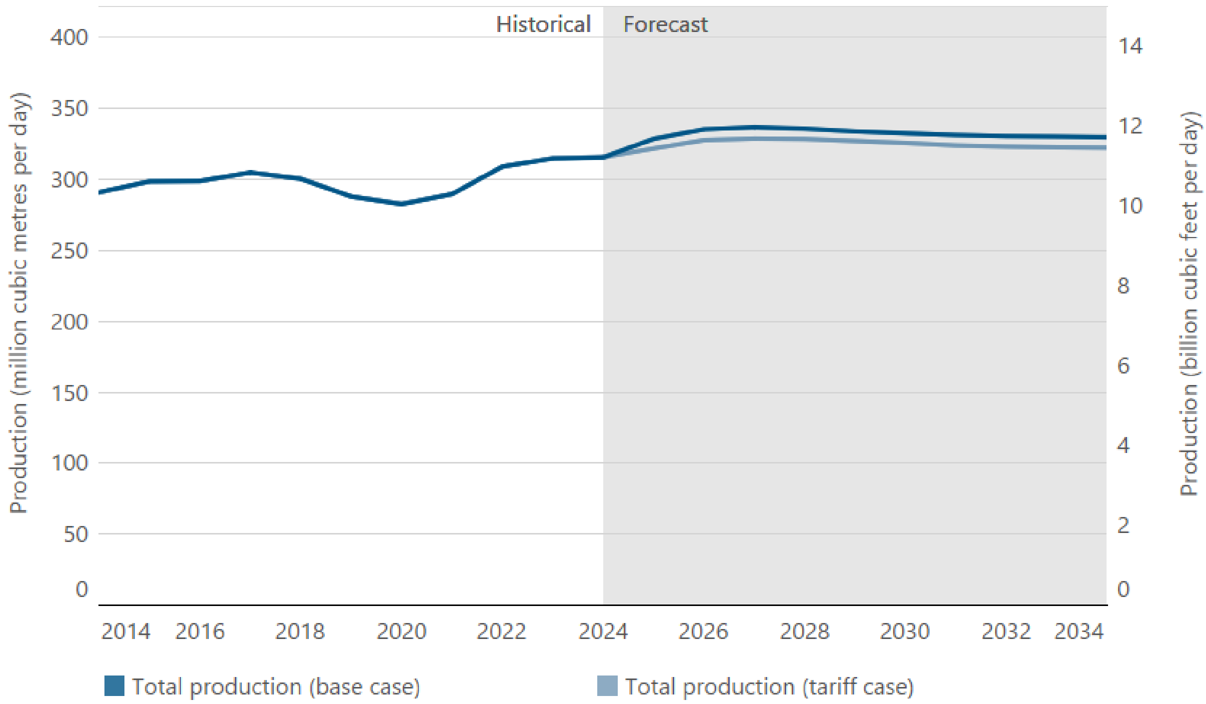
Given these trends, most new natural gas wells in Alberta are expected to come online in the Foothills Front, Northwestern Alberta, and Central Alberta PSAC areas. With growth in new wells placed on production, marketable gas production in Alberta is forecast to grow 4.6% by 2034. This production gain, however, is expected to be mildly offset by declines from other PSAC areas.

5.2.3.2 One-Year Tariff Scenario (Tariff Case)

Under this scenario, the tariffs on the energy sector would reduce natural gas production relative to the base case, as lower regional prices and higher production costs reduce competitiveness. Moreover, these tariffs could lead to a drop in Canadian natural gas exports, particularly to the United States, which can eventually pressure Alberta's production. Despite tariff-related uncertainty and lower investment in the natural gas sector, the effects on production will be relatively small, partly due to reasonable prices over the medium and long term and upcoming planned or under-construction LNG projects in Canada driven by trade diversification. Marketable gas production is expected to decline by 2.1% in 2025 from the base case and will follow a similar trend as the base case thereafter. Natural gas production is expected to reach 322.3 10^6 m^3/d (11.4 Bcf/d) by 2034, 2.4% lower than the base case.

Figure S5.3 shows the forecast total marketable gas production for the two scenarios.

Figure S5.3 Total marketable natural gas production (base case vs. tariff case)

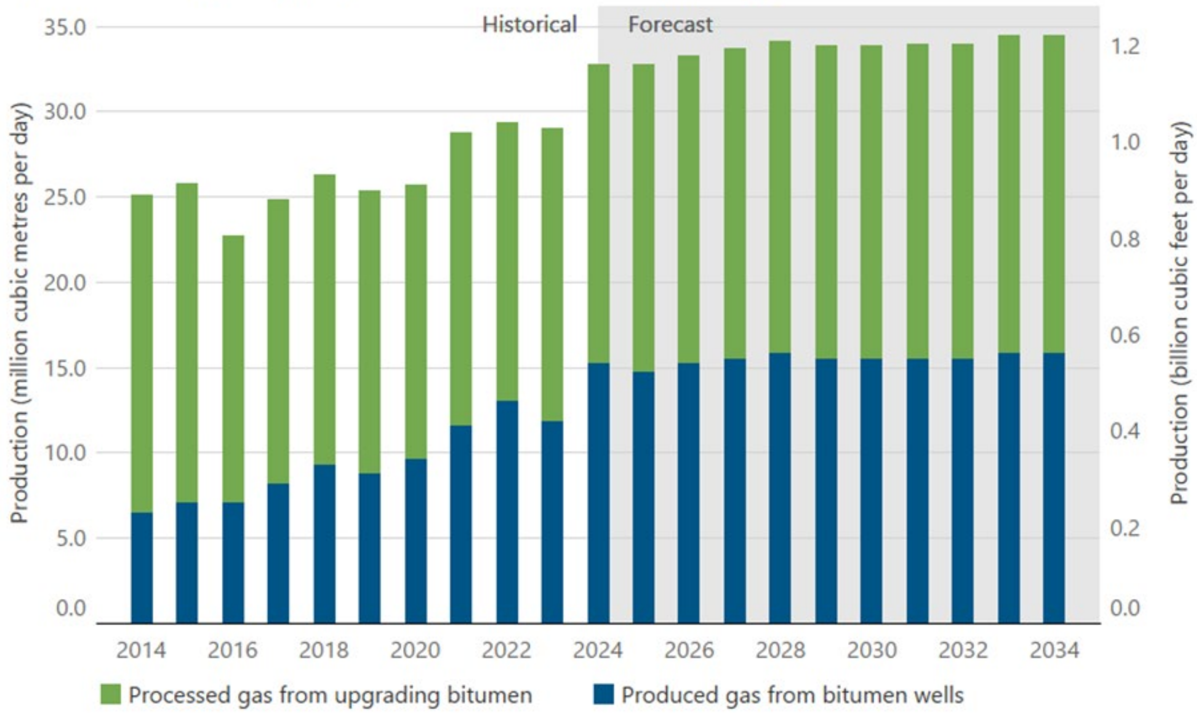


5.2.4 Oil Sands Gas Production and Use

Oil sands operations produce processed gas and produced gas. Processed gas is a by-product of bitumen upgrading, and its composition varies by process (e.g., coking or hydrocracking). Produced gas is raw natural gas from bitumen wells, and its composition varies depending on the source formation. Production trends for these gas sources are driven by bitumen production and upgrading.

Figure S5.4 shows the average daily gas production from bitumen upgrading and wells in the base case.

Figure S5.4 Average daily gas production from bitumen upgrading and bitumen wells

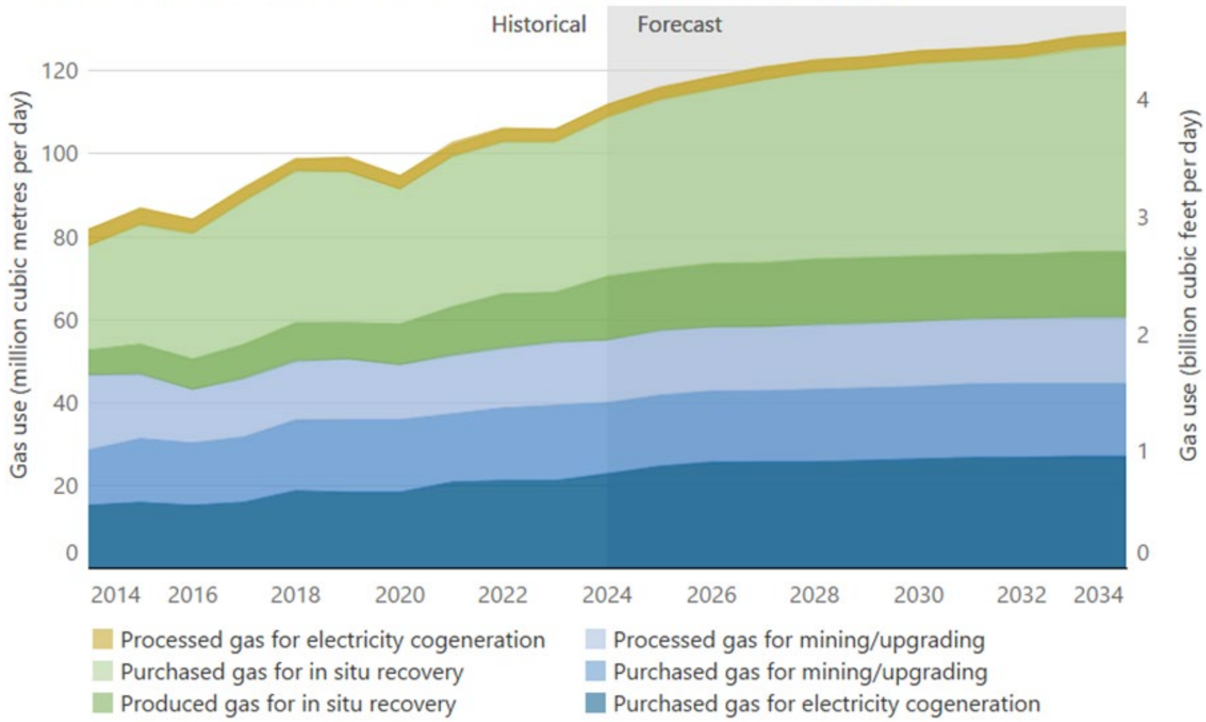


Oil sands operators use processed gas and produced gas for fuel and feedstock to generate electricity, steam, hot water for on-site operations, and hydrogen for upgrading units. Processed gas is also sent to processing facilities to extract high-value liquids.

Operators also purchase large quantities of natural gas from external sources—termed "purchased gas"—for use in their operations. Oil sands operations account for over a quarter of the total natural gas consumption in Alberta (excluding gas used for cogeneration).

Figure S5.5 shows Alberta's total purchased, processed, and produced gas by oil sands operations in the base case.

Figure S5.5 Alberta total purchased, processed, and produced gas by oil sands



5.2.5 Oil Sands Gas Use

5.2.5.1 In 2024

In 2024, the oil sands sector used 111.7 10^6 m^3/d (3.9 Bcf/d) of gas. In mining and upgrading, total gas use decreased by 2.5%, whereas gas use for in situ bitumen recovery processes increased by 10.6%.

5.2.5.2 Forecast for 2025 to 2034

Oil sands gas use is expected to reach 129.1 10^6 m^3/d (4.5 Bcf/d) by 2034, a 15.6% increase from 2024 in the base case. Although total gas use increases align with bitumen production the bulk of the incremental gas use is gas purchased for in situ bitumen recovery. In situ operations use a high volume of natural gas for steam generation, accounting for most of the bitumen production growth in the forecast.

5.2.6 Purchased Gas

Table S5.2 shows the average use rates of purchased gas for oil sands operations in 2024.

Table S5.2 Average use rates of purchased gas for oil sands operations, 2024

Extraction method	Excluding purchased gas for cogeneration		Including purchased gas for cogeneration	
	(m^3/m^3)[a]	(Mcf/bbl)	(m^3/m^3)	(Mcf/bbl)
In situ				
Steam-assisted gravity drainage	199	1.1	232	1.3
Cyclic steam stimulation	220	1.2	291	1.6
Mining with upgrading	138	0.8	199	1.1

Note: Thousand cubic feet (Mcf) and barrels (bbl).

[a] Expressed as either cubic metres of natural gas per cubic metre of bitumen produced or thousand cubic feet of natural gas per barrel of bitumen produced. Rates are an average of typical schemes with sustained production.

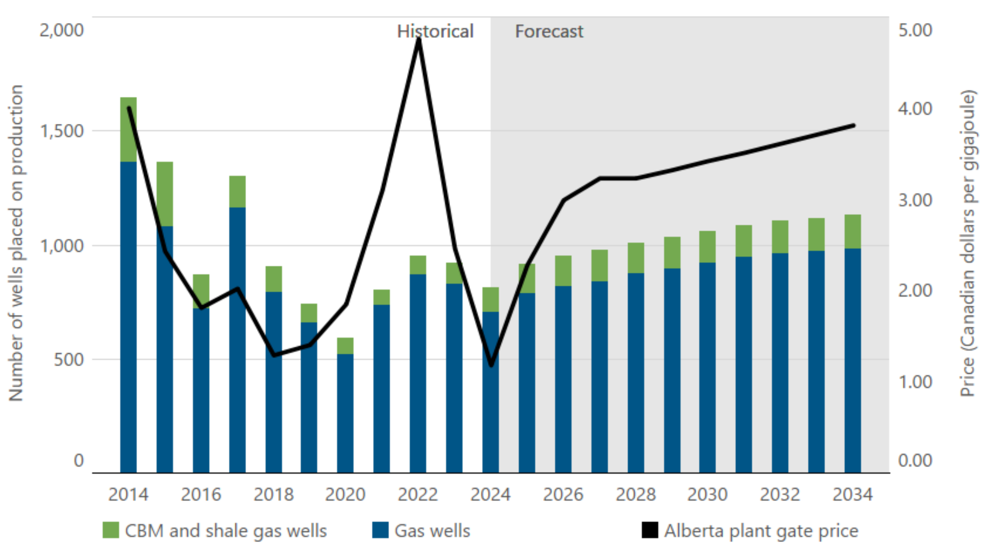
5.3 Natural Gas Well Activity

5.3.1 Summary

The number of new gas wells placed on production in 2024 decreased by 12.1% and included newly drilled wells placed on production and recompletions into new zones of existing wells. A significant decrease in natural gas prices reduced capital spending, while relatively high NGL prices supported drilling activity in the liquids-rich areas.

Figure S5.6 shows the historical numbers and base case forecasts of new natural gas wells placed on production and the Alberta plant-gate price. Well activity is shown by well type in Table S5.1 and by PSAC area in Table S5.3.

Figure S5.6 Alberta natural gas new wells placed on production and price



Note: The wells placed on production include legs and recompletions.

5.3.2 Well Activity in 2024

In 2024, 810 natural gas wells were placed on production in Alberta (Table S5.1). Horizontal wells accounted for 98% of the new wells drilled, of which 97% were completed using horizontal multistage fracturing (HMSF), the dominant technology since 2011. These wells use long horizontal legs to reach across large sections of the gas-bearing formation, increasing their productivity.

Nearly 87% of all new HMSF wells placed on production were in the Foothills Front (PSAC 2) and Northwestern Alberta (PSAC 7). These areas have the highest NGL content in the raw gas stream and the highest productivity rates. About 13% of all new HMSF wells placed on production were in shale formations.

Vertical wells typically target shallower formations with lower NGL content and generally have lower productivity rates than horizontal wells. In 2024, new vertical wells in the province were primarily in Southeastern Alberta (PSAC 3), Central Alberta (PSAC 5), and Foothills Front (PSAC 2). The number of new vertical wells placed on production decreased by 82.4% in 2024 because of the significantly lower price of natural gas last year and the increasing productivity of horizontal wells.

Table S5.1 shows Alberta's average daily marketable gas production and the number of new wells placed on production by year.

Table S5.1 Alberta natural gas production and new wells placed on production highlights

	2023	2024	2025	2026	2034
Marketable production (10^6 m^3/d)					
Gas[a]	292.2	290.6	303.0	308.6	300.7
Coalbed methane	11.9	11.0	10.5	9.9	6.7
Shale	11.0	14.1	15.3	17.0	22.8
Total	315.0	315.7	328.8	335.5	330.1
Number of new wells placed on production					
Vertical	102	18	40	40	60
Horizontal					
Multistage fractured	778	772	855	890	1040
Non-multistage fractured	41	20	20	20	30
Subtotal	819	792	875	910	1070
Total	921	810	915	950	1130

[a] Includes conventional, tight, and gas from oil wells.
Any discrepancies are due to rounding.
Note: The number of wells placed on production include legs and recompletions.

Figure S5.7 shows the distribution of wells starting production in 2024 by PSAC area.

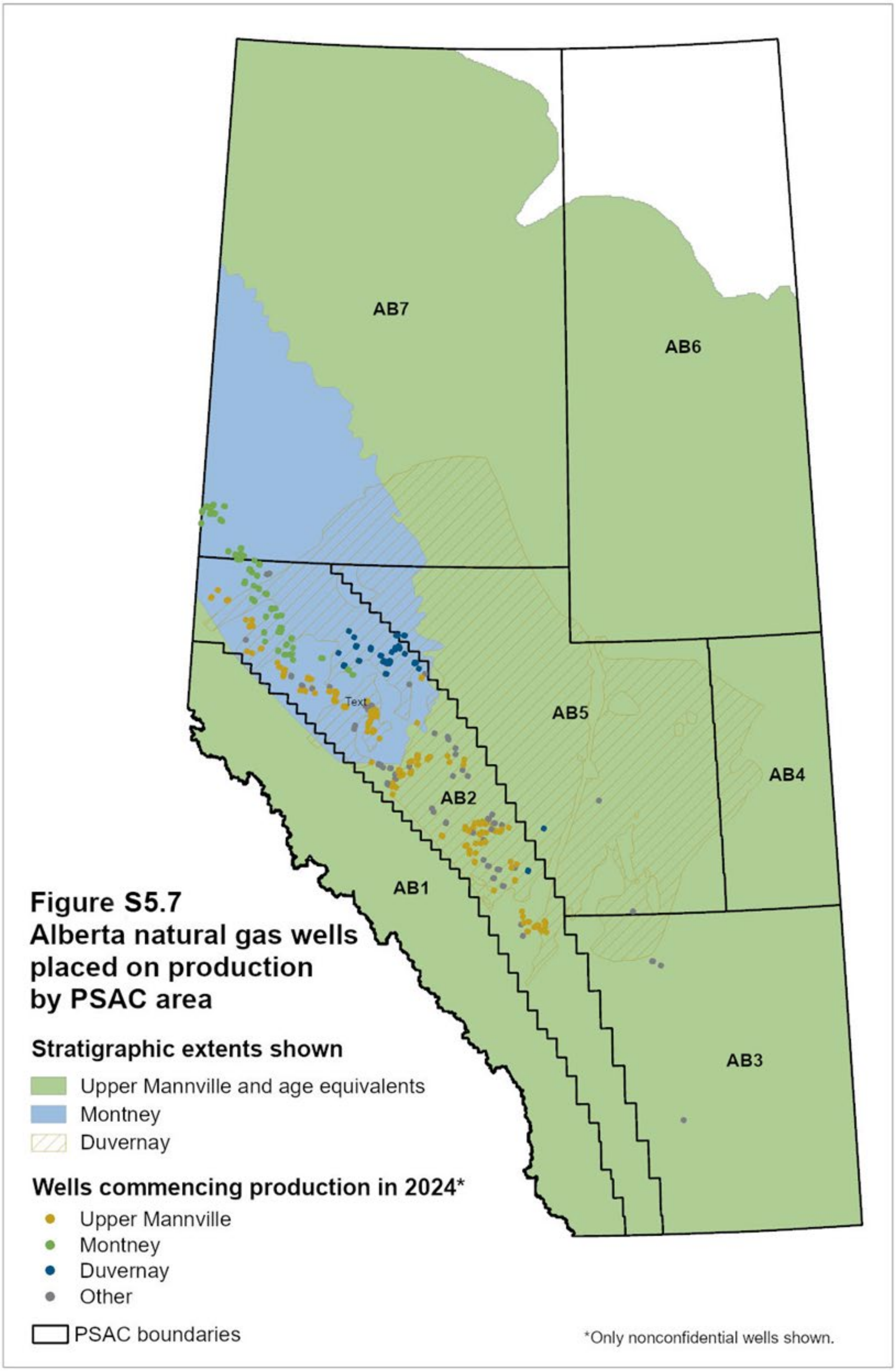


Figure S5.7
Alberta natural gas wells placed on production by PSAC area
AB7
AB6
AB5
AB4
AB2
AB1
AB3
Text
Stratigraphic extents shown
Upper Mannville and age equivalents
Montney
Duvernay
Wells commencing production in 2024*
Upper Mannville
Montney
Duvernay
Other
PSAC boundaries
*Only nonconfidential wells shown.

5.3.3 Base Case Forecast for 2025 to 2034

The number of wells placed on production is expected to increase in 2025 and will keep growing moderately over the forecast period. A recovery in natural gas prices, plus a positive outlook for natural gas demand, will support this increase. We estimate 1130 new wells to be placed on production by the end of the forecast period, representing a 39.5% increase from 2024. Around 92% of the new wells are expected to be HMSF wells concentrated in the Foothills Front, Northwestern Alberta, and shale areas.

PSAC 2, 5 and 7 and shale will continue to be the focus of new gas developments in the province. The high NGLs content of the gas and the high productivity of the new wells are key to their appeal, plus accessibility and availability of the processing and transport infrastructure and the continued consolidation of operators in these areas. Table S5.3 shows the forecast number of new wells placed on production by PSAC area.

Table S5.3 Forecast number of Alberta new natural gas wells placed on production

Year	PSAC 1	PSAC 2	PSAC 2	PSAC 3	PSAC 4	PSAC 5	PSAC 5	PSAC 6	PSAC 7	PSAC 7	Shale	CBM[a] - HSC[b]	CBM - Mannville
	Foothills	Foothills Front		Southeastern Alberta	East Central Alberta	Central Alberta		Northeastern Alberta	Northwestern Alberta				
		vertical	horizontal			vertical	horizontal		vertical	horizontal			
2003	66	1280	67	5142	742	1300	19	601	936	13	0	840	51
2004	91	1581	46	6876	985	1664	6	535	951	6	0	1806	75
2005	63	1974	34	5626	962	2195	19	372	1129	10	1	2814	124
2006	89	2279	41	5654	820	1823	25	542	1049	19	0	3296	520
2007	66	1837	49	4549	510	1297	8	368	612	14	18	2507	262
2008	65	1495	123	3605	384	939	20	234	461	69	53	2030	251
2009	34	717	142	1990	160	437	11	129	154	64	4	1784	177
2010	15	769	278	1198	106	360	61	67	145	110	9	1082	53
2011	11	414	501	864	69	150	75	24	38	97	21	1138	50
2012	5	224	474	196	13	39	56	4	14	66	40	454	3
2013	2	97	520	181	14	40	51	1	16	56	73	230	7
2014	4	59	813	227	28	37	91	7	16	81	91	191	2
2015	4	27	740	162	11	29	54	1	5	48	116	167	1
2016	1	27	527	36	14	28	17	5	8	56	132	16	2
2017	1	47	850	42	24	44	30	24	15	85	112	17	8
2018	1	33	645	23	2	9	10	3	5	60	104	10	1
2019	1	10	554	14	2	11	6	2	1	55	73	9	1
2020	5	9	402	9	3	10	1	1	2	75	66	2	6
2021	0	7	535	19	18	15	16	0	4	131	54	12	2
2022	2	15	650	42	6	13	10	3	3	125	56	18	9
2023	1	15	650	29	1	19	1	2	7	102	61	29	4
2024	0	9	564	5	0	2	14	0	3	107	106	0	0
2025	0	10	630	10	0	5	15	0	5	110	120	10	0
2026	0	10	655	10	0	5	15	0	5	120	120	10	0
2027	0	10	670	15	0	5	15	0	5	120	125	10	0
2028	0	10	695	15	5	5	20	0	5	120	125	10	0
2029	0	10	715	15	5	5	20	0	5	120	130	10	0
2030	0	5	730	20	5	10	20	0	10	120	130	10	0
2031	0	5	745	20	5	10	25	0	10	125	130	10	0
2032	0	5	760	20	5	10	25	0	10	125	135	10	0
2033	0	5	770	20	5	10	25	0	10	125	135	10	0
2034	0	5	775	20	5	10	25	0	10	130	140	10	0

Note: Forecast values have been rounded.

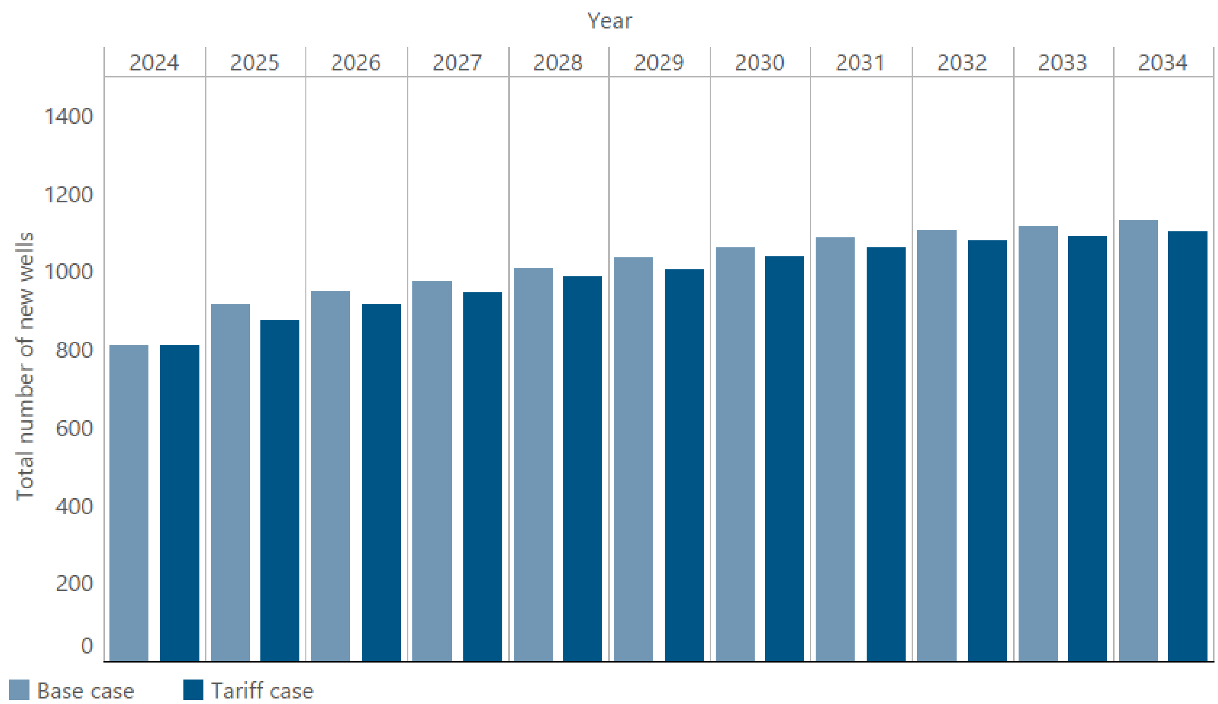
[a] Coalbed methane.

[b] Horseshoe Canyon.

5.3.4 One-Year Tariff Scenario (Tariff Case)

If tariffs are imposed, there would be some effects on wells placed on production. Increased uncertainty will discount local natural gas prices; higher material and drilling equipment costs and reduced investment will affect drilling plans. Compared with the base case, tariffs would lead to a 4.4% decline in the number of new wells placed on production in 2025, resulting in 875 wells. Although the number of new wells is expected to rise to 1100 wells in 2034, this number would still be 2.7% below the base case.

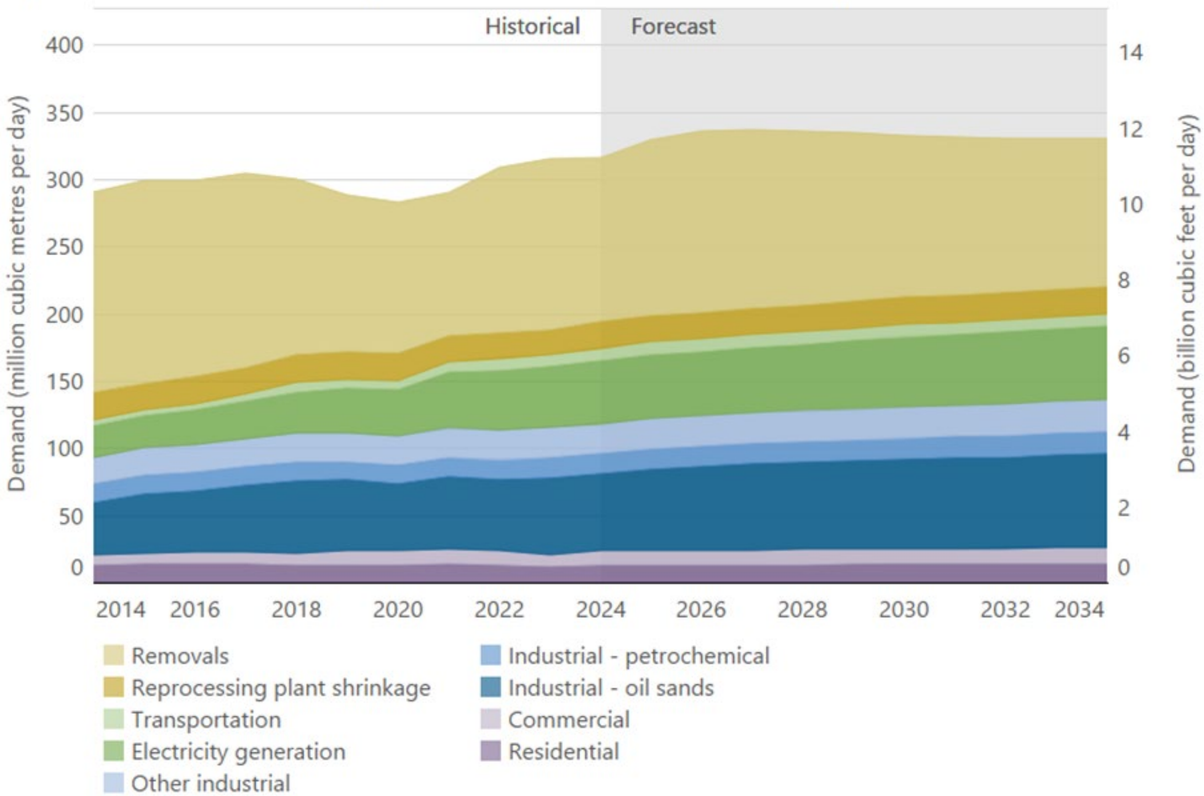
Figure S5.8 Alberta natural gas new wells placed on production (base case vs. tariff case)



5.4 Natural Gas Demand

Figure S5.9 shows historical numbers and base case forecasts of marketable gas demand in Alberta by sector and gas available for removal.

Figure S5.9 Alberta marketable gas available for removals and demand by sector



5.4.1 Demand

5.4.1.1 In 2024

Demand for natural gas in Alberta increased by 3.3% from 2023, accounting for 62% of marketable production volumes (194.3 10^6 m^3/d or 6.9 Bcf/d).

In 2024, residential natural gas demand increased by 9.2%, and commercial use by 16%. Natural gas demand for electricity generation grew by 4.7%. An increasing population and low gas prices boosted demand in these sectors. Natural gas demand for transportation grew by 3.4% and for oil sands by 0.8%.

5.4.1.2 Base Case Forecast for 2025 to 2034

Total domestic demand for natural gas in Alberta is estimated to reach 220.1 10^6 m^3/d (7.8 Bcf/d) by 2034, growing at an average annual rate of 1%. This growth rate is slower than the previous decade, where demand increased by an annual average of 3%.

The following sectors are anticipated to have an increased demand for gas over the forecast period:

- Oil sands demand is expected to grow by 22%, driven by increased demand from oil sands in situ operations.
- Electricity generation is expected to grow by 16%, driven by increases in cogeneration at oil sands facilities and rising demand for power generation.
- Other sectors combined (residential, commercial, non-oil sands industrial, and transportation) will account for the remaining growth in demand. Total demand in these sectors is expected to increase at an average annual rate of about 0.7%, driven by economic and population growth and partially offset by energy efficiency gains.
- Power generation and natural gas infrastructure to fuel new data centres may significantly increase domestic natural gas demand and will be considered in the future.

5.4.2 Removals

5.4.2.1 In 2024

Natural gas removals from Alberta (i.e., transfers to other provinces and exports to the United States) decreased by 4.4% in 2024, caused by a growth in domestic demand offsetting a decline in demand from the United States over the year. Natural gas removals are equal to the difference between Alberta's marketable gas production and Alberta's natural gas demand and may include changes to storage.

5.4.2.2 Base Case Forecast for 2025 to 2034

Removals are estimated to decrease over the forecast period to 110.0 10^6 m^3/d (3.9 Bcf/d) by 2034, declining at an average rate of 1% annually. This decrease in removals will occur as demand growth is forecast to outpace production growth. Moreover, domestic demand for natural gas is expected to increase as the province will likely increase its consumption as a transition fuel to a low-carbon economy.

Completing pipelines like the Coastal GasLink has enhanced the market accessibility of natural gas from western Canada. Alberta's natural gas is poised to compete for pipeline capacity amid increasing production from British Columbia, where producers stand to gain significantly from increased liquefied natural gas (LNG) export ventures. The anticipated rise in LNG exports and overall improvement in market accessibility are expected to benefit Alberta producers by alleviating infrastructure congestion and enhancing commodity pricing.

5.4.3 One-Year Tariff Scenario (Tariff Case)

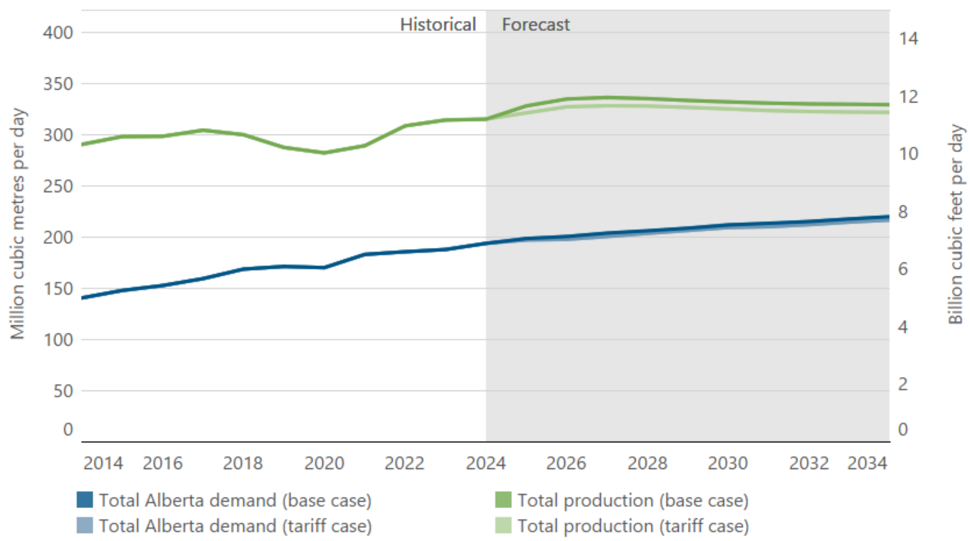
5.4.3.1 Demand

Tariffs and retaliatory tariffs can lead to overall economic slowdown in Alberta. Increased business operating costs will erode profit margins, reducing natural gas demand. Compared with the base case, the forecasted drop in demand is primarily due to a decline in natural gas consumption in the oil sands sector, which holds the largest share of domestic demand. However, rising electricity consumption and sustained natural gas demand in the residential and commercial sectors driven by population growth would keep the forecast comparable to the base case. By the end of the forecast period, 2034, natural gas demand is expected to reach 217 10^3 m^3/d (7.7 Bcf/d), a 1.4% decrease from the base case.

5.4.3.2 Removals

Under this scenario, Alberta's natural gas removals are expected to be lower due to discounted prices and worsened competitiveness. The United States, the primary export market, can increase its production and replace Alberta's natural gas. A greater drop in Alberta's production compared with its demand would lead to reduced removals in the tariff case. However, Canada's new LNG projects and changing trade patterns will significantly lessen the reliance on the U.S. market. Removals will reach 105.3 10^3 m^3/d (3.7 Bcf/d) in 2034, 4% lower than the base case.

Figure S5.10 Total marketable gas production, demand, and removals* (base case vs. tariff case)



*The difference between supply and demand are removals.

5.5 Natural Gas Storage

The natural gas industry uses commercial storage to manage seasonal gas deliveries. Excess gas produced in summer is stored and then withdrawn from storage in winter to offset peak demand. The AER does not forecast natural gas storage volumes in projections of long-term gas production.

Several pools in Alberta are used for commercial natural gas storage to balance the supply against fluctuating market demand. Storage, injections, and withdrawals in 2024 were as follows:

- Storage: Levels were 562.3 Bcf, a 10% increase from December 2023. This level is about 30% above the five-year average, equivalent to 80 days of average domestic demand.
- Injections and withdrawals: Withdrawals for commercial storage schemes fell behind injections by 1389 10^6 m^3, equivalent to about 7 days of average domestic demand. In 2024, storage experienced a net injection, as the production outweighed the demand.

Table S5.4 lists the commercial natural gas storage pools in Alberta in 2024, including capacity, injection, and withdrawal volumes.

Table S5.4 Alberta commercial natural gas storage pools as of December 31, 2024

Field	Pool	Operator	Working gas capacity* (10^6 m^3)	Working gas capacity* (Bcf)	Injection volumes (10^6 m^3)	Withdrawal volumes (10^6 m^3)
Brazeau River	Nisku E	Tidewater Midstream and Infrastructure	1 100	39		
Carrot Creek	Cardium CCC	ATCO Next Energy Ltd	986	35	458	237
Countess	Bow Island N & Upper Mannville M5M	Rockpoint Gas Storage	1 986	70	659	751
Crossfield East	Elkton A & D	TC Energy	1 916	68	683	489
Dimsdale	Paddy A	AltaGas	424	15	691	172
Edson	Viking D	TC Energy	1 409	50	676	457
Hussar	Glauconitic R	Husky Oil Operations Ltd	423	15	319	352
McLeod	Cardium D	ATCO Next Energy Ltd	282	10	194	107
Suffield	Upper Mannville I & K, and Bow Island N & BB & GGG	Rockpoint Gas Storage	2 353	84	1 120	1 043
Warwick	Glauconitic-Nisku A	Rockpoint Gas Storage	606	22	135	147
Wayne-Rosedale	Glauconitic-M5M	ATCO Next Energy Ltd	1 745	62	835	624
Total			13 230	470	5 770	4 381

Note: Working gas capacities are from the company.

*Working gas capacity refers to total gas storage capacity minus base gas.

Figure S5.11 shows the locations of all existing commercial gas storage facilities and the border delivery and export points for gas removals in Alberta.

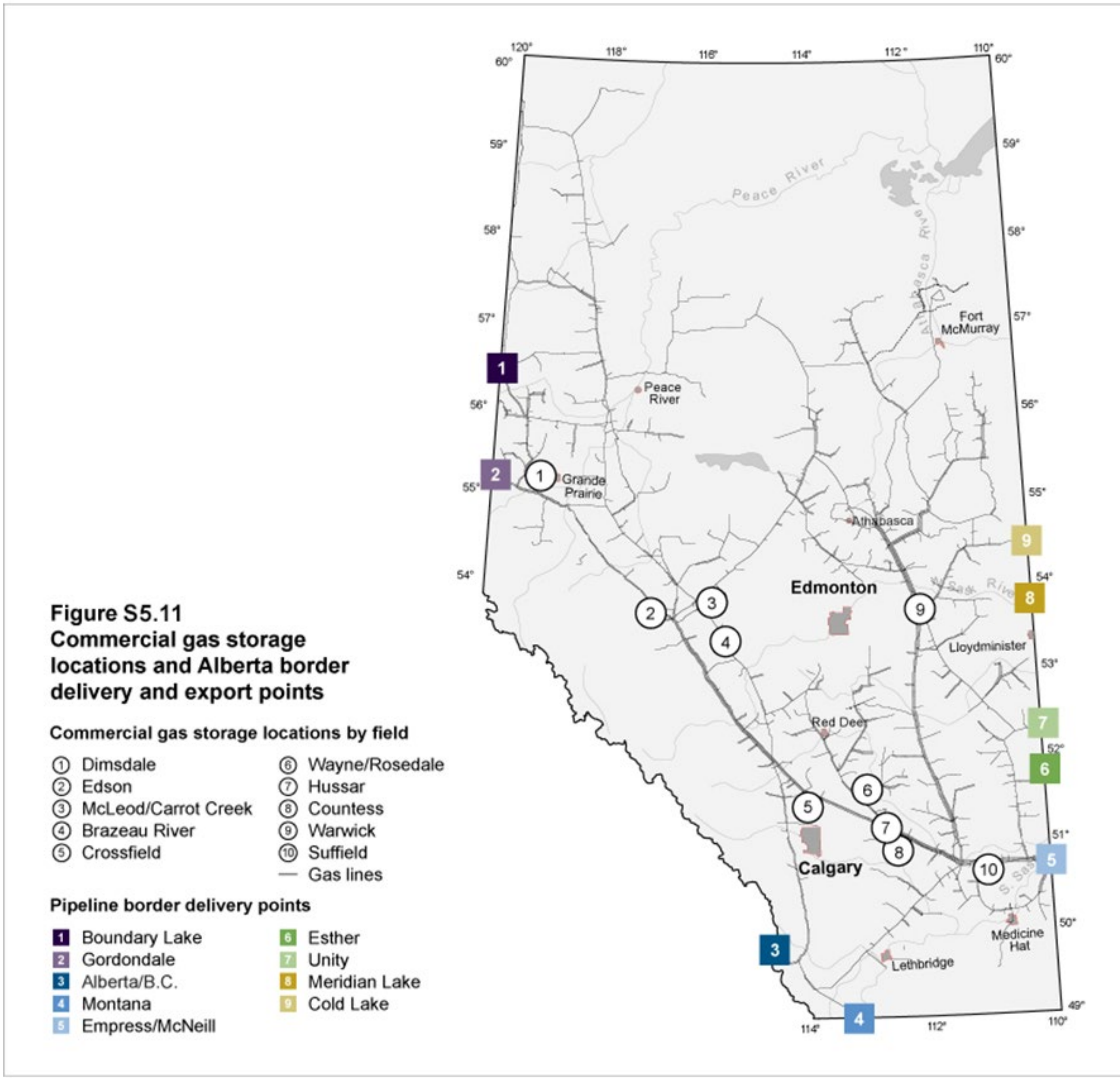


Figure S5.11
Commercial gas storage locations and Alberta border delivery and export points

5.6 Natural Gas Removal Permits

Alberta's *Gas Resources Preservation Act* proclaimed in 1949, mandates that large volumes of natural gas be reserved for domestic use to ensure that Albertans have enough natural gas supply. Consequently, companies proposing to remove gas from Alberta must first obtain a permit from the AER.

5.6.1 Short- and Long-Term Removal Permits

There are two types of removal permits in Alberta:

- Short-term gas removal permits involve
  - removals of not more than 3 billion cubic metres (10^9 m^3) of gas (0.1 trillion cubic feet [Tcf]) and
  - terms of not longer than two years.
- Long-term gas removal permits involve
  - removals of over 3.0 10^9 m^3 of gas and
  - terms of longer than two years.

Natural gas removals from Alberta are only permitted if the gas for removal is surplus to the current and future natural gas core market requirements over a 15-year period and noncore market requirements over a 5-year period.

- The core market includes Alberta residential and commercial gas consumers.
- The noncore market includes large industrial users who contract their own gas.

The AER calculates estimated gas reserves available for removal from Alberta (see Table S5.5). Based on reserves re-evaluated by an external consultant, values were estimated after accounting for Alberta's future requirements in core and noncore markets.

The AER has calculated that as of December 31, 2024, an additional 3094 10^9 m^3 (10^9 Tcf) of gas is available for removal permits.

Table S5.5 Estimate of gas reserves available for inclusion in removal permits as of December 31, 2024

	10^9 m^3
Remaining established reserves (as of year-end)[a]	3663
Less Alberta requirements	
Core market requirements[b]	129
Contracted for noncore markets[b]	257
Permit-related fuel and shrinkage[c]	17
Less Permit requirements[d]	166
Available	3094

[a] The remaining established reserves were updated in 2025 with a new methodology and is only for the Montney, Duvernay, Spirit River, and Clearwater Formations.

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

[c] The shrinkage, fuel, and loss associated with the transportation of gas removed from Alberta, and the removal of natural gas liquids from reprocessing plants within Alberta.

[d] Permit requirements are the total volumes authorized for removal from the province. Of these volumes, 100% are permitted under short-term and 0% under long-term permits.

Note: Gas imported to Alberta is not considered in the calculation. If included, the amount of gas available for removal permit would be higher than estimated in this table.

5.7 Natural Gas Supply Costs

The supply cost of a resource project is the minimum constant dollar price needed to recover all capital expenditures, operating costs, royalties, taxes, and earn a specified return on investment. Supply costs indicate whether a project is economically viable and are interpreted as the value required per unit of production.

Understanding the underlying geology allows the most effective and cost-efficient completion technology to be used. The supply cost for different geological plays and PSAC areas varies significantly because of differing

- production rates,
- NGLs content in the gas,
- well types,
- drilling and operating costs, and
- royalties.

Wells with a longer total measured depth, typically horizontal wells, tend to have higher initial productivity and capital costs. However, the high initial productivity of these wells will generally offset high capital costs, leading to lower supply costs.

Typically, wells that target liquids-rich gas have lower supply costs. As a by-product, liquids add to revenues, offsetting the costs of a well. Wells targeting liquids-rich gas are mainly in

- Foothills Front (PSAC area 2),
- Central Alberta (PSAC area 5), and
- Northwestern Alberta (PSAC area 7).

5.7.1 Supply Costs by PSAC Area

Table S5.6 shows the estimated costs for gas, shale, and CBM natural gas wells by PSAC area based on 2024 capital and operating costs and production profiles. Operators often drill multiple wells from a well pad, referred to as a multiwell pad. These wells benefit from economies of scale and usually incur lower capital costs, resulting in a lower cost per unit of output. Supply costs are lowest for horizontal wells in the Foothills Front and Northwestern Alberta areas (PSAC areas 2 and 7).

Recompletions were not considered in the analysis. They are substantially cheaper than new drills but have weaker initial productivity rates.

Most areas of Alberta experienced increased natural gas supply costs in 2024, mainly due to increased capital and operating costs. According to the latest PSAC well cost study, drilling and completion costs for gas wells in Alberta were, on average, 1.5% higher than in 2023.

North American upstream operating costs were estimated to be 1.5% higher in 2024 compared with 2023. Production of NGLs helped with the economics of natural gas wells and supply costs.

5.7.2 One-Year Tariff Scenario (Tariff Case)

Natural gas supply costs are expected to be slightly higher than the base case. Increased production costs, particularly drilling and completion, will affect supply costs.

Due to the tariffs imposed by the United States on Canadian oil and gas exports and Canadian retaliatory tariffs, supply cost ranges in Table S5.6 have been included, which include an upper and lower bound. The lower bound represents the base case cost estimates, and the upper bound is the tariff case-adjusted cost estimates. Tariffs are assumed to last one year, increasing the costs of key oil and gas drilling and production inputs.

Table S5.6 Alberta natural gas supply costs by PSAC area, 2024

Area	Formation	Type of well	Type of gas	Total measured depth (m)	Initial productivity (10^3 m^3/d)	Total capital cost (Cdn$000)	Fixed operating cost (Cdn$000/year)	Variable operating cost (Cdn$/$10^3$ m^3)	Natural gas supply cost - single well (Cdn$/GJ)	Natural gas supply cost - 4 well pad (Cdn$/GJ)
PSAC 2	Shunda	Directional	Sour	3 565	13.8	3 343	50.69	70.01	5.35-5.53	n/a
PSAC 2	Cardium	Horizontal	Sweet	5 000	30.8	6 005	41.75	65.57	3.07-3.17	2.6-2.68
PSAC 2	Montney	Horizontal	Sweet	5 000	58.2	13 315	41.75	65.57	5.3-5.48	4.2-4.34
PSAC 5	Manville	Vertical	Sweet	1 150	3.2	1 352	25.89	81.59	8.66-8.95	n/a
PSAC 5	Duvernay	Horizontal	Sweet	6 000	39.0	12 185	41.75	81.59	7.57-7.82	6.34-6.55
PSAC 6	Grand Rapids	Vertical	Sweet	600	1.4	1 371	32.50	60.19	13.36-13.81	n/a
PSAC 7	Montney	Horizontal	Sweet	4 500	61.8	8 817	58.65	59.43	1.81-1.87	1.19-1.23
Shale	Duvernay	Horizontal	Sweet	6 000	40.9	10 523	41.75	64.97	7.26-7.51	5.78-5.97
CBM - MNN[b]	Manville	Horizontal	Coal gas	2 400	1.2	2 884	25.89	25.59	21.04-21.74	n/a

Note: Cost data from petroCUBE, Sproule, and Enserva Well Cost Study Winter 2024 have been used to estimate the supply costs.
[a] Not applicable (n/a).
[b] Coalbed methane Manville Corbett.

5.8 Natural Gas Methodology

5.8.1 Marketable Natural Gas

Marketable gas is natural gas that remains after raw gas is processed (to remove nonhydrocarbons and heavier NGLs) and meets the specifications for use as a fuel. Marketable 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” gas) or the volume at standard conditions of 37.4 megajoules per cubic metre (MJ/m^3). The average heat content of produced natural gas leaving a field plant is estimated to be 39.7 MJ/m^3, compared with coalbed methane (CBM) at about 37.0 MJ/m^3.

Marketable natural gas production volumes for gas are calculated based on production data from the section on supply and disposition of marketable gas in *ST3: Alberta Energy Resource Industries Monthly Statistics*.

Table S5.7 shows the marketable Alberta natural gas volumes for 2023 and 2024.

Table S5.7 Alberta marketable natural gas volumes

Marketable gas production (10^9 m^3)	2023	2024
Total raw gas production	130.5	131.1
Minus production from coalbed methane and hybrid connections (CBM)	4.4	4.0
Total raw gas production (including shale)	126.2	127.0
Minus total injection	2.1	2.5
Minus flared—raw	1.2	1.3
Minus fuel—raw	8.8	8.8
Minus vented—raw	0.3	0.3
Minus processing shrinkage–raw	9.4	9.4
Marketable gas production at as is conditons (including shale)	104.5	104.8
Marketable gas production at 37.4 MJ/m^3 (including shale)	110.6	111.2
Minus marketable shale	4.0	5.1
Conventional marketable gas production at 37.4 MJ/m^3 (excluding shale and CBM)	106.6	106.1
Plus marketable shale	4.0	5.1
Plus marketable CBM	4.4	4.0
Total marketable gas production at 37.4 MJ/m^3 (including shale and CBM)	115.0	115.2
Average daily rate of marketable gas at 37.4 MJ/m^3 (10^6 m^3/d)		
Conventional marketable gas production (excluding shale and CBM)	292.1	290.6
Total marketable gas production (including shale and CBM)	315.0	315.7

Note: Billion cubic metres (10^9 m^3) and million cubic metres per day (10^6 m^3/d).

5.8.2 Coalbed Methane and Shale Gas

CBM and shale wells are not classified within a specific PSAC area. For this reason, they are presented as a separate category in our estimates. Shale gas and CBM-producing wells are re-evaluated based on new information because historical annual values can change.

5.8.3 Forecasting Natural Gas Production

The AER includes three well-type classifications for natural gas production and gas produced from oil wells:

- CBM: methane found in coal seams as adsorbed or free gas.
- Shale gas: natural gas locked in fine-grained, organic-rich rock.
- Conventional and tight gas: tight gas refers to natural gas found in low-permeability rocks such as sandstone, siltstone, and carbonates.
- Gas from oil wells.

Although tight-gas volumes are included in the AER's natural gas reserves and production reporting, it is difficult (sometimes impossible) to separate the tight portion of the reserves or production in a conventional reservoir.

Our forecasts for marketable natural gas production consider

- expected production from existing gas wells,
- expected production from new gas wells placed on production,
- gas production from oil wells, and
- prices, royalties, taxes, capital costs, carbon price, and other costs.

Our forecasts also account for estimates of the remaining established and yet-to-be-established reserves of natural gas in Alberta. We use the Modernized Royalty Framework to estimate royalties.

A net present value is calculated for representative wells for all years of the forecast and forms the basis of the forecast. Limiting factors, such as current and future capital market conditions and remaining reserves, are also considered.

Gas production is forecast separately for conventional and tight, shale, and CBM wells. All projections are combined for a total marketable gas production forecast for Alberta. Continual reclassification of CBM and shale wells placed on production results in revisions to historical data and changes to annual forecasts.

5.8.4 Initial Productivity Rates

Table S5.8 shows the forecast of initial average productivity for new natural gas (by PSAC area), shale, and CBM wells. These numbers form the basis of the average well productivity over time and are paired with the number of producing wells to forecast production. Initial productivity rates are expected to decline in most areas.

Table S5.8 Forecast initial productivities for new Alberta natural gas wells (10^3 m^3/d)

Area	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
PSAC 1	5.2	5.2	5.2	5.2	5.1	5.1	5.1	5.1	5.1	5.1	5.1
PSAC 2 vertical	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.7	13.7	13.7	13.7
PSAC 2 horizontal	54.8	54.8	54.7	54.7	54.7	54.7	54.7	54.7	54.7	54.6	54.6
PSAC 3	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.7	1.7	1.7
PSAC 4	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
PSAC 5 vertical	2.7	2.7	2.7	2.7	2.7	2.6	2.6	2.6	2.6	2.6	2.6
PSAC 5 horizontal	39.0	38.9	38.8	38.8	38.7	38.6	38.5	38.4	38.4	38.3	38.2
PSAC 6	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
PSAC 7 vertical	19.5	19.4	19.4	19.3	19.3	19.3	19.2	19.2	19.1	19.1	19.1
PSAC 7 horizontal	53.0	52.9	52.8	52.7	52.6	52.4	52.3	52.2	52.1	52.0	51.9
Shale	37.5	37.4	37.3	37.3	37.2	37.1	37.0	37.0	36.9	36.8	36.7
HSC[a] coalbed methane	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Mannville coalbed methane	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.1	1.1

[a] Horseshoe Canyon.

5.8.5 Main Factors in Predicting Volumes

We rely on data from the associated decline rates (Table S5.9) to project natural gas volumes. Decline rates for gas production from gas wells vary depending on a well's age, type, and geological location.

Table S5.9 Forecast production decline rates for new Alberta natural gas wells (%)

PSAC area	Year 1	Year 2	Year 3	Year 4-10
PSAC 1 Foothills	-31	-16	-14	-10
PSAC 2 Foothills Front - vertical	-27	-18	-17	-9
PSAC 2 Foothills Front - horizontal	-43	-29	-23	-13
PSAC 3 Southeastern Alberta	-32	-22	-15	-10
PSAC 4 East Central Alberta	-29	-25	-21	-9
PSAC 5 Central Alberta - vertical	-28	-21	-15	-9
PSAC 5 Central Alberta - horizontal	-44	-28	-23	-10
PSAC 6 Northeastern Alberta	-28	-20	-20	-10
PSAC 7 Northwestern Alberta - vertical	-27	-25	-24	-10
PSAC 7 Northwestern Alberta - horizontal	-35	-26	-18	-11
Shale	-34	-25	-19	-14
HSC[a] coalbed methane	-15	-12	-13	-7
Mannville coalbed methane	-15	-10	-8	-5

[a] Horseshoe Canyon.

5.8.6 Natural Gas Production Forecast Accuracy

The natural gas production has shown reasonably good accuracy. The forecast deviation from the 2024 actual natural gas production ranged from 6% to 10%. The 2024 natural gas production forecasts from the 2019 and 2021 forecast had the highest deviation of 10% from the actual 2024 natural gas production, due to a combination of uncertainty surrounding the global economic pandemic, geopolitical, and industry-specific factors.

5.8.7 Demand Forecast

The Alberta natural gas demand forecast is based on a sector-by-sector analysis of past, present, and future drivers of natural gas use. For example, demand forecasts for sectors such as oil sands and electricity generation depend on other forecasts, such as crude bitumen production, total electricity demand, and growth in renewable electricity generation.

Natural gas removals are equal to the difference between Alberta's marketable gas production and Alberta's natural gas demand and may include changes to storage. Removals are assumed to satisfy natural gas permitting conditions.

5.8.8 Supply Costs

A supply cost, or "breakeven" price, is the minimum constant dollar price needed for an operator to recover all capital expenditures, operating costs, royalties, and taxes. It is expressed as a dollar value required per unit of production.

The following data were used to derive a supply cost estimate for the average horizontal or vertical/directional well in each PSAC area:

- initial productivity
- production decline rates
- vertical depth
- total measured depth
- gas composition
- shrinkage
- capital costs (drilling, casing, completion, and land acquisition)
- operating costs (processing and transportation)
- royalties
- taxes
- prices of by-products such as NGLs and sulphur
- a 10% nominal rate of return

The supply cost estimates are not risked (i.e., assume a 100% success rate in drilling) and are estimated at plant-gate prices and reported in Canadian dollars. Representative wells in the Foothills, Foothills Front, Central, and Northwestern areas of Alberta (PSAC areas 1, 2, 5, and 7) and the representative wells for shale wells are assumed to produce NGLs as by-product.

5.8.9 Data

We used natural gas production volumes submitted to Petrinex. Petrinex is a secure, centralized information network used to exchange petroleum-related information. All 2024 data are as reported by the industry up until the end of December and do not include any subsequent amendments.

6 Natural Gas Liquids

Companies recover natural gas liquids (NGLs) mainly from processing natural gas. Natural gas can be produced directly from a hydrocarbon reservoir as raw gas or mixed with crude oil or bitumen as associated gas.

6.1 Processing Facilities

6.1.1 Field Gas-Processing Facilities

Field gas-processing facilities (field plants) process natural gas to meet pipeline quality specifications, often involving removing NGLs. These removed NGL volumes include ethane, propane, butane, and pentanes plus. Companies sell these volumes separately to obtain full value for each NGL component.

Field plants send the recovered NGL mix to centralized large-scale fractionation plants that separate the components (i.e., ethane, propane, butane, and pentanes plus).

6.1.2 Straddle Plants

Straddle plants are gas reprocessing plants that recover NGL components or NGL mix from marketable gas. They are usually situated on main gas transmission pipelines at border delivery points.

6.2 Tariff Scenarios

Because of significant uncertainty, particularly regarding U.S. tariff policies, this year's report examines two scenarios: a short-term tariff uncertainty scenario (base case) and a one-year tariff scenario (tariff case). The primary difference between these scenarios lies in their tariff assumptions.

- **Base case**: This scenario assumes business as usual and no tariffs. However, the U.S. tariff threats on energy products (oil and gas) persist throughout the first half of 2025 but are ultimately averted through diplomatic negotiations by midyear. Consequently, energy supply and demand are minimally affected.
- **Tariff case**: This scenario assumes a 10% U.S. tariff on energy products (oil and gas) and 25% tariffs on other Canadian goods imposed in the first half of 2025 despite diplomatic efforts. This scenario includes subsequent U.S. and Canadian retaliatory tariffs, other nontariff measures, and additional U.S. tariffs on other trading partners. All tariffs and nontariff measures between Canada and the United States persist until the end of the first quarter of 2026 before mostly being phased out as the review or renegotiation of the

Canada-United States-Mexico Agreement. It is expected tariffs will have some long-term effects and structural changes to the global economy (changes in trade and investment flows).

These tariff assumptions affect prices, costs, commodity profitability, investment, supply and demand, project risk factors, and commercial start dates (where applicable) for most chapters of the report, including comparisons of the outcomes of these scenarios.

6.3 Production and Demand

6.3.1 Ethane

6.3.1.1 In 2024

Production: Ethane production in Alberta grew 3.4% in 2024 compared with 2023, averaging 37.5 thousand cubic metres per day (10^3 m^3/d) or 237.4 thousand barrels per day (10^3 bbl/d). Production growth for 2024 was supported by less ethane rejection (i.e., leaving ethane in the natural gas stream and not extracting it for use).

Demand: In 2024, Alberta's demand for ethane grew to 42.8 10^3 m^3/d (270.7 10^3 bbl/d). The demand growth for ethane in 2024 was consistent with increased use in the petrochemical sector.

Alberta imports ethane via the Vantage pipeline to meet the petrochemical sector's demand. Vantage pipeline imports increased to 5.3 10^3 m^3/d (33.4 10^3 bbl/d).

6.3.1.2 Base Case Forecast for 2025 to 2034

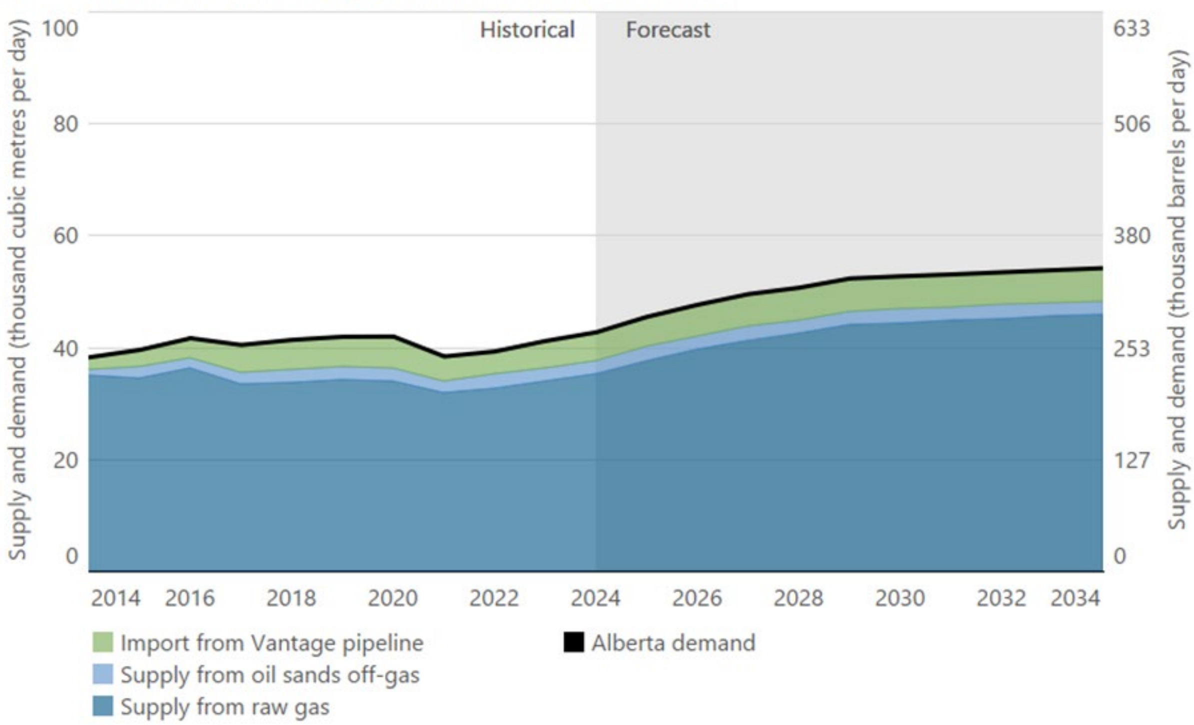
Production: Ethane production is forecast to rise significantly, reaching 48.3 10^3 m^3/d (305.7 10^3 bbl/d) by 2034. Raw natural gas production is projected to grow slightly over the next ten years. However, as ethane prices are expected to rise, improved recovery economics will grow the ethane supply as more ethane is extracted from natural gas (i.e., lower ethane rejection).

A part of Alberta's ethane production has been rejected historically due to a lack of capacity in processing ethane and a share of demand being satisfied by contracted imports.

Demand: Ethane demand continues to grow and will be 45.5 10^3 m^3/d (288.2 10^3 bbl/d) in 2025, reaching 54.2 10^3 m^3/d (343.3 10^3 bbl/d) by 2034. Growth in demand over the forecast period is driven primarily by the Path2Zero expansion project, which will triple the existing ethylene and polyethylene capacity of Dow Chemical's plant in Fort Saskatchewan. Although, Dow has announced a delay to its Path2Zero expansion project, the company remains committed to its long-term execution.

Figure S6.1 shows Alberta's ethane supply from natural gas and demand in the base case.

Figure S6.1 Alberta ethane supply from natural gas and demand



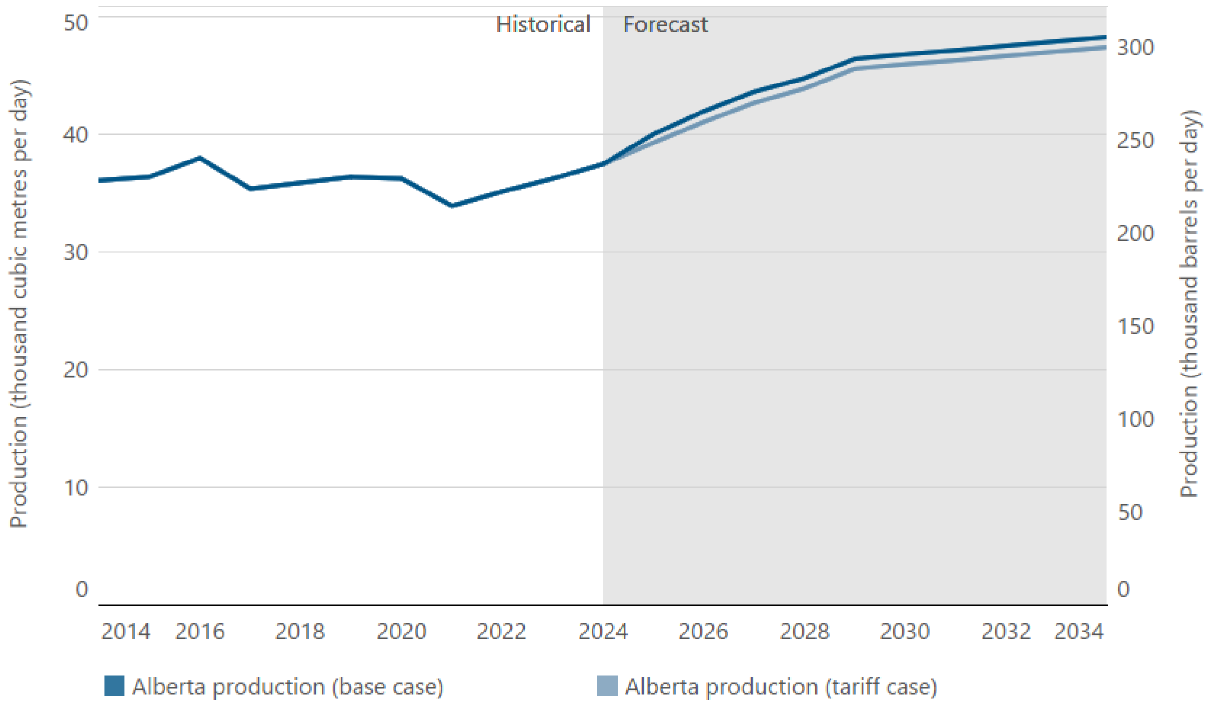
6.3.1.3 One-Year Tariff Scenario (Tariff Case)

Compared with the base case, ethane production in Alberta for the tariff case is expected to experience a marginal decline driven by lower natural gas production due to tariff-related uncertainties. The broad tariffs on non-oil-and-gas industries will negatively affect Alberta's petrochemical industry and domestic ethane demand. Although ethane production and demand are lower than the base case, the relative declines are expected to be small due to the assumption that tariffs will only be in place for one year.

Production is forecast to be lower by 1.8%, decreasing to 39.3 10^3 m^3/d (248.9 10^3 bbl/d) in 2025 compared with the base case. As market conditions stabilize following the assumed one-year tariffs, production is expected to recover. By 2026, tariff-related impacts would be minimal, and ethane production is projected to grow steadily over the forecast period, reaching 47.4 10^3 m^3/d (300.2 10^3 bbl/d) by 2034.

Figure S6.2 shows Alberta's ethane production difference between the base case and the tariff case.

Figure S6.2 Alberta total ethane production from natural gas (base case vs. tariff case)



6.3.2 Propane

6.3.2.1 In 2024

Production: Propane production in Alberta reached 40.5 10^3 m^3/d (255.2 10^3 bbl/d) in 2024, up 8.2% from 2023, driven by increased yields from field gas-processing and fractionation facilities.

Demand: In 2024, Alberta's demand for propane grew to 12.9 10^3 m^3/d (81.5 10^3 bbl/d), up 8.6% from 2023. The Methanex Medicine Hat facility accounted for most of the increased demand for propane.

6.3.2.2 Base Case Forecast for 2025 to 2034

Production: Propane production is projected to grow over the forecast period, reflecting expected growth in natural gas production and continued targeting of liquids-rich gas by producers. Propane production is expected to increase from 43.4 10^3 m^3/d (273.4 10^3 bbl/d) in 2025 to 47.5 10^3 m^3/d (299.3 10^3 bbl/d) by 2034. This gradual growth aligns with the production forecast for natural gas.

Demand: Propane demand in 2025 is projected to grow by 6.5% compared with 2024, increasing to 13.8 10^3 m^3/d (86.8 10^3 bbl/d), mainly due to rising demand from the Methanex Medicine Hat facility.

Propane demand grows steadily throughout the forecast period, reaching 17.7 10^3 m^3/d (111.3 10^3 bbl/d) by 2034. This increase is driven primarily by Pembina Pipeline Corp.'s feedstock requirements as part of the Redwater fractionation expansion.

Propane is exported by rail to the United States to meet agricultural and seasonal demand.

6.3.2.3 One-Year Tariff Scenario (Tariff Case)

Propane production in Alberta is expected to experience modest impacts under the tariff case. Reduced upstream activity and lower natural gas production, driven by tariff-related uncertainty, may constrain output.

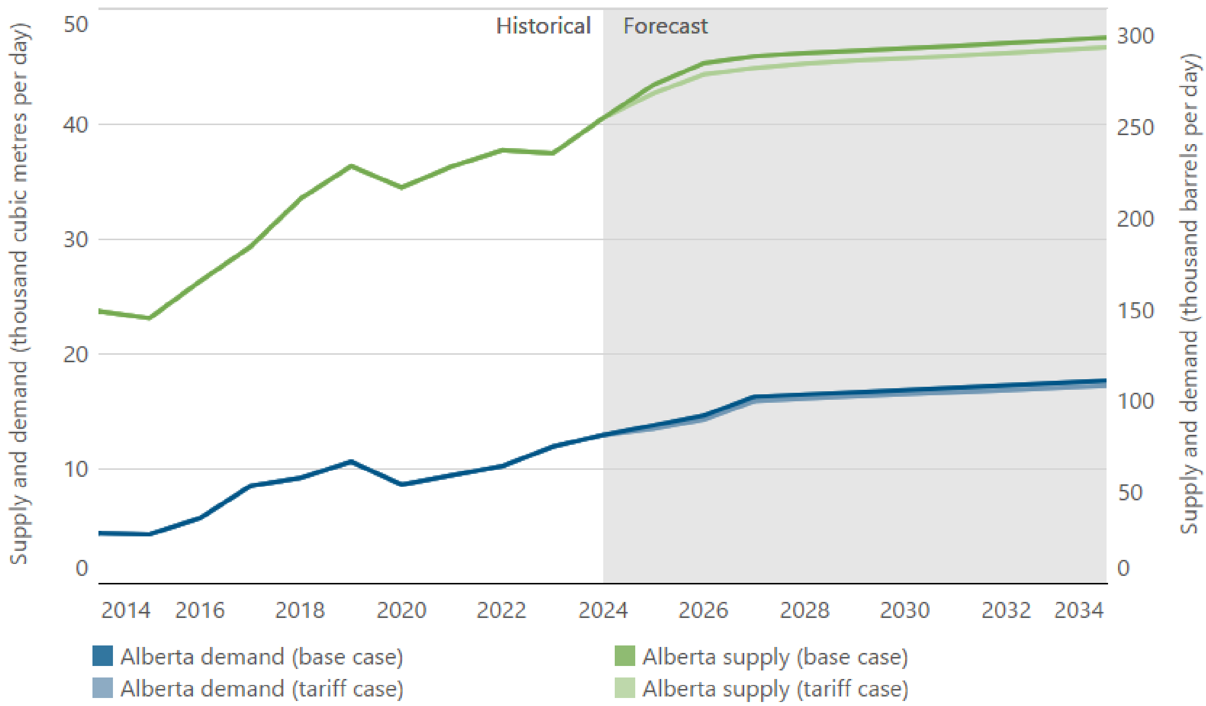
Under the tariff case, propane production is expected to be lower by 1.7%, decreasing to 42.7 10^3 m^3/d (268.8 10^3 bbl/d) in 2025, compared with the base case. However, as market conditions improve and natural gas production recovers, propane output is projected to rise by 1.4%, on average, over the forecast period, reaching 46.7 10^3 m^3/d (294.0 10^3 bbl/d) by 2034.

While we expect local propane demand to remain relatively stable, Alberta consistently produces more propane than it consumes domestically. The excess volume (i.e., removals) is primarily exported to the United States. Under the tariff case, these removals are expected to shrink, reflecting reduced cross-border trade activity.

The impact of tariffs on Alberta's demand is projected to be minimal. Domestic propane demand is expected to be 2.2% lower than the base case in 2025 due to slightly reduced consumption across user industries. Demand is projected to grow to 17.2 10^3 m^3/d (108.6 10^3 bbl/d) by 2034.

Figure S6.3 shows Alberta's propane supply and demand differences between the base case and the tariff case.

Figure S6.3 Alberta propane supply from natural gas and demand (base case vs. tariff case)



6.3.3 Butane

6.3.3.1 In 2024

Production: Butane production in Alberta grew in 2024, averaging 24.3 10^3 m^3/d (152.8 10^3 bbl/d). Excess supply is assumed to be stored or exported out of the province, including as a mixed product, such as liquefied petroleum gas.

Demand: Butane demand fell marginally by 0.4% in 2024 to 19.4 10^3 m^3/d (122.1 10^3 bbl/d), driven by a slight decline in its use as feedstock in the petrochemical industry. However, demand remained supported by blending requirements for nonupgraded bitumen.

6.3.3.2 Base Case Forecast for 2025 to 2034

Production: Butane production is projected to grow steadily throughout the forecast period at an annual average of 2.2%, reaching 30.2 10^3 m^3/d (190.0 10^3 bbl/d) by 2034 as producers continue to target economically attractive liquids-rich gas plays like the Duvernay and Montney Formations.

Demand: Butane demand is also projected to maintain steady growth, reaching 22.7 10^3 m^3/d (143.0 10^3 bbl/d) by 2034, driven primarily by consistent demand for blending with nonupgraded bitumen.

6.3.3.3 One-Year Tariff Scenario (Tariff Case)

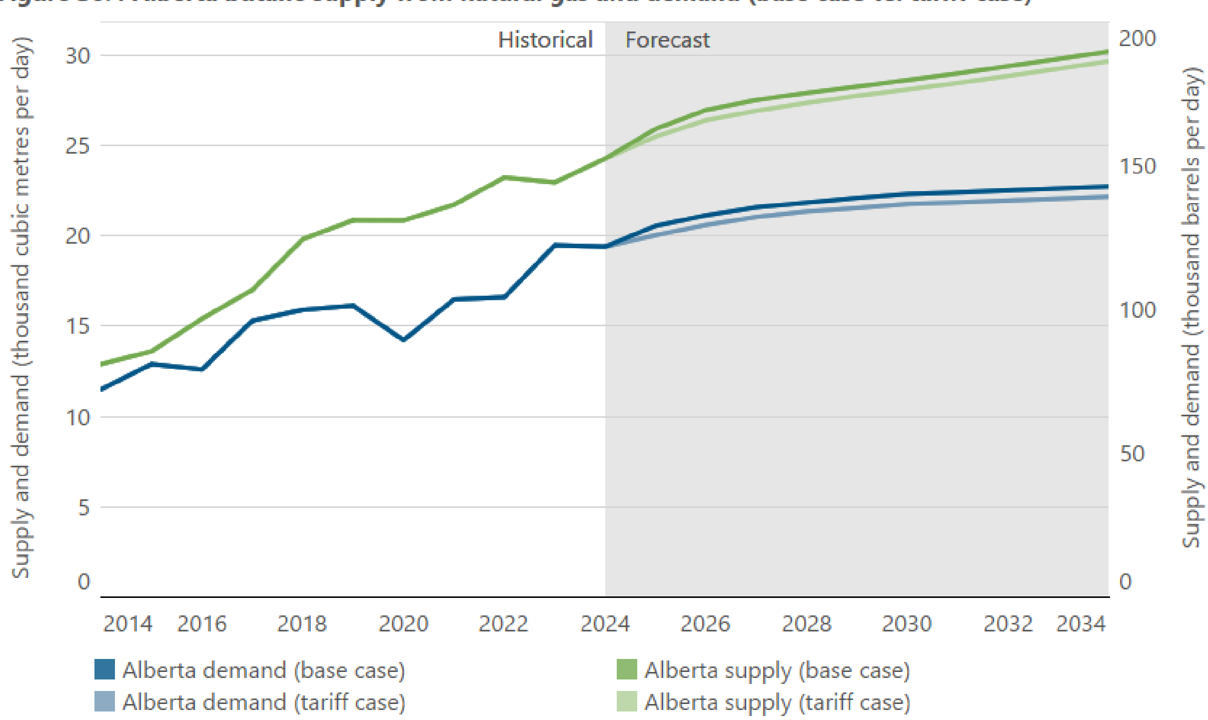
Alberta's butane production is expected to face modest headwinds under the tariff case, driven by reduced natural gas output and associated feedstock availability. While the province generally produces more butane than is needed for local consumption, the balance between production and demand is expected to remain relatively stable.

Even in the tariff case, butane is still in demand, and the broader impact of tariffs on Alberta's butane consumption is expected to be limited. Butane continues to be used for blending nonupgraded bitumen and in other industrial processes, supporting a consistent level of domestic demand.

In 2025, butane production is forecast to be lower by 1.7%, decreasing to 25.5 10^3 m^3/d (160.4 10^3 bbl/d) compared with the base case, reflecting early impacts from market uncertainty. However, these effects are expected to diminish after one year, assuming the resolution of tariffs through diplomatic means. By 2034, butane production is projected to grow to 29.6 10^3 m^3/d (186.6 10^3 bbl/d).

Demand is forecast to be 2.5% lower than the base case in 2025, largely due to reduced blending requirements for nonupgraded bitumen. As market conditions improve, demand is expected to recover, reaching 22.2 10^3 m^3/d (139.5 10^3 bbl/d) by 2034. Figure S6.4 shows Alberta's butane supply and demand differences between the base case and the tariff case.

Figure S6.4 Alberta butane supply from natural gas and demand (base case vs. tariff case)



6.3.4 Pentanes Plus

6.3.4.1 In 2024

Production: Pentanes plus production in Alberta grew by 6.8% in 2024 compared with 2023, averaging 63.0 10^3 m^3/d (396.2 10^3 bbl/d), driven by higher recovery from field plants.

Demand: In 2024, Alberta's demand for pentanes plus grew to 119.4 10^3 m^3/d (751.1 10^3 bbl/d), up 5.1% from 2023, as higher bitumen production drove the increase in diluent demand.

6.3.4.2 Base Case Forecast for 2025 to 2034

Production: Pentanes plus production is projected to grow over the forecast period, reaching a high of 74.9 10^3 m^3/d (471.5 10^3 bbl/d) by 2034 as producers continue targeting the liquids-rich Montney and Duvernay Formations.

Demand: Demand for pentanes plus is projected to grow, reaching 148.4 10^3 m^3/d (933.7 10^3 bbl/d) by 2034. This forecast correlates with bitumen production projections over the forecast period.

Imports of pentanes plus into Alberta are also expected to increase over the next ten years to meet the forecast shortfall between supply and demand for diluent. Alberta currently imports pentanes plus by rail and pipeline (e.g., Pembina Cochin Pipeline and Enbridge's Southern Lights pipeline systems).

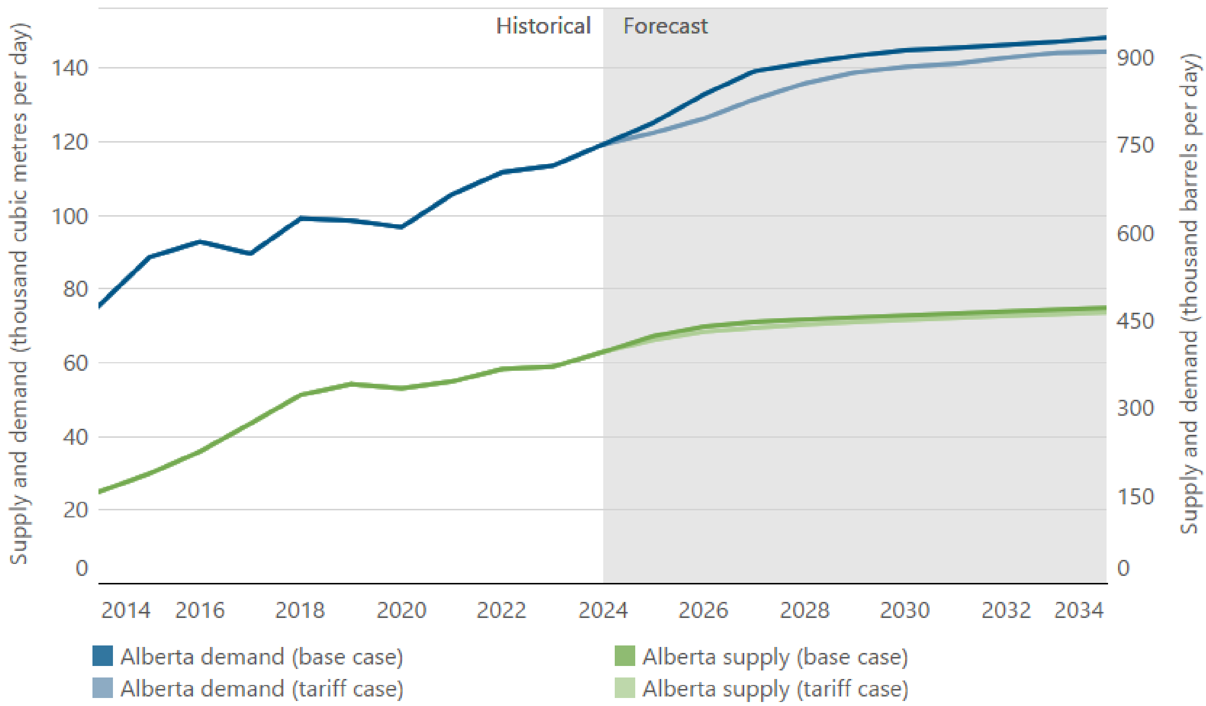
6.3.4.3 One-Year Tariff Scenario (Tariff Case)

Pentanes plus production in Alberta is expected to marginally decline under the tariff case, primarily due to reduced natural gas output. Compared with the base case, production is forecast to be 1.5% lower in 2025, reaching 66.2 10^3 m^3/d (416.8 10^3 bbl/d). As market conditions stabilize and upstream activity strengthens, production is projected to increase gradually, reaching 73.7 10^3 m^3/d (464.0 10^3 bbl/d) by 2034.

Alberta relies on imports to meet domestic pentanes plus demand. Under the tariff case, higher import costs are expected to weigh on near- and mid-term consumption. Demand is forecast to be 2.2% lower in 2025 than the base case, reflecting reduced demand for diluent used in bitumen production. Following the assumed one-year duration of tariffs under this scenario, demand is expected to recover, rising steadily to reach 144.6 10^3 m^3/d (909.8 10^3 bbl/d) by 2034.

Figure S6.5 shows Alberta's pentanes plus supply and demand differences between the base case and the tariff case.

Figure S6.5 Alberta pentanes plus supply from natural gas and demand (base case vs. tariff case)



6.4 Natural Gas Liquids Methodology

6.4.1 Supply Forecast

The production forecast model for ethane, propane, butane, and pentanes plus is based on all types of raw gas production in Alberta, including gas produced from oil wells (associated gas) and gas imports from British Columbia. The model accounts for the NGL content traced back to the reservoir and how much liquid can be recovered (the liquid recovery factor) from the representative fields, fractionation plants, and straddle plants.

6.4.2 Ethane Demand Forecast

The ethane demand forecast considers the ethylene production capacities in Alberta's petrochemical sector. Currently, no specification grade (spec grade) ethane is removed from the province; however, volumes of unrecovered ethane are removed from the province as part of the natural gas stream. This is also known as ethane rejection. Alberta imports ethane to meet the shortfall between supply and demand.

6.4.3 Propane Demand Forecast

The propane demand forecast incorporates demand from the residential, commercial, industrial, agricultural, and transportation sectors. As Alberta’s production exceeds demand, surplus propane is assumed to have been stored or removed from the province, including as a mixed product, such as liquefied petroleum gas (LPG).

6.4.4 Butane Demand Forecast

The butane demand forecast incorporates butane used as feedstock in the petrochemical sector to create value-added products (e.g., octane additives for gasoline and methanol). Butane is also used as a diluent for blending with heavy oil and bitumen to lower their viscosity for rail and pipeline transportation. As Alberta’s production exceeds demand, surplus butane is assumed to be stored or removed from the province, including as a mixed product, such as LPG.

6.4.5 Pentanes Plus Demand Forecast

The pentanes plus demand forecast incorporates demand for pentanes plus as a diluent to lower the viscosity of heavy oil or bitumen for rail and pipeline transportation.

Alberta's demand for pentanes plus exceeds its supply. Consequently, any pentanes plus removed from the province as diluted bitumen is partially recycled and mixed with U.S. pentanes plus production for import to Alberta via pipelines.

Demand for diluents, such as butanes and pentanes plus, is based on the densities of bitumen and heavy oil and how much diluent is needed to reduce their viscosity for transportation by pipeline or rail to meet density specification.

6.4.6 Data

All 2024 data are as reported by industry until the end of December and do not capture any subsequent amendments. We used NGL volumes submitted to Petrinex by field plant, fractionation plant, and straddle plant operators.

7 Coal

7.1 Highlights of 2024

Total production of marketable coal decreased by 32% in 2024.

Of all marketable coal produced in 2024,

- 0.3% was subbituminous,
- 92.6% was thermal bituminous, and
- 7.1% was metallurgical bituminous.

7.2 About Coal

Coal is a combustible sedimentary rock with more than 50% carbon-rich organic matter. It also contains oxygen, hydrogen, sulphur, nitrogen, ash, and other constituents. Coal is found in many formations across central and southern Alberta, 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 considered raw coal. Some coal, particularly coal from the mountain and foothills regions of Alberta, needs to be processed to clean coal before it is sent to market. Collectively, clean coal (usually sold internationally) and raw coal (usually sold within Alberta) are known as marketable coal.

7.3 Marketable Coal in Alberta

Companies in Alberta produce three types of marketable coal:

- Subbituminous coal: This type is found across the plains region of Alberta and is suitable for domestic power generation and heating. Subbituminous coal was mainly used to generate electricity and has been adversely affected by the retirement and conversions of coal-fired power plants within Alberta.
- Metallurgical bituminous coal: Commonly known as coking coal or low-to medium-volatile-ranked coal. This coal is from the mountain region and is exported after processing and used for industrial applications, such as steel production.
- Thermal bituminous coal: Known as steaming or high-volatile-ranked coal. Thermal bituminous coal is from the foothills region. It is primarily exported after processing and is used to fuel electricity generators in distant markets. The higher energy content and corresponding monetary value of Alberta's thermal bituminous coal make it economical for long-distance transport.

Typically, subbituminous coal is burned without needing upgrading, whereas metallurgical and thermal coals are sent in raw form to a preparation plant. To get a higher energy content and economic value for clean coal, a preparation plant washes raw coal, filters out impurities, such as rocks and sediment, and crushes the ore to specified sizes for easier handling.

7.4 Coal Production

In 2024, total production of marketable coal decreased by 32% from 2023. As shown in Figure S7.1, subbituminous coal production was near zero in June 2024 with the decommissioning of the Genesee mine and the full conversion of the Capital Power Genesee generating station (the last coal-fired power plant in Alberta) to natural gas. Thermal and metallurgical bituminous coal will comprise most of Alberta's future total marketable coal production.

Figure S7.1 Alberta marketable coal production

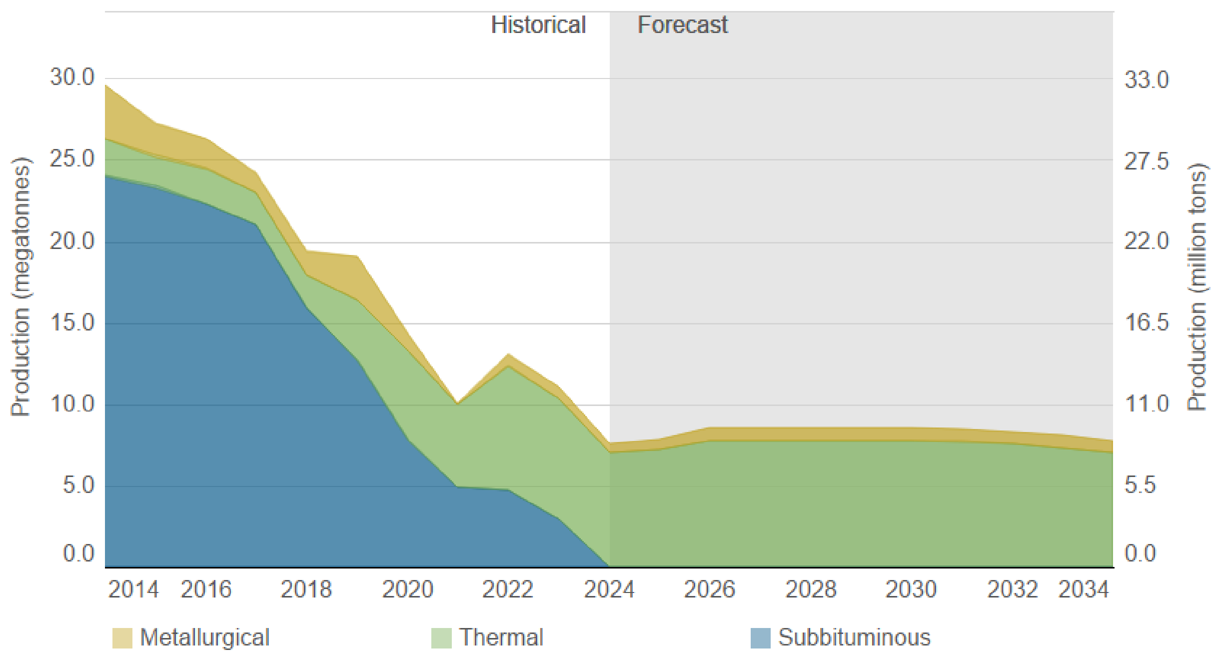


Table S7.1 Alberta marketable coal production (Mt)

Coal Type	2023	2024	2025	2026	2034
Subbituminous	2.93	0.02	0.02	0.02	0.02
Metallurgical bituminous	0.71	0.54	0.62	0.75	0.75
Thermal bituminous	7.43	7.02	7.22	7.77	7.02
Total	11.07	7.58	7.86	8.54	7.79

Any discrepancies are due to rounding.

Of the marketable coal produced in 2024,

- 0.3% was subbituminous,
- 92.6% was thermal bituminous, and
- 7.1% was metallurgical bituminous.

7.4.1 Subbituminous Coal

7.4.1.1 In 2024

Subbituminous coal production in Alberta accounts for 0.3% of the total marketable coal production in 2024. Production of subbituminous coal decreased by 99% in 2024 to 0.02 megatonnes (Mt). Coal production from the Genesee mine ended as the mine was decommissioned in June 2024, coinciding with the full conversion of the Capital Power Genesee generating station to natural gas. The use of coal to generate electricity has been phased out in Alberta several years ahead of the legislated 2030 deadline.

7.4.1.2 Forecast for 2025 to 2034

With the June 2024 closure of the Genesee mine, subbituminous coal production is expected to be near zero, with some production from the Dodds coal mine, which supplies coal for heating agricultural, residential, and industrial buildings throughout western Canada. Rising carbon costs, reducing emissions, and a commitment to use more renewables were significant factors in Alberta's transition away from coal-fired power generation.

7.4.2 Metallurgical Bituminous Coal

7.4.2.1 In 2024

Production of marketable metallurgical bituminous coal (called coking coal) decreased by 24% in 2024 compared with 2023 to 0.54 Mt due to lower coal prices.

7.4.3 Thermal Bituminous Coal

7.4.3.1 In 2024

Production of marketable thermal bituminous coal (called steaming coal) was down from 7.4 Mt to 7.0 Mt in 2024, a decrease of 6%.

7.4.3.2 Forecast for 2025 to 2034

In 2023, the Supreme Court of Canada ruled the designated projects section in the federal *Impact Assessment Act*, also known as Bill C-69, as unconstitutional. As a result, some coal companies have submitted applications for coal development in Alberta. In particular, the Mine 14 and the Vista Coal Mine Phase II Expansion coal projects will be allowed to undergo regulatory review because they were exempt from a provincial ministerial order banning coal development in the Rockies. In addition, in January 2025, the Alberta government lifted a ban on coal exploration in the Eastern Slopes of the Rocky Mountains for projects with existing exploration permits. Therefore, we have included these two projects in our production forecast but have applied a risk factor to account for the regulatory approvals process. The projection for bituminous coal production will grow slightly throughout the forecast.

In December 2024, the Government of Alberta announced they would engage with the coal industry to develop a new comprehensive coal policy, the *Alberta Coal Industry Modernization Initiative*. The initiative will focus on water protection, including best practices to prevent selenium from entering waterways, no open-pit mining in the foothills (Eastern Slopes), and prohibit mountaintop removal coal mining. The initiative will ensure responsible coal development and encourage new investment and job creation for Albertans.

Table S7.2 lists the coal mines in Alberta and their marketable production in 2024.

Table S7.2 Alberta coal mines and marketable coal production in 2024

Owner (grouped by coal type)	Mine	Location	Production (Mt)
Subbituminous coal			
Capital Power Corp./Westmoreland Coal Co.	Genesee	Warburg	0.00
Dodds Coal Mining Co. Ltd.	Dodds	Ryley	0.02
Subtotal			0.02
Metallurgical bituminous coal			
Grande Cache Coal Corp./Up Energy Development	Grande Cache	Grande Cache	0.54
Subtotal			0.54
Thermal bituminous coal			
Westmoreland Coal Co.	Coal Valley	Hinton	1.56
Coalspur Mines (Operations) Ltd.	Vista	Hinton	5.46
Subtotal			7.02
Overall Total			7.58

Any discrepancies are due to rounding.

Figure S7.2 shows Alberta’s coal mines and coal-fired power plants that were decommissioned or converted to natural gas.

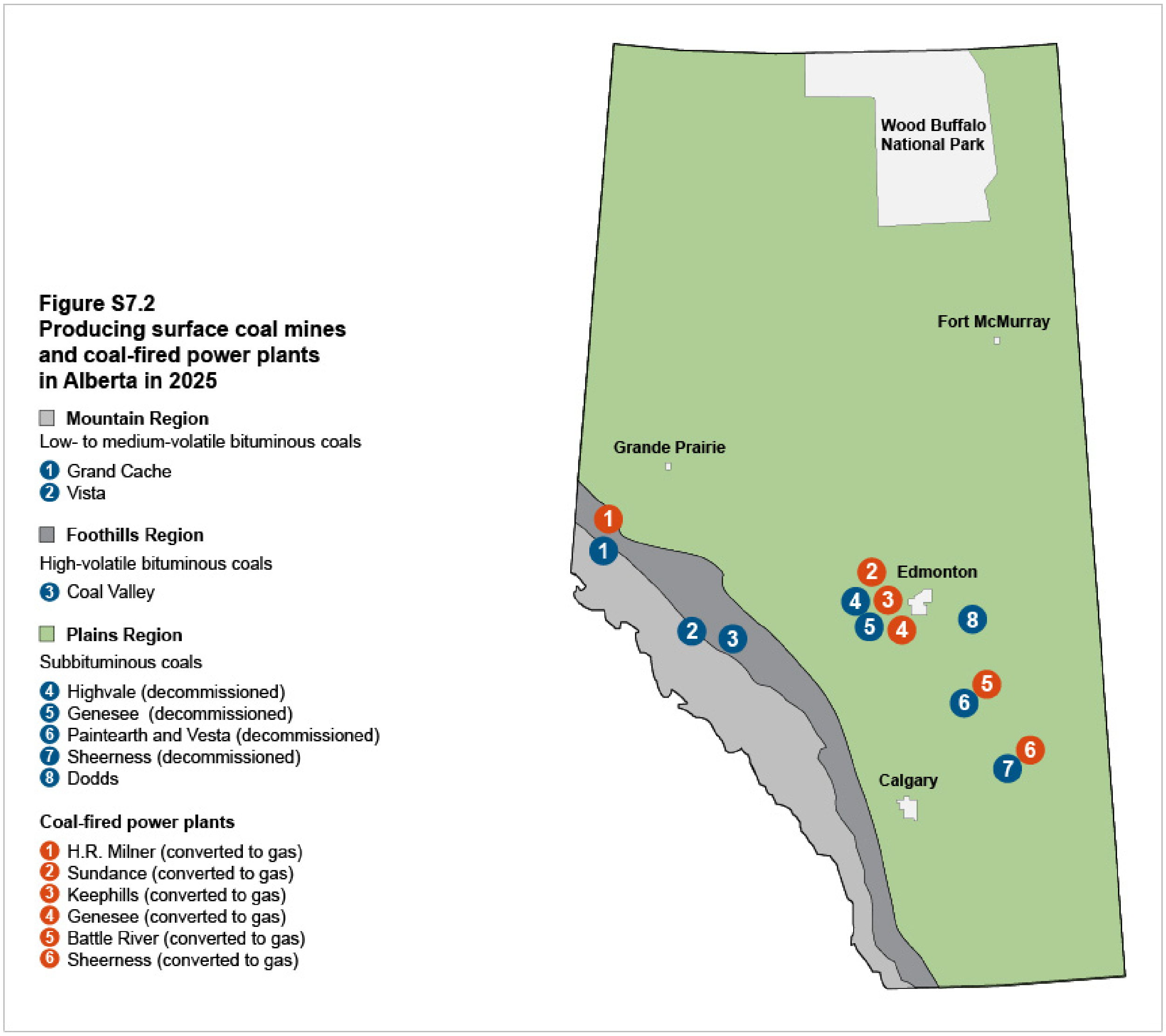


Figure S7.2
Producing surface coal mines and coal-fired power plants in Alberta in 2025

7.5 Coal Demand

Demand for subbituminous coal is expected to be near zero in Alberta as coal-fired power plants are either converted to natural gas or decommissioned.

International demand is expected to remain stable for metallurgical and thermal coals, especially from Asian markets and other developing regions over the forecast.

7.5.1 Subbituminous Coal

Demand for subbituminous coal is expected to be near zero in Alberta as coal-fired power plants are either converted to natural gas or decommissioned. The last coal-fired power plant in Alberta, Capital Power's Genesee generating station, was fully converted to natural gas in June 2024.

7.5.2 Retirement of Coal-Fired Power Plants

The retirement and conversion of Alberta's coal-fired power plant in 2024 significantly affected the subbituminous coal production, as nearly all subbituminous coal is for intraprovincial power generation.

In 2018, the Government of Canada amended the *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*, which set emissions performance standards for coal-fired electricity power plants by requiring all generation units to meet a performance standard of 420 tonnes of carbon dioxide per gigawatt hour of electricity produced (t of CO_2/GWh) by 2030. The amendments accelerated the phaseout of coal-fired power generation by 2030 to meet Canada's commitment to reduce overall greenhouse gas (GHG) emissions.

The outlook for subbituminous coal production has declined due to an accelerated phaseout of coal among electricity generators. TransAlta phased out its coal-fired power generation in Alberta in 2021, resulting in the closure of the Highvale mine. Heartland Generation also phased out its coal-fired power generation in 2021 with the closure of the Sheerness and Paintearth mines. Capital Power completed the conversion of its Genesee generating station to natural gas in 2024, prompting the closure of the Genesee mine.

7.5.3 Metallurgical Bituminous Coal

The Grande Cache mine produced 0.5 megatonnes (Mt) of metallurgical coal for export to South Korea in 2024. Asia remains Alberta's primary market for metallurgical coal. However, the long distance from the mine to market creates a competitive disadvantage for Alberta's exporting coal producers.

7.5.4 Thermal Bituminous Coal

Asia continues to be the largest source of demand for Alberta's thermal bituminous coal for power generation. Despite international demand, growth in exports beyond 2025 will depend on whether new projects in Alberta proceed.

7.5.5 Exports

Alberta's Coal Valley and Vista Coal mines produced 7.0 Mt of thermal bituminous coal in 2024, of which two countries accounted for most of the exports:

- South Korea: 4.0 Mt
- Japan: 2.4 Mt

According to the International Energy Agency, global coal demand in 2024 grew by 1%. Asia saw increased coal demand for power generation led by some emerging countries such as India, Vietnam, and Indonesia where demand for electricity grew alongside with population and economic growth. China is important to the global coal market, accounting for 56% of global demand, and will continue using coal for electricity generation while diversifying its power sector with renewables and nuclear. Other international suppliers are expected to supply most of the Asian demand for thermal bituminous coal.

7.6 Coal Methodology

Three grades of coal are produced in Alberta: subbituminous, metallurgical bituminous, and thermal bituminous. Forecasts are done for each type. Supply and demand fundamentals are considered, with the demand by coal-fired power plants essentially determining the supply of subbituminous coal.

7.6.1 Production Forecast

Production from each operating coal mine in the province is evaluated based on current market conditions and publicly available information.

The forecast is based on production from existing mines that are operational in the forecast period and the potential for growth for some of those mines. Only projects that have applied for provincial regulatory approval (permits, licences) will be considered in the forecast.

7.6.2 Demand Forecast

The AER's current forecast uses the coal-to-gas conversion schedule forecast from the most recent edition of *AESO 2024 Long-Term Outlook* and reflects any recent announcements by operators. The Alberta Electric System Operator forecasts the supply adequacy of electricity generation to meet provincial demand, given the scheduled retirement of all coal-fired power plants in Alberta by 2030.

All metallurgical and thermal bituminous coal production is assumed to leave Alberta, with final consumption elsewhere. The largest importers of Alberta's coal are monitored for steelmaking trends, power generation additions, and other trade factors that can influence demand.

7.6.3 Data

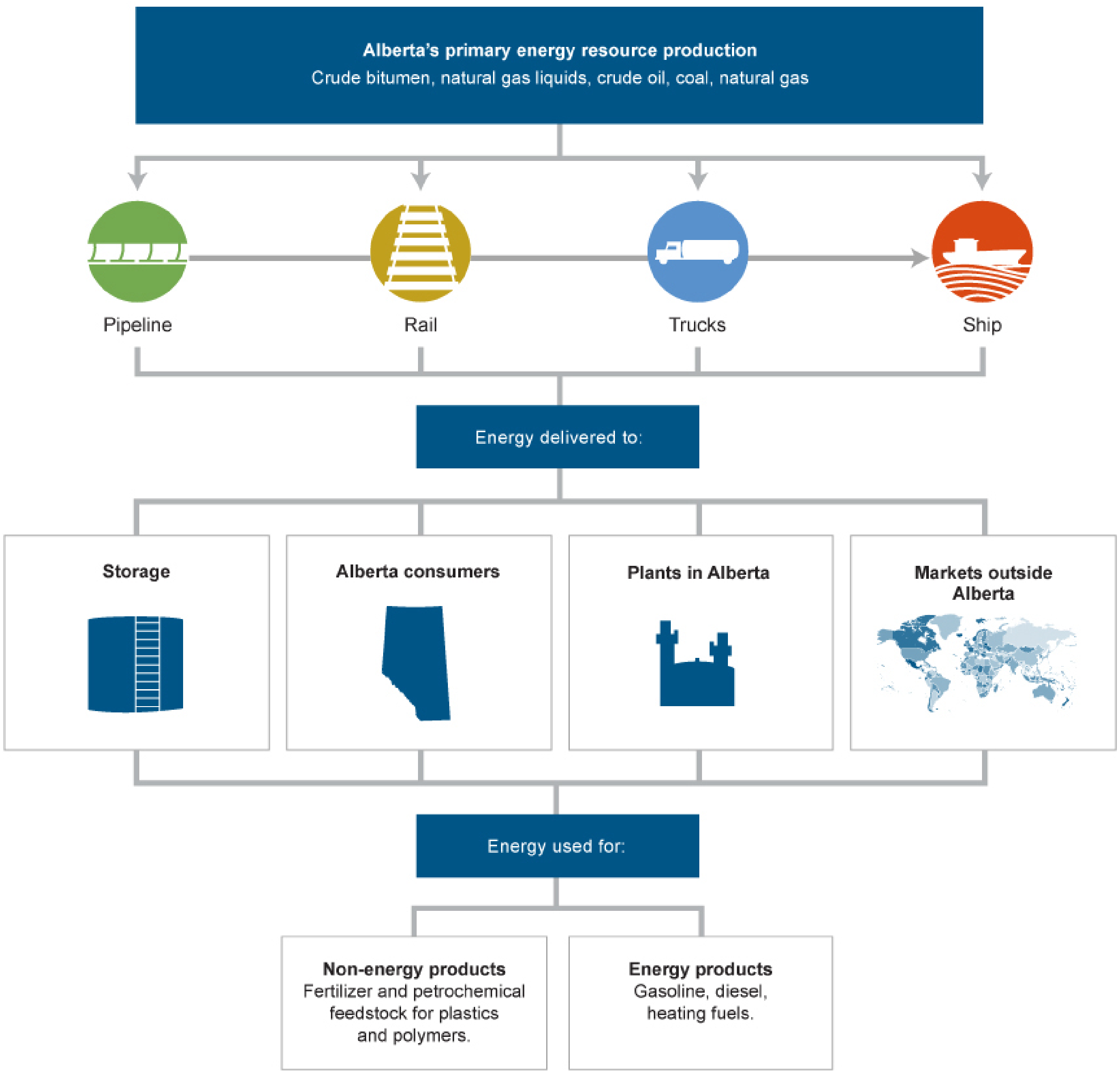
All 2024 data are reported by industry until the end of December and do not include any subsequent amendments. The AER uses historical data from the *ST26: Alberta Coal Industry Monthly Statistics* report for production and demand statistics.

8 Pipelines and Other Infrastructure

8.1 Summary

Oil and gas pipelines and railroads are among the transportation infrastructure needed to support the development of Alberta’s vast energy resources. Refineries, plants, and facilities turn these energy resources into marketable products (see Figure S8.1).

Figure S8.1 Schematic of Alberta energy resource flow



Pipelines

Thousands of kilometres of transportation infrastructure are needed to connect Alberta's energy commodities to markets inside and outside Alberta. A network of pipelines has been built solely to transport energy resources. Other infrastructure, such as railroads and electrical transmission lines, is shared with other industries and Albertans.

The AER regulates over 449 000 kilometres (km) of pipeline in Alberta. This includes 12 000 km of natural gas utility pipelines for which the AER conducts surveillance and inspections, incident response, and investigations (as per a memorandum of understanding with the Alberta Utilities Commission). The Canada Energy Regulator regulates oil and gas pipelines that cross provincial or federal borders.

Alberta's intraprovincial pipeline system is highly integrated and includes gathering, transmission, and distribution lines that transport hydrocarbons from producing areas to major distribution and processing centres within the province.

Pipeline gathering systems lower transportation costs versus rail and trucking; they reduce truck traffic and generate fewer safety and environmental concerns over product handling. Removal pipelines carry hydrocarbons to markets outside Alberta and are typically high-capacity pipelines traversing longer distances.

Oil Pipelines

In Alberta, most oil pipeline systems deliver oil to two central locations: Edmonton and Hardisty.

At Edmonton, pipelines transport crude oil to refineries in Alberta. Crude oil is also delivered to locations outside the province through Enbridge Inc.'s Mainline system and Trans Mountain Corporation's Trans Mountain pipeline.

At Hardisty, crude oil can enter the Alberta Clipper pipeline, part of Enbridge's Mainline system, for delivery to eastern destinations in Canada; TC Energy's Keystone pipeline for delivery to Illinois and Texas; or Enbridge's Express pipeline for delivery to the U.S. Rocky Mountains.

Transporting Heavier Crude Oil

Heavier crude oil, such as raw bitumen, will not naturally flow through a pipeline because of its high viscosity. It is typically mixed with a diluent to help it flow. Condensate and upgraded bitumen are the two main types of diluent used to lower the viscosity of raw bitumen for transport in pipelines. Naphtha, light crude oil, and butanes can also be used to get the bitumen to meet pipeline specifications. In some cases, heated pipelines are used to transport heavy bitumen.

The volume of diluent used depends on the viscosity of the crude oil and the type of diluent. Condensate is lighter than upgraded bitumen, meaning less condensate is needed to move bitumen through a pipeline. On average, heavy crude diluted with condensate will contain about 30% condensate, whereas heavy crude diluted with upgraded bitumen will contain up to 50% upgraded bitumen.

Typically, in Alberta, a small pipeline will transport condensate into the field, and a larger pipeline will transport the mix of heavy crude and condensate to a refinery where the condensate is usually recycled. When the condensate and bitumen mix is transported to markets outside Alberta, the condensate may be used as refinery feedstock or recycled and sent back to Alberta.

Natural Gas Pipelines

Raw natural gas, which includes other hydrocarbons and impurities, is transported from the wellhead by a gathering system to field processing plants. Field plants are usually near the gas source where contaminants, such as water and hydrogen sulphide, are removed. Natural gas liquids (NGLs) may also be removed. Companies may extract more NGLs than is needed to meet pipeline specifications to get full value for the NGL components.

Once the natural gas meets pipeline specifications, it is compressed for shipment via a large transmission pipeline. Natural gas flows under compression through the transmission system from areas of high pressure to low pressure. Once the gas reaches its end market, distribution companies reduce the pressure for delivery through local distribution networks.

Plants and Facilities

Upgraders

Upgraders are oil sands processing plants that upgrade bitumen into lighter hydrocarbon products. They chemically alter the bitumen either by adding hydrogen or by removing carbon. Sometimes, facilities do both. Upgrading improves the quality of the crude bitumen, producing a lighter, sweeter blend that can fetch a premium price.

In upgrading, most of the sulphur and other impurities contained in the bitumen are removed. The sulphur is either stockpiled or shipped to facilities that convert it to sulphuric acid, mainly used to manufacture fertilizers.

Upgrading also produces an off-gas that is high in NGLs and olefins. Companies have primarily used this off-gas as fuel in oil sands operations. They are now processing increasing volumes of off-gas to remove the NGLs and olefins, which are used as feedstock in the petrochemical industry.

Oil Refineries

Oil refineries use crude oil, upgraded and nonupgraded bitumen, and pentanes plus to produce a wide variety of refined petroleum products, such as gasoline and diesel.

Natural Gas and Natural Gas Liquids Processing Plants

Ethane and other NGLs are recovered mainly from natural gas processing. Gas reprocessing plants, often referred to as straddle plants, recover NGL components or NGL mix from marketable gas. They are usually situated on main gas transmission pipelines at border delivery points. Straddle plants remove most of the propane plus (C_3+) and ethane. The degree of recovery is 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 separated into its different components, such as propane, butane, and pentanes plus. A de-ethanizer tower with a turboexpander chills the natural gas to isolate ethane from other NGLs.

Ethane recovered at field processing plants, NGL fractionators, and straddle plants is shipped on the Alberta Ethane Gathering System to the Alberta ethane market.

Alberta's petrochemical industry is a major consumer of ethane, which it uses to produce ethylene and polyethylene. Ethylene is one of the building blocks in producing packaging material, ethylene glycol, and styrene. The petrochemical industry also produces many other products, such as fertilizer.

Railroads

North America's railroad network is extensive, linking almost all major cities and ports across the continent. This network allows the movement of products across borders and markets. Within Alberta, the railroad system crosses the province's major energy-producing regions. While pipelines allow shippers to access only certain markets, rail allows producers to place their product on railcars and ship it anywhere on the continent serviced by rail.

Trains are loaded at transloading facilities, which include pipeline-connected storage hubs and rail terminals. The oil industry typically uses a unit train, which carries only one type of commodity bound for one destination and generally has about 100 railcars. Demand for unit trains has grown rapidly in recent years because they can make a single nonstop run (they do not need to stop at different locations to offload different commodities).

8.2 Pipelines

8.2.1 Oil Pipelines

Alberta is serviced by major export lines that provide the bulk of export capacity leaving the province (see Figure S8.2).

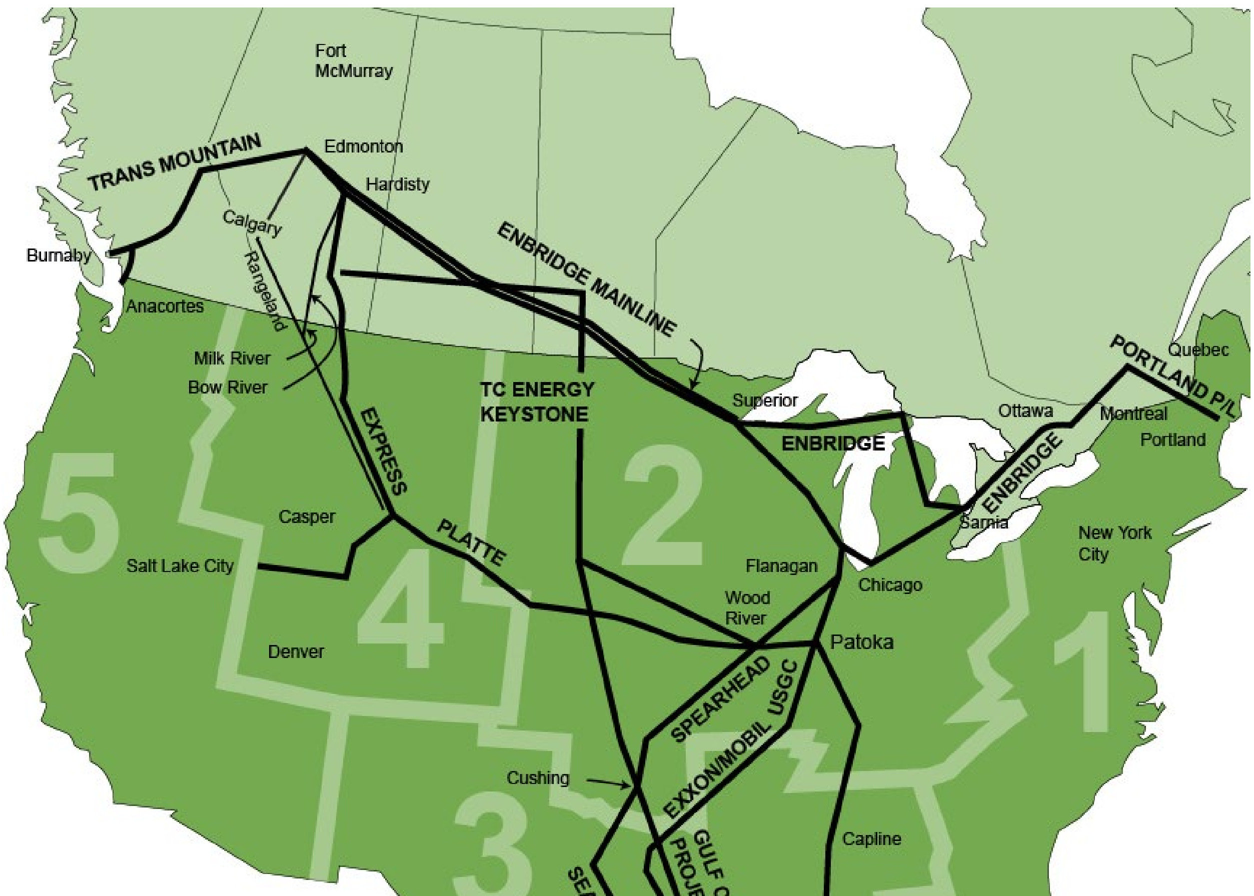


Figure S8.2
Selected Canadian and U.S. crude oil pipelines

Existing pipeline

5 Petroleum Administration Defense District (PADD)

Alberta has many interprovincial pipelines as listed in Table S8.1.

Table S8.1 Alberta's intraprovincial oil pipelines

Name	Destination	Capacity (10^3 m^3/d)	Capacity (10^3 bbl/d)
Canadian Natural Resources Limited (CNRL)			
Echo pipeline	Hardisty	12.0	75.5
Cenovus Energy			
Husky pipeline	Hardisty; Lloydminster	78.0	490.8
Enbridge Inc.			
Athabasca pipeline (Line 19)	Hardisty	90.6	570.0
Athabasca pipeline twin (Line 45)	Hardisty	127.1	800.0
AOC Hangingstone pipeline (Line 72)	near Fort McMurray	2.5	16.0
Line 73	near Fort McMurray	7.0	44.0
Norealis pipeline (Line 50)	near Fort McMurray	14.3	90.0
Waupisoo pipeline (Line 18)	Edmonton	87.4	550.0
Wood Buffalo pipeline (Line 75)	near Fort McMurray	87.4	550.0
Woodland pipeline (Line 49/70)	Edmonton	85.8	540.0
Line 21 (Norman Wells pipeline)	Zama	7.9	50.0
Gibson Energy			
Viking Pipeline	Hardisty	14.3	90.0
Inter Pipeline Ltd.			
Bow River	Milk River	28.6	180.0
Central Alberta	Edmonton	15.8	99.5
Cold Lake pipeline	Hardisty; Edmonton	190.7	1200.0
Corridor pipeline	Edmonton	73.9	465.0
Viking Connector	Edmonton	2.4	15.0
Pembina Pipeline Corporation			
Cheecham lateral pipeline	near Fort McMurray	36.5	230.0
Horizon pipeline	Edmonton	39.7	250.0
Nipisi pipeline	Edmonton	15.9	100.0
Syncrude pipeline	Edmonton	61.8	389.0
Plains Midstream Canada			
Rainbow I pipeline	Edmonton	35.0	220.3
Rangeland Midstream Canada			
Marten Hills Pipeline System	Edmonton	12.7	79.9
Suncor Energy			
Oil Sands pipeline	Edmonton	23.0	144.7
TC Energy			
Grand Rapids pipeline	Edmonton	143.0	900.0
Northern Courier pipeline	Fort McMurray	30.9	194.5
Wolf Midstream			
Access pipeline	Edmonton	63.6	400.2

8.2.2 Market Access

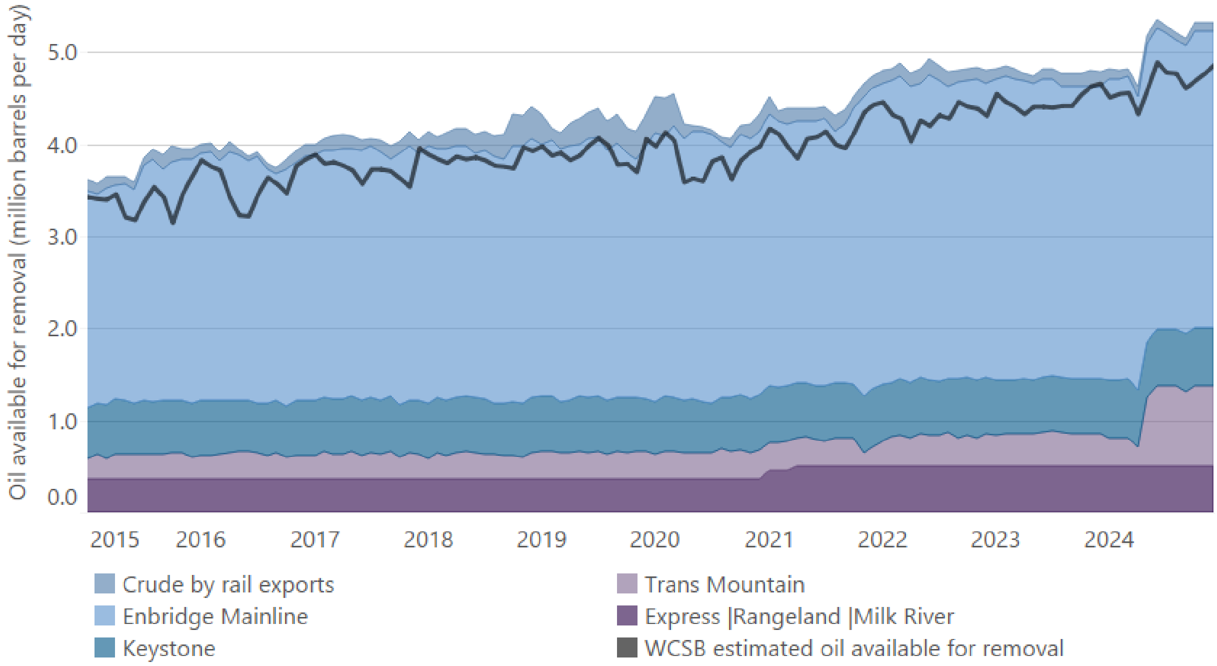
In 2024, the total pipeline design capacity to move oil from the Western Canadian Sedimentary Basin to outside markets was 851.4 thousand cubic metres per day (10^3 m^3/d) or 5358 thousand barrels per day (10^3 bbl/d). Table S8.2 lists the existing pipelines that transport oil from Alberta and their destinations and design capacities.

Table S8.2 Alberta's removal oil pipelines

Name	Destination	Capacity (10^3 m^3/d)	Capacity (10^3 bbl/d)
Enbridge Inc.			
Enbridge pipeline	Eastern Canada	532.3	3350.0
	U.S. East Coast		
	U.S. Midwest		
Express pipeline	U.S. Rocky Mountains	49.3	310.0
Trans Mountain Corporation			
Trans Mountain pipeline	British Columbia	141.4	890.0
	U.S. West Coast		
	Offshore		
Inter Pipeline			
Milk River pipeline	U.S. Rocky Mountains	15.6	98.0
Plains Midstream Canada			
Rangeland pipeline	U.S. Rocky Mountains	15.9	100.0
TC Energy			
Keystone pipeline	U.S. Midwest	96.9	610.0
		851.4	5358.0

In 2024, there was an average of 796 10^3 m^3/d (5007 10^3 bbl/d) of pipeline export capacity for oil from the Western Canadian Sedimentary Basin (Figure S8.3). This amount reflects the available capacity. The Trans Mountain pipeline expansion started up in May 2024, increasing the design capacity from 300 10^3 bbl/d to 890 10^3 bbl/d.

Figure S8.3 Western Canadian Sedimentary Basin (WSCB) estimated oil available for removal



Note: Data is from the Canada Energy Regulator. 90% utilization rate has been used for the Express, Rangeland, and Milk River pipelines. Enbridge Mainline, Keystone, and Trans Mountain pipelines reflect available capacity. Crude by rail exports includes the amount of oil shipped via rail.

8.2.3 North American Pipeline Projects

Table S8.3 lists selected proposed pipeline projects in North America and their anticipated start-up dates and capacities.

Table S8.3 Selected North American pipeline projects

Name	Anticipated start-up date	Total capacity (10^3 m^3/d)	Total capacity (10^3 bbl/d)
Enbridge Inc.			
Mainline expansion	TBD	31.8	200.0

TBD is to be determined.

8.2.4 Natural Gas Pipelines

Figure S8.4 shows the major gas pipeline systems in Canada and major export points for Alberta’s natural gas.

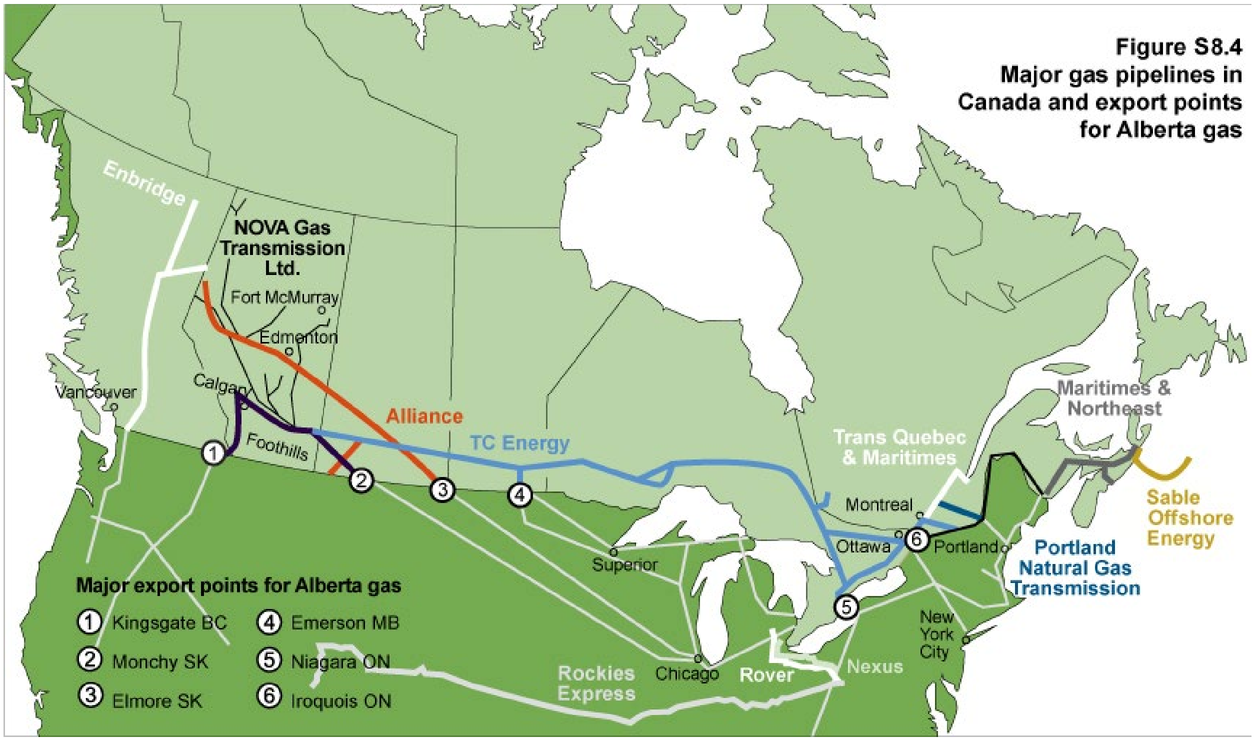


Table S8.4 lists Alberta's interprovincial pipelines, and Table 8.5 lists the removal and import pipelines.

Table S8.4 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
[a]Yellowhead Mainline	Fort Saskatchewan, AB	28.2
Enbridge Inc. & Pembina Pipeline Corporation		
Alliance	Steelman, SK	130.5
Suncor Energy		37.3
Suncor pipeline	Fort McMurray, AB	2.8
TC Energy		
Pioneer pipeline	TransAlta's Sundance and Keephills power stations	9.6
NOVA Gas Transmission Ltd.	Calgary	43.0
	Edmonton	57.0
	Oil Sands Delivery Area Kirby	36.0
	Oil Sands Delivery Area Liege	40.0
	Upstream of James River	330.0
	North and East	141.0
Foothills (Alberta system)	BC border	59.0

[a] Planned to be on-stream in 2027.

Table S8.5 Alberta's removal natural gas pipelines

Name	Destination	Capacity (10^6 m^3/d)
Alliance Pipeline		
Alliance	Illinois	45.0
TC Energy		
NGTL East Gate (Empress)	Saskatchewan	138.0
NGTL West Gate (BC border)	Southwestern AB	87.0

Source: Canada Energy Regulator.

8.2.5 Natural Gas Liquid Pipelines

Alberta has many pipelines transporting natural gas liquids, including ethane, butane, and condensate. Since 2004, demand for condensate has exceeded Alberta's supply because condensate is a common diluent for oil sands bitumen. Alberta now relies on imports of condensate to meet demand. Condensate imported from the United States is primarily through the Southern Lights pipeline (from Manhattan, Illinois, to Edmonton, Alberta) and the Cochin pipeline (from Kankakee, Illinois, to Fort Saskatchewan, Alberta). Alberta's diluent demand is expected to increase with growing oil sands production.

8.2.6 Ethane Gathering and Delivery Systems

Figure S8.5 shows the ethane gathering and delivery systems in Alberta.

Figure S8.5
Ethane gathering and delivery systems

8.2.7 Natural Gas Liquids Pipeline Capacity

Table S8.6 lists Alberta's interprovincial NGL pipelines, Table S8.7 lists the interprovincial NGL pipelines, and Table S8.8 lists the proposed NGL pipeline projects.

Table S8.6 Alberta's intraprovincial NGL pipelines

Name	Destination	Capacity (10^3 m^3/d)
Enbridge Inc.		
Norlite diluent pipeline (Line 74)	Edmonton; near Fort McMurray	34.6
Inter Pipeline Ltd.		
Boreal pipeline	Redwater	6.8
Polaris pipeline	Northern Alberta	206.6
Keyera Corp.		
Fort Saskatchewan condensate system	Edmonton; Fort Saskatchewan	47.7
Fort Saskatchewan pipeline system	Edmonton; Fort Saskatchewan	59.1
Keylink NGL gathering pipeline system	Fort Saskatchewan	3.5
Rimbey pipeline	Edmonton; Fort Saskatchewan	7.1
Keyera Corp. and Stonepeak Partners LP		
Key Access Pipeline System (KAPS)	NW Alberta; Fort Saskatchewan	55.6
Pembina Pipeline Corporation		
Alberta ethane gathering system	Petrochemical facilities in Alberta	52.4
Bonnie Glen pipeline	Edmonton	15.9
Brazeau/Caroline pipelines	Edmonton	9.5
Cremona pipeline	Rangeland pipeline in southern Alberta	7.9
Mitsue pipeline	North of Slave Lake	7.2
Pembina pipeline	Gathering pipelines in south-central Alberta	23.8
Swan Hills pipeline	Edmonton	17.5
Plains Midstream Canada		
Co-Ed pipeline system	Edmonton; Fort Saskatchewan	11.4
Rainbow II pipeline	Nipisi Terminal	5.6
Rangeland pipeline	Carway	7.9
Wolf Midstream		
Access pipeline	near Conklin	22.2

Table S8.7 Alberta's removal and import NGL pipelines

Name	Destination	Capacity (10^3 m^3/d)
Enbridge Inc.		
Southern Lights pipeline (Line 13)	Edmonton, AB	28.6
Pembina Pipeline Corporation		
Cochin pipeline	Fort Saskatchewan, AB	15.1
Peace and Northern NGL pipeline system	Edmonton, AB	174.8
Liquids gathering system	Pembina Northern NGL pipeline system (Taylor, BC)	6.1
Vantage pipeline	AEGS[a] in southern Alberta	10.8

[a] Alberta ethane gathering system.

Table S8.8 Alberta NGL pipeline projects

Name	Anticipated start-up date	Total capacity (10^3 m^3/d)	Total capacity (10^3 bbl/d)
Wolf Midstream			
NGL North Phase Two Expansion	2027	14.3	90.0

8.3 Plants and Facilities

Alberta has over 26 000 oil facilities and over 18 000 gas plants and gas facilities. In 2024, this facility count included

- 8 operating oil sands mines,
- 26 thermal in situ oil sands operations,
- 4 active bitumen upgraders,
- 5 refineries,
- 3 coal processing plants, and
- 4 producing coal mines.

8.3.1 Oil Sands Facilities

8.3.1.1 Mine Projects

Table S8.9 lists the company and project names of the eight operating oil sands mines in Alberta. Learn more in the crude bitumen_section.

Table S8.9 Operating oil sand mining projects in Alberta

Company	Project name
Canadian Natural Resources Limited	Horizon
	Muskeg River
	Jackpine
Imperial Oil Resources Limited	Kearl
Suncor Energy	Base/Millennium/North Steepbank
	Fort Hills
Syncrude	Aurora
	Mildred Lake

8.3.1.2 In Situ Schemes

Table S8.10 provides the company and project names of in situ operations in Alberta.

Table S8.10 Operating oil sand in situ schemes in Alberta*

Company	Scheme
Athabasca Oil Corporation	Leismer
	Hangingstone
Canadian Natural Resources Limited	Jackfish
	Primrose and Wolf Lake
	Kirby
	Peace River
Cenovus Energy	Christina Lake
	Foster Creek
	Sunrise
CNOOC Petroleum North America ULC	Long Lake
Connacher Oil and Gas Limited	Great Divide
ConocoPhillips Canada Resources	Surmont
Greenfire Resources Operating Corporation	Hangingstone Demonstration
	Hangingstone Expansion
Grizzly Oil Sands ULC	May River
Harvest Operations Corporation	BlackGold
Imperial Oil Resources Limited	Cold Lake
International Petroleum Corp. Canada	Blackrod
MEG Energy	Christina Lake
PetroChina Canada	MacKay River
Strathcona Resources Ltd.	Orion
	Tucker
	Lindbergh
Suncor Energy	MacKay River
	Firebag
Sunshine Oilsands Ltd.	West Ells

*SAGD and CCS Recovery Method.

8.3.2 Upgraders

Table S8.11 lists the average upgraded bitumen production in Alberta in 2024 by company.

Table S8.11 Average upgraded bitumen production in 2024

Company/project name	Product	(10^3 m^3/d)	(10^3 bbl/d)
Canadian Natural Resources Limited (CNRL) Horizon	Light sweet synthetic crude	39.9	251.1
Shell Canada Scotford	Sweet and heavy synthetic oil and intermediate refinery feedstock	50.6	318.4
Suncor Energy	Synthetic light sweet and medium sour crudes, including diesel	55.0	346.1
Syncrude	Light sweet synthetic crude	51.1	321.6
Total		196.6	1237.2

Any discrepancies are due to rounding.

8.3.3 Oil Refineries

There are 18 refineries in Canada, and 5 are in Alberta. These refineries have a combined refining capacity of 0.30 million cubic metres per day (10^6 m^3/d) or 1.9 million barrels per day (10^6 bbl/d). In 2024, the U.S. combined refining capacity was about 2.9 10^6 m^3/d (18.4 10^6 bbl/d). The United States has the highest number of complex refineries in the world, meaning they can process heavy sour crudes.

Alberta's oil reaches markets in Ontario and Quebec through Enbridge Inc.'s Mainline system. Western producers are limited to using rail to reach refineries in the Atlantic provinces, which is disadvantageous because rail is more expensive, and Alberta's oil competes with imports shipped from overseas.

In 2024, Alberta's refineries had an estimated total combined throughput of 91.4 thousand (10^3) m^3/d (575.0 10^3 bbl/d). Together, these refineries processed

- 56.9 10^3 m^3/d (357.9 10^3 bbl/d) of upgraded bitumen,
- 11.4 10^3 m^3/d (71.4 10^3 bbl/d) of nonupgraded bitumen,
- 17.8 10^3 m^3/d (112.3 10^3 bbl/d) of crude oil, and
- 5.3 10^3 m^3/d (33.4 10^3 bbl/d) of pentanes plus.

Table S8.12 lists the 2024 throughput for Alberta's refineries.

Table S8.12 Alberta refinery throughput in 2024

Refinery	(10^3 m^3/d)	(10^3 bbl/d)
Cenovus Energy Lloydminster	4.5	28.5
Imperial Oil Strathcona	30.3	190.9
North West Redwater Partnership Sturgeon	12.2	76.7
Suncor Energy Edmonton	24.6	154.9
Shell Canada Scotford	19.7	124.0
Any discrepanices are due to rounding.	91.4	575.0

Alberta's refinery utilization rate was 103% in 2024. The refinery utilization rate indicates how efficiently the refining complex operates, so the higher the utilization rate, the higher the production of refined products.

8.3.4 Natural Gas and Natural Gas Liquids Processing Plants

Alberta has

- over 400 active gas processing plants,
- 14 fractionation plants (separating out a mix of natural gas liquids [NGLs] into different components), and
- 7 straddle plants.

Figure S8.6 shows the different paths and processes that NGLs may take from the gas pools to the markets.

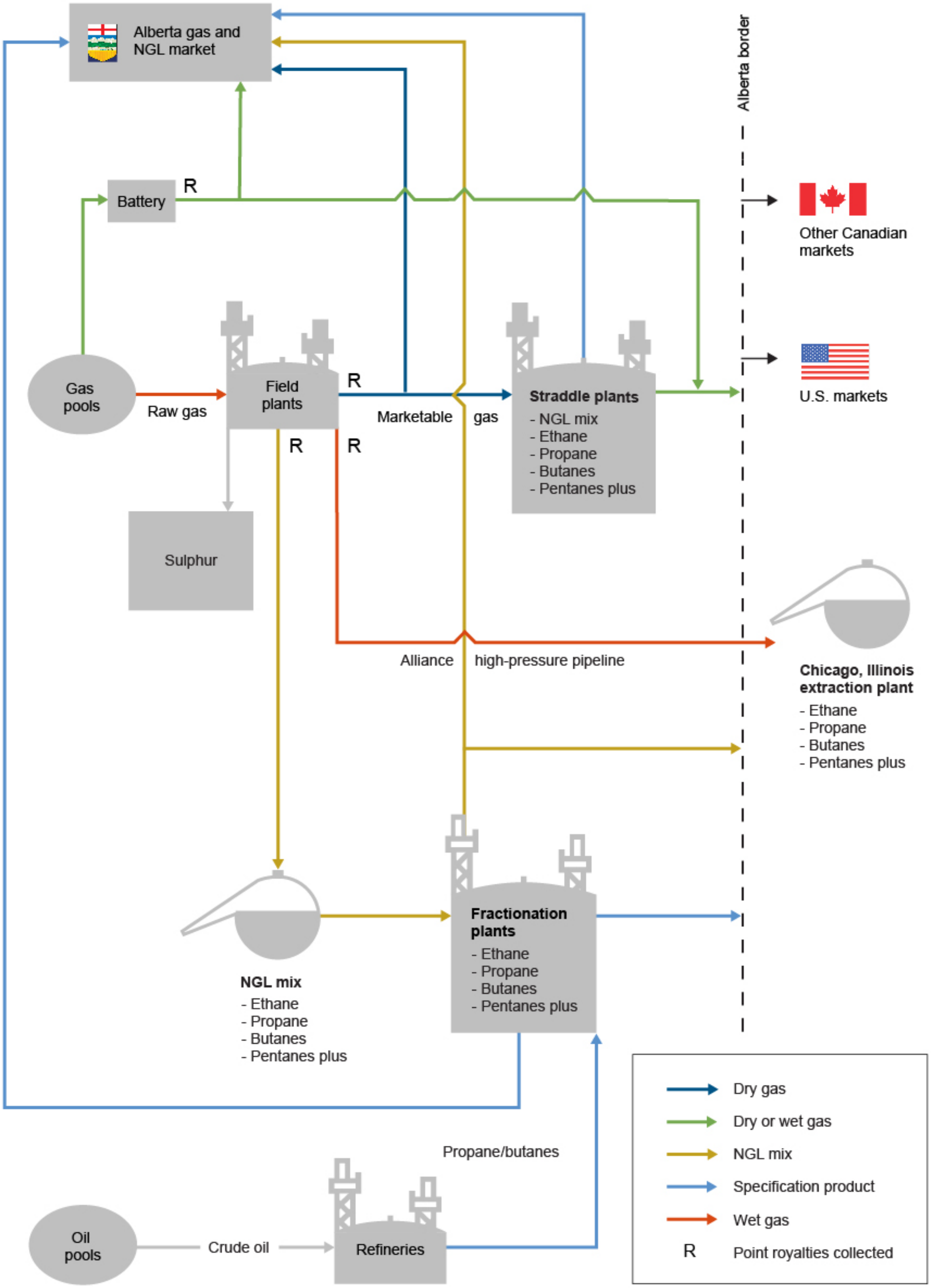
8.3.5 Western Canada Liquefied Natural Gas Projects

LNG Canada began constructing its Kitimat, B.C., terminal in 2019 to export liquefied natural gas (LNG) overseas and remain on track to start commercial operations in 2025.

This terminal will be the first in western Canada to export LNG overseas, enhancing Alberta's ability to access international markets. The first phase is expected to export up to 14 million tonnes per year (about 1.8 billion cubic feet per day); the proposed second phase will double export capacity to 28 million tonnes per year (about 3.7 billion cubic feet per day).

The Woodfibre LNG project is currently under construction and will be the world's first net-zero LNG export facility. Located near Squamish, B.C., the project will produce about 2.1 million tonnes of LNG annually, with a commercial operation date in 2027.

Figure S8.6 Schematic of Alberta NGL flow



8.3.6 Fractionation and Straddle Plants

Table S8.13 lists the fractionation plants in Alberta, and Table S8.14 the straddle plants.

Table S8.13 Fractionation plants in Alberta

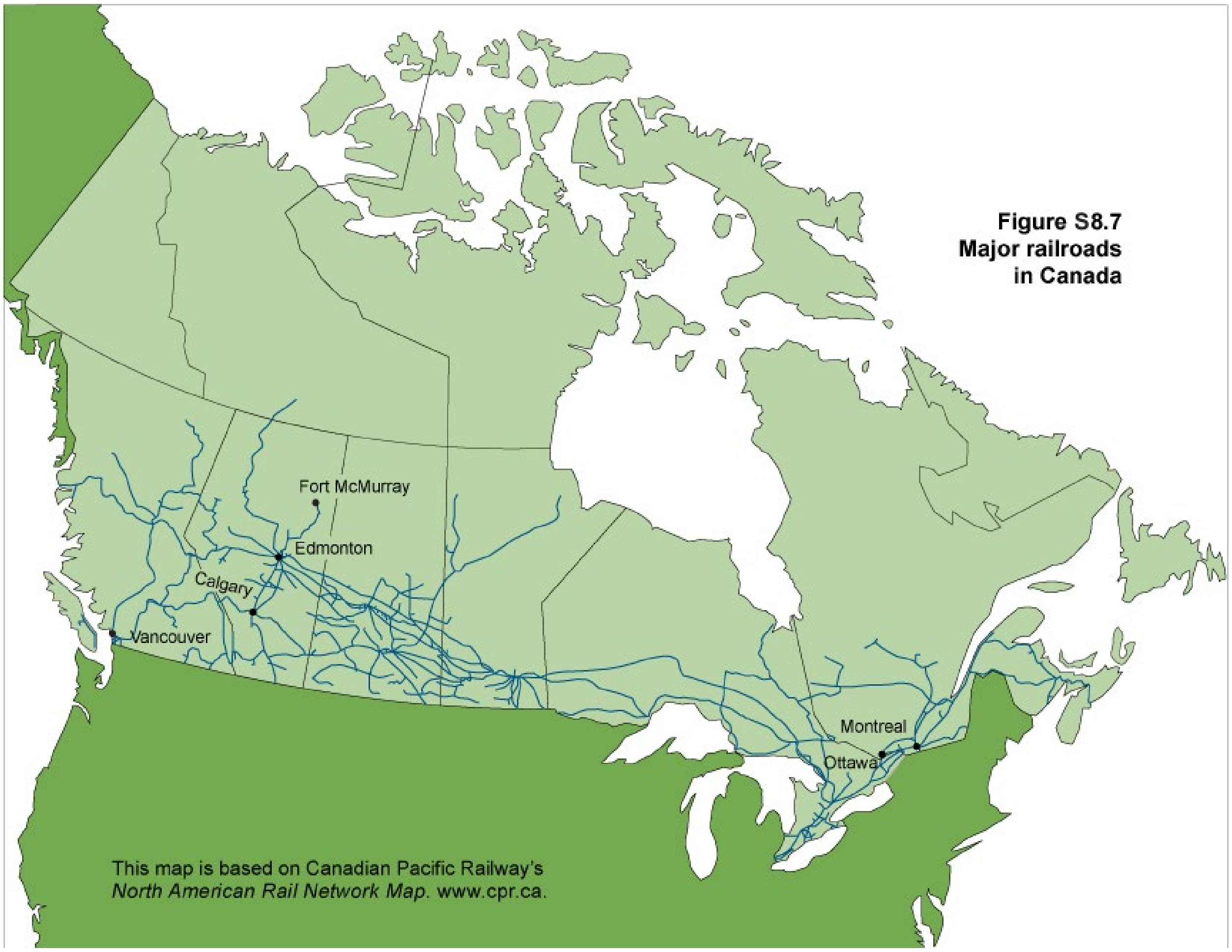
Area	Operator
Buck Creek	Plains Midstream Canada
Fort Saskatchewan	Dow Chemical Canada
	Keyera Corp.
	Pembina NGL Corporation
	Plains Midstream Canada
Edson	Pivotal Energy Partners Inc.
Harmattan-Elkton	AltaGas Ltd.
High Prairie	Plains Midstream Canada
Killam	Gibson Energy Inc.
Redwater	Pembina NGL Corporation
	Pembina NGL Corporation
	Pembina NGL Corporation
	Pembina NGL Corporation
Pembina	Tidewater Midstream and Infrastructure Ltd.

Table S8.14 Straddle plants in Alberta

Area	Operator
Cochrane	Inter Pipeline Extraction Ltd.
Ellerslie	AltaGas Ltd.
Empress	Pembina Gas Services Ltd.
Empress	Plains Midstream Canada
Empress 6	Plains Midstream Canada
Joffre	AltaGas Ltd.
Thornbury	Wolf NGL Inc.

8.4 Railroads

Figure S8.7 shows the major railroads in Canada.



Major rail terminals for oil and NGLs in Alberta and their capacities are shown in Figure S8.8. Table S8.15 lists the oil terminals, and Table S8.16 the NGL terminals.

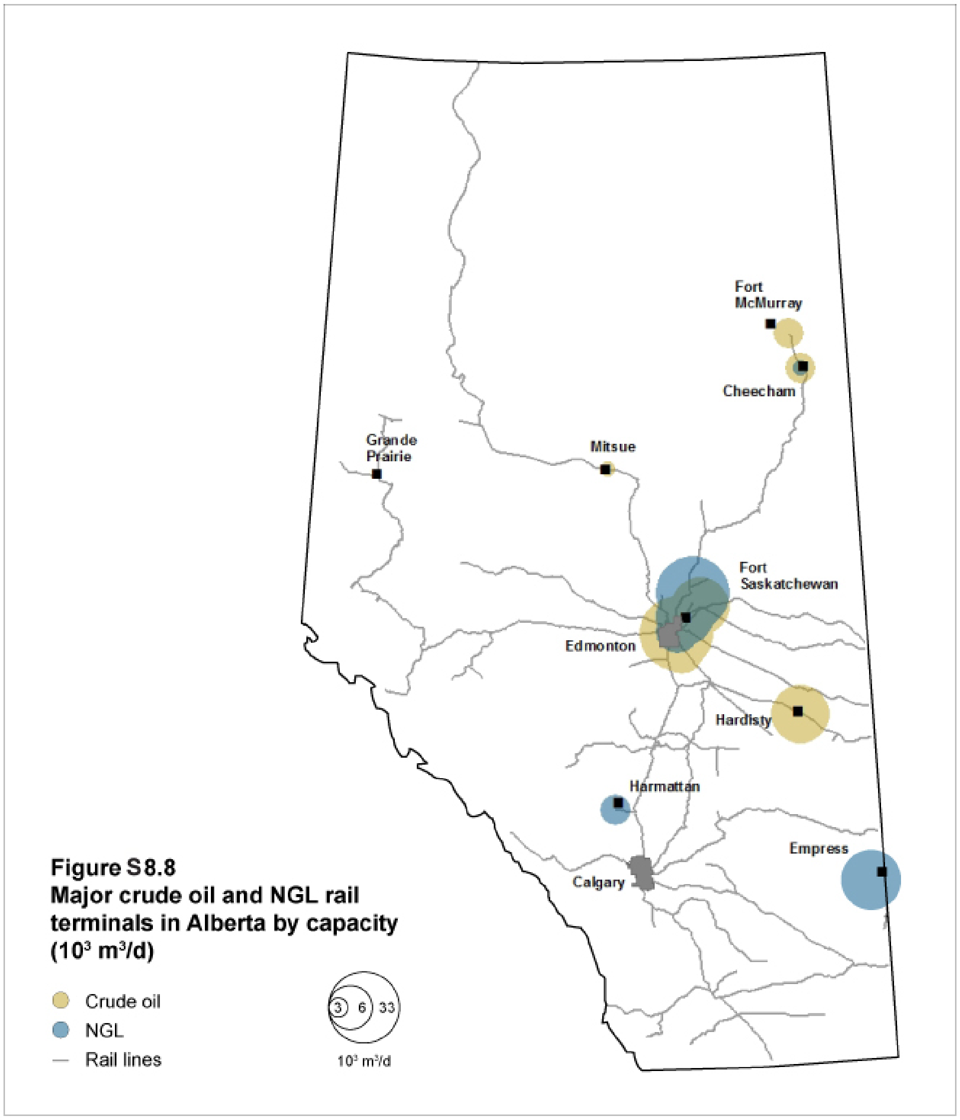


Figure S8.8
Major crude oil and NGL rail terminals in Alberta by capacity (10^3 m³/d)

Table S8.15 Major oil rail loading terminals in Alberta

Location	Operator	Capacity (10^3 m^3/d)	Capacity (10^3 bbl/d)
Fort McMurray/ Falher	Altex Energy	5.2	33.0
Bruderheim	Cenovus Energy	15.9	100.0
Peace River	Elbow River	4.4	27.5
Edmonton/Hardisty	Gibson Energy Inc.	40.8	257.0
Conklin	Grizzly/Gulfport	1.6	10.0
Edmonton/Anzac	Keyera Corp	10.2	64.0
Sherwood Park/Fort Saskatchewan	Pembina Pipeline Corporation	39.7	250.0
Reno	Savage Services	4.0	25.0
High Praire	Secure Energy	3.0	19.0
Tilley/Whitecourt	TORQ	2.5	16.0

Source: Oil Sands Magazine.

Table S8.16 Major NGL rail loading terminals in Alberta

Location	Operator	Capacity (10^3 m^3/d)
Harmattan	AltaGas Ltd.	5.6
Edmonton	Keyera Corp.	5.4
Fort Saskatchewan	Keyera Corp.	7.9
Josephburg	Keyera Corp.	6.7
Fort Saskatchewan	Keyera Corp.	6.4
Redwater	Pembina Pipeline Corporation	23.8
Fort Saskatchewan	Plains Midstream Canada	9.5
Empress	Spectra Energy Corp.	10.0

Source: Oil Sands Magazine.

9 Emerging Resources

9.1 Overview

The Alberta Energy Regulator's (AER's) mandate has expanded to include new areas of resource development, such as geothermal, brine-hosted mineral resources (including lithium) and rock-hosted mineral resources. This expansion is part of the Alberta government's *Alberta Recovery Plan* to diversify the economy and accelerate growth in new and emerging resources. The AER also regulates helium production and energy-related facilities producing hydrogen. We have set up a regulatory framework for these emerging resources and are working to understand the development of these resources and map the province's resource potential.

9.1.1 Hydrogen

Hydrogen is an energy carrier and one of the most abundant elements in the solar system. Hydrogen is a colourless, odourless, and flammable gas found almost everywhere on Earth but only bonded with other elements, such as carbon, nitrogen, and oxygen.

Hydrogen applications are diverse, including residential and commercial heating, power generation, energy storage, transportation, and industrial processes (e.g., fertilizers and bitumen upgrading).

Hydrogen in Alberta is derived mainly from natural gas. The carbon dioxide produced by the process is either vented to the atmosphere or captured and stored for future use or permanently sequestered.

9.1.2 Geothermal

Geothermal energy is the natural heat energy found deep within the Earth. It is a renewable energy resource with minimal environmental and carbon footprints. Geothermal energy can provide reliable baseload power with fewer fluctuations in output than other forms of renewable energy because the heat from the Earth's core is always available.

As public policies target opportunities to reduce the carbon footprint, we expect geothermal energy to gain a larger share of the energy mix.

Companies produce geothermal energy using two basic methods: open- and closed-loop technology.

- Open-loop technology relies on hot or warm groundwater as the heat source. Once the heat is extracted, the cooled water is either reinjected into the geothermal reservoir for reheating or expelled from the system.

- Closed-loop technology relies on a working fluid circulated through a closed wellbore in a hot subsurface formation. The closed wellbore can be two to seven kilometres below the surface, possibly deeper. The heated fluid circulates to the surface where the heat is extracted. The cooled fluid is circulated back through the wellbore for reheating.

9.1.3 Helium

Helium is the second-lightest and second-most abundant element in the solar system. It is created by the natural radioactive decay of heavy radioactive elements like thorium and uranium within the Earth's mantle and crust. Helium is a non-renewable resource, primarily attributed to its tendency to escape into the atmosphere upon release—a consequence of its inherent physical properties. Helium can be produced as a by-product of natural gas production or directly from dedicated helium wells in certain geological formations.

Helium has many uses in scientific research, medical technology, and industrial applications. Helium is used to cool superconducting magnets, such as those in magnetic resonance imaging scanners. Another well-known use of helium is as a lifting gas in balloons and airships.

9.1.4 Lithium

Lithium is considered the lightest of all metals and the lightest solid element under standard conditions. It does not naturally occur as a pure element but in compounds, usually as ionic compounds in mineral deposits, including underground brines in Alberta.

Historically, lithium was used for ceramics and glass, lubricating greases, polymer production, aluminum smelting, etc. Today, the production of lithium-ion batteries for electric vehicles, electronics, and grid power storage is driving the capital expenditure in lithium extraction.

Companies and research groups in Alberta are testing direct lithium extraction (DLE) technology. DLE allows access to Alberta's lithium-brine potential in existing oil and gas reservoirs. This technology enables the recovery of lithium concentrate, which is the first step in the lithium value chain.

9.1.5 Tariff Scenarios

Because of significant uncertainty, particularly regarding U.S. tariff policies, this year's report examines two scenarios: a short-term tariff uncertainty scenario (base case) and a one-year tariff scenario (tariff case). The primary difference between these scenarios lies in their tariff assumptions.

- **Base case**: This scenario assumes business as usual and no tariffs. However, the U.S. tariff threats on energy products (oil and gas) persist throughout the first half of 2025 but are ultimately averted through diplomatic negotiations by midyear. Consequently, energy supply and demand are minimally affected
- **Tariff case**: This scenario assumes a 10% U.S. tariff on energy products (oil and gas) and 25% tariffs on other Canadian goods imposed in the first half of 2025 despite diplomatic efforts. This scenario includes subsequent U.S. and Canadian retaliatory tariffs, other nontariff measures,[10] and additional U.S. tariffs on other trading partners. All tariffs and nontariff measures between Canada and the United States persist until the end of the first quarter of 2026 before mostly being phased out as the review or renegotiation of the Canada-United States-Mexico Agreement. It is expected tariffs will have some long-term effects and structural changes to the global economy (changes in trade and investment flows).

These tariff assumptions affect prices, costs, commodity profitability, investment, supply and demand, project risk factors, and commercial start dates (where applicable) for most chapters of the report, including comparisons of the outcomes of these scenarios.

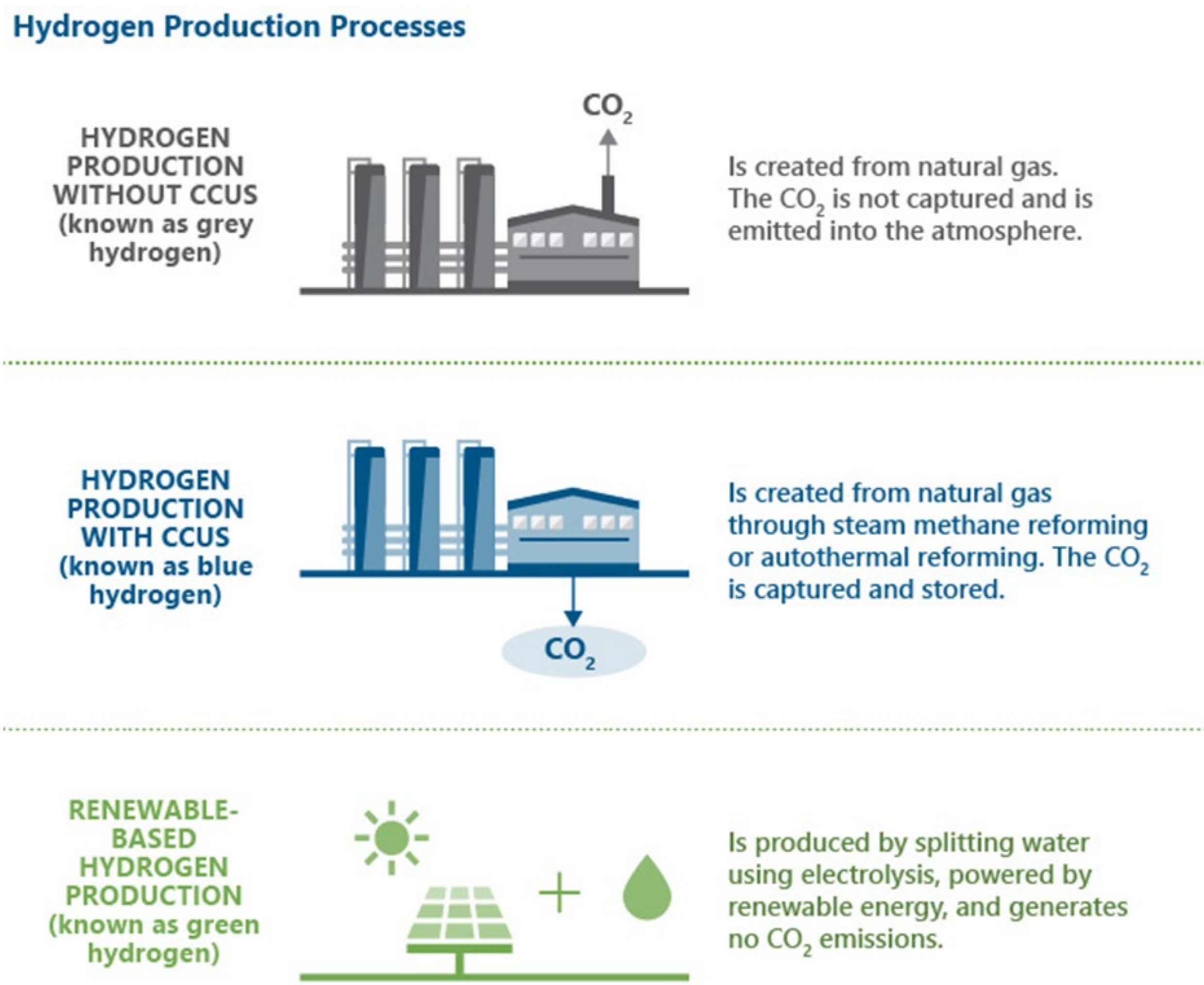
9.2 Hydrogen

9.2.1 What is Hydrogen

Hydrogen is an energy carrier and one of the most abundant elements on Earth. Hydrogen is a colourless, odourless, and flammable gas found almost everywhere on Earth but only bonded with other elements, such as carbon, nitrogen, and oxygen.

Hydrogen can be produced from a variety of sources using different technologies. Some common sources include natural gas and water. In Alberta, hydrogen production is mainly produced from natural gas. This is typically achieved through steam methane reforming or autothermal reforming methods. These methods introduce high-temperature steam and a catalyst to methane, producing hydrogen, carbon monoxide, and carbon dioxide (CO_2). With additional processing, carbon monoxide is converted to CO_2. The figure below shows hydrogen production pathways and their by-products.

[10] Nontariff measures can include quotas or restrictions on imported goods (i.e., liquor), export taxes on electricity, and changes in consumer and business behaviour (i.e., buying Canadian).



Alberta Energy Regulator

There is an opportunity for hydrogen to replace fossil fuels as a carbon-free energy source. Hydrogen-powered electric vehicles have zero emissions, whereas gasoline vehicles emit carbon monoxide, CO_2, hydrocarbons, and nitrogen oxides.

The refining and industrial sectors drive global hydrogen demand. However, demand for hydrogen is expected to expand to other industry sectors, such as transportation, power generation, and heating. In parallel with the growth in hydrogen demand, uses for CO_2 captured from hydrogen production with carbon capture, utilization, and storage (CCUS) continue to develop.

9.2.2 Federal and Provincial Government Hydrogen Plan

The federal government has set a hydrogen strategy for Canada, leading to actions that will establish hydrogen production to achieve Canada's goal of net zero emissions and be a leader in clean and renewable fuels by 2050. The near-term demand for hydrogen will be influenced by the market readiness of applications and commercial applications (e.g., heavy-duty trucks, power generation, industrial feedstock, and heat for industrial sites).

Alberta developed a hydrogen road map to enable large-scale production of low-cost and low-carbon intensity hydrogen. The Alberta Industrial Heartland region near Edmonton has the advantage of becoming one of the first hydrogen-producing hubs in Canada. It has access to plentiful natural gas sites, potential CCUS sites, and an existing hydrogen pipeline. Leveraging the existing infrastructure will reduce the upfront production costs of new hydrogen projects. Other Alberta advantages include experience and technical capacity in producing, handling, and using hydrogen at the industrial scale, positioning the province as the largest hydrogen producer in Canada today. Alberta has the necessary skilled workforce that pioneered the Canadian energy industry and is poised to support the emerging clean hydrogen economy.

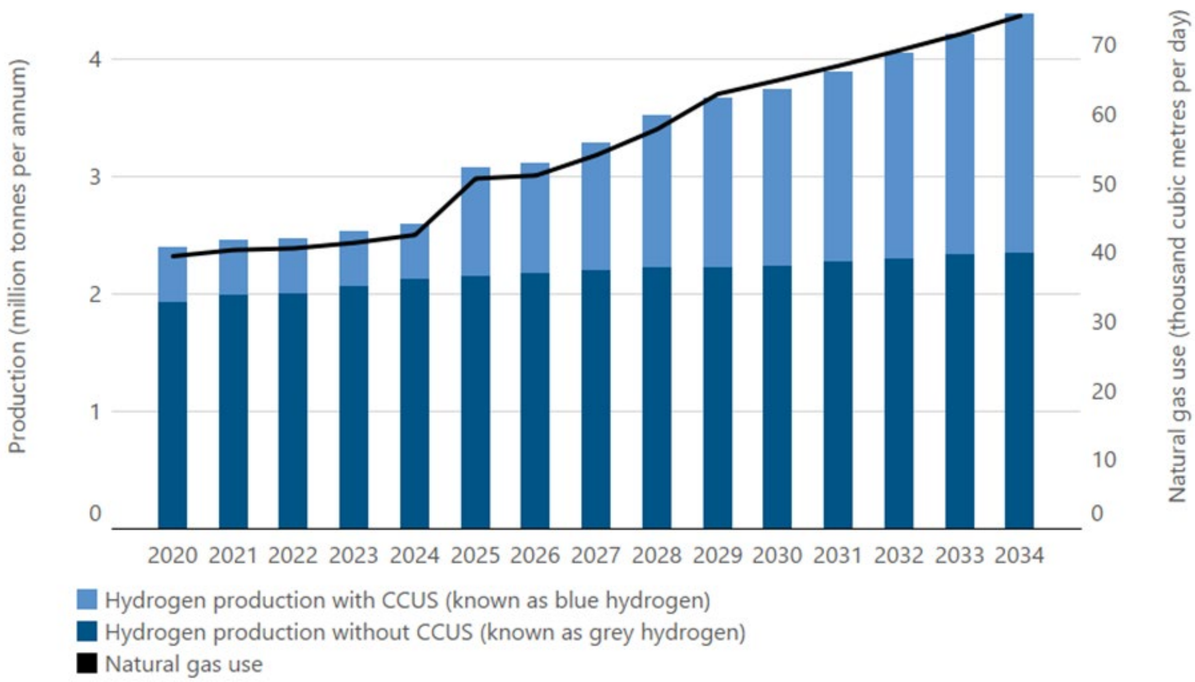
As global energy policies shift, particularly in the United States, where key initiatives such as the Paris Agreement withdrawal and halted hydrogen funding under the Inflation Reduction Act have signalled declining support-Canada and Alberta have a unique opportunity to incentivize greater hydrogen investment.

9.2.3 Production in 2024 and Base Case Forecast

In 2024, hydrogen production without CCUS was estimated to be 2.1 million tonnes, while hydrogen production with CCUS reached 0.5 million tonnes. The hydrogen production base case forecast involves weighing the risks based on the likelihood of meeting the project’s operational date and production capacity.

Figure S9.1 shows the forecast for hydrogen production in Alberta.

Figure S9.1 Alberta hydrogen production



Note: Based on 2020 hydrogen production data from the Alberta Hydrogen Roadmap and publicly available information, we estimate and forecast the hydrogen production. CCUS represents Carbon Capture, Utilization, and Storage.

Current uses of hydrogen in Alberta include industrial applications, such as chemical production, oil refining, bitumen upgrading, and nitrogen-based fertilizer production. ATCO is blending hydrogen with natural gas for residential heating systems in the Fort Saskatchewan area. Other potential uses through pilot projects are for transportation, including hydrogen fuel-cell vehicles (cars, buses, trucks) and hydrogen co-combustion engines primarily for heavy-duty applications.

9.2.4 Projects

Several companies have announced hydrogen projects in Alberta:

- Air Products' first hydrogen liquefaction facility with CCUS in western Canada is planned to begin commercial production in 2025, with plans to produce up to 1500 tonnes of hydrogen per day.
- Pembina Pipeline and Marubeni Corporation plan to build a low-carbon ammonia and hydrogen plant near Fort Saskatchewan. The facility will produce one million tons of blue ammonia annually for export to Asia.

- Linde is investing over $2 billion to build and operate a world-scale integrated clean hydrogen and atmospheric gases facility in Alberta. The facility will supply clean hydrogen to Dow's Path2Zero project and other industrial customers.
- Suncor and ATCO announced they are jointly building a production facility for clean hydrogen in the Alberta Industrial Heartland region. The project, awaiting investment decision this year, is expected to produce about 300 000 tonnes of hydrogen per year.
- Hydrogen Canada Corp. plans to build a blue hydrogen and ammonia facility in Alberta for export to Asia. The project, expected to begin operation in 2028, will produce up to 500 tonnes of hydrogen per day when fully operational.

Several pilot projects across the province are exploring new deployment applications and methods of cost-effective clean hydrogen production:

- Ekona Power received a $79 million equity investment to commercialize its low-cost clean hydrogen production technology.
- The Invest Alberta Corporation, Alberta Transportation, and the Canadian Infrastructure Bank have signed a memorandum of understanding to build a Calgary to Banff hydrogen-powered rail passenger project. The project is currently under design.
- ATCO and Qualico are conducting a feasibility study funded by the Alberta Hydrogen Centre of Excellence to develop a hundred per cent pure hydrogen community in Strathcona County.

9.2.5 One-Year Tariff Scenario (Tariff Case)

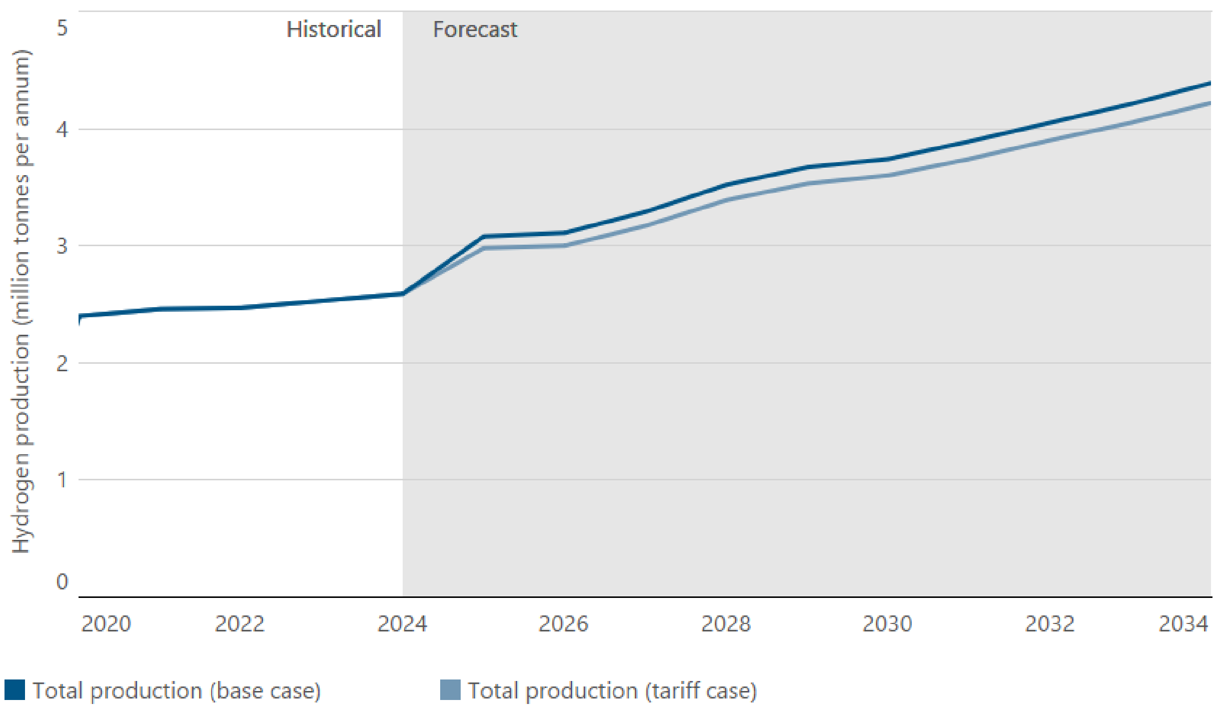
The potential of U.S. tariffs on Canadian goods is expected to create short-term market disruptions and investment uncertainty.

Despite the short-term challenges that U.S. tariffs may impose, key hydrogen projects are expected to continue advancing. Air Products' hydrogen facility is planned to begin production this year. The facility has secured a contract to supply hydrogen to Imperial Oil's new renewable diesel plant, which is scheduled to start operation this year and support the supply of low-carbon fuels for British Columbia's transportation sector. Although, Dow has announced a delay to its Path2Zero project, the company remains committed to its long-term execution. Furthermore, Alberta currently does not export any hydrogen internationally. These developments indicate that tariffs may cause minimal disruptions to the long-term outlook for hydrogen production.

Overall, hydrogen production under the tariff case is expected to decline slightly to 3.0 million tonnes in 2025 compared with the base case forecast of 3.1 million tonnes. As tariffs are removed in 2026, production is projected to increase over the forecast period. It is estimated to reach 4.2 million tonnes by 2034, 4% below the base case forecast.

Figure S9.2 shows the hydrogen production base case and tariff case forecasts.

Figure S9.2 Alberta total hydrogen production (base case vs. tariff case)



9.2.6 Limitations or Risks to the Outlook

Future construction costs for hydrogen facilities with CCUS are expected to be lower. Hydrogen production is expected to become competitive as carbon taxes increase in the coming years. The economics of the hydrogen industry depend on climate change policies and government support. These dependencies and current high investment costs would probably affect short-term investment decisions.

As we navigate the evolving landscape, continued attention to regulatory frameworks and technological advancement will be critical in shaping the trajectory of the hydrogen industry in Alberta.

9.3 Geothermal

9.3.1 What is Geothermal

Geothermal is a renewable energy resource found in rocks and fluids deep beneath the Earth's surface that can be harnessed for heating and electricity generation. The Earth's thermal energy comes from two sources: residual heat from the Earth's formation and heat from the decay of radioactive elements, mostly uranium, thorium, and potassium. Radioactive decay is the main source of heat in the Earth's crust.

Geothermal energy is produced and used based on the geothermal system and the quality of the resource in place. "A geothermal system is made up of three main elements: a heat source, a reservoir, and a fluid, which is the carrier that transfers the heat" (Dickson and Fanelli 2003)[11]. Some geothermal systems are endowed with naturally occurring hot aquifers (a hydrothermal system), whereas other systems create artificial reservoirs by injecting water into hot, dry rock to extract heat (enhanced geothermal system). Geothermal can be categorized into high-, medium-, or low-temperature resources. Medium- and high-temperature resources are more suitable for power generation, whereas low-temperature resources are suitable for heating and other applications. Alberta geology supports mostly low and medium temperatures ranging from 80°C to 170°C.

Some geothermal systems harness the Earth's heat from a few metres underground, while others require drilling deep wells. Based on the geothermal system and technology, there are three possible applications: electricity generation, geothermal heat pumps, and direct-use applications (e.g., industrial or commercial uses of heat).

9.3.2 Regulatory Framework for Geothermal Development

The Government of Alberta (GoA) enacted the *Geothermal Resource Development Act* (*GRDA*) in December 2021. The *GRDA* establishes a regulatory framework administered by the AER for the responsible development of geothermal resources and related wells and facilities in Alberta. The *GRDA* covers deep geothermal resources naturally occurring below the base of groundwater protection, while shallow geo-exchanges remain regulated by Alberta Environment and Protected Areas.

In June and August 2022, the GoA released the *Geothermal Resource Development Rules* (*GRDR*), and the AER released Directive 089: Geothermal Resource Development. Effective August 15, 2022, the *GRDR*, and effective February 7, 2025, the updated *Directive 089* set out

[11] Dickson, Mary H., and Mario Fanelli. 2003. Geothermal energy: utilization and technology. United Nations Educational, Scientific and Cultural Organization.

the conditions and requirements for industry to develop geothermal resources from project initiation to closure, including new provisions for converting oil and gas wells to geothermal wells and extending the Licensee Management Program to include geothermal developments.

Alberta has a competitive advantage over many other geothermal producers globally. Alberta has access to innovative drilling technologies, with a highly developed oil and gas skill set and a robust subsurface data set essential to a successful geothermal industry. There is a potential opportunity to repurpose Alberta’s existing wells; geothermal wells can be alongside oil and gas wells.

9.3.3 Alberta and Federal Incentive Programs Relating to Geothermal

The provincial and federal governments have geothermal incentive programs to promote geothermal energy development. A few of these programs are listed below:

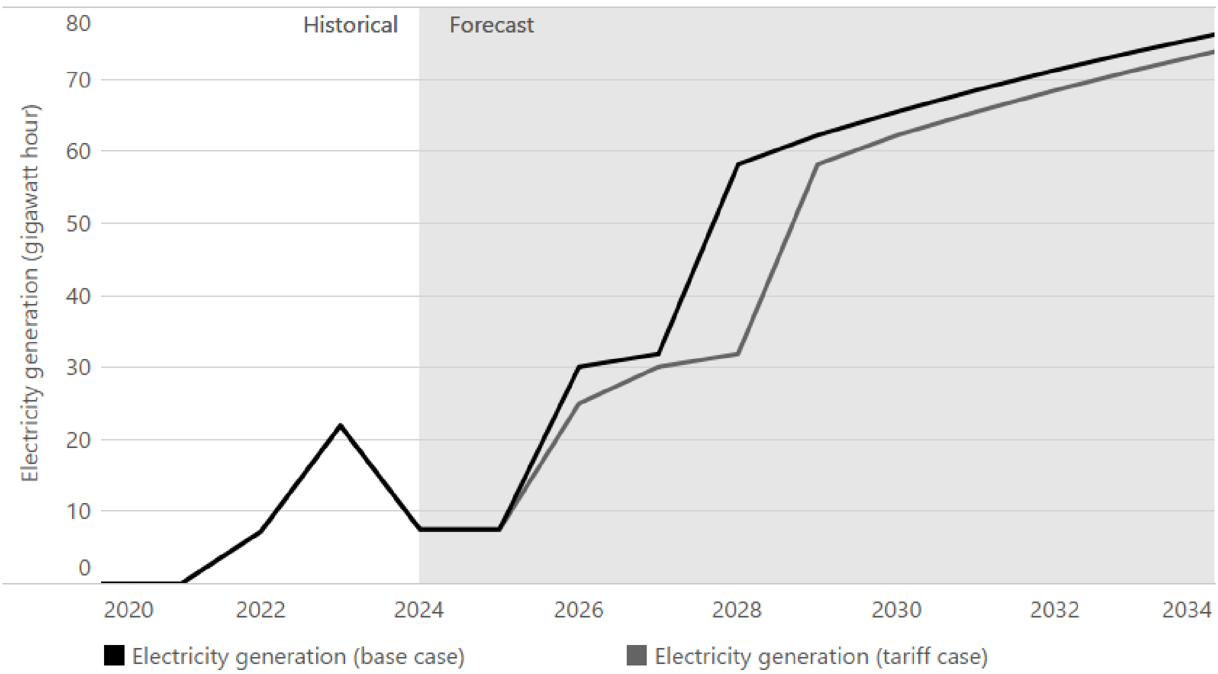
- Alberta Innovates (Renewable and Alternative Energy Program): Provides funding and support for projects developing and commercializing clean and sustainable energy technologies. Project funding can range from 25% to 50% of the total project costs and typically does not exceed $2 million per project.
- Emissions Reduction Alberta (Technology Funding Program): Provided financial support and incentives to promote clean energy technologies, including geothermal in Alberta.
- Alberta Indigenous Opportunities Corporation (AIOC): The organization provides financial support for Indigenous-led renewable energy projects and capacity building. An AIOC loan guarantee reduces the risks to lenders if an investor fails to meet its commitment to repay.
- Smart Renewable and Electricity Pathways Program: A federal government program focused on advancing renewable energy and smart grid technologies to modernize Canada's electricity systems, enhance energy efficiency, and reduce greenhouse gas emissions.
- Investing in Canada Infrastructure Program for green infrastructure: A federal government program that funds environmentally sustainable projects, such as geothermal.

9.3.4 Production in 2024 and Base Case Forecast

In 2024, an estimated 7.5 gigawatt hours (GWh) of geothermal electricity was generated in Alberta. This represents a decline from the previous year, primarily due to technical issues and financial constraints affecting the profitability and operational efficiency of geothermal projects. We considered higher risk factors for the existing projects due to their status. Looking ahead, we anticipate a compound annual growth rate of 26% in geothermal electricity generation throughout the base case forecast period, with production expected to reach 76.2 GWh by 2034 (see Figure S9.3). The production forecast involves weighing the likelihood of projects meeting their operational date and production capacity. Compared with last year's forecast, we downgraded our final year projection by 35%, reflecting significant development risks and the currently unfavourable economics of geothermal projects.

Figure S9.3 shows the geothermal electricity generation base case and tariff case forecasts.

Figure S9.3 Alberta geothermal electricity generation (base case vs. tariff case)



Note: Data was revised using new available information.

9.3.5 One-Year Tariff Scenario (Tariff Case)

Under the tariff case, the impacts on the geothermal energy sector lead to a short-term decline in power generation—17% in 2026, 6% in 2027, and a significant 45% in 2028 compared with the base case. These reductions stem from increased project risks and potential delays in development timelines, resulting in lower production capacity. In the long term, while power generation stabilizes, initial setbacks may slow growth overall and the expansion of geothermal infrastructure. By 2034, production under the tariff case remains 3% below the base case.

9.3.6 Projects

Several companies in Alberta have announced geothermal projects:

- No. 1 Geothermal Limited Partnership owns the Alberta No. 1 geothermal energy project developed by Terrapin Geothermics. The proposed project includes an electricity power plant, a district heating system, and several geothermal wells at a depth of four kilometres. When completed, the project capacity will be 10 MW of clean baseload electricity and 985 terajoules per year of heat.

- The Novus Earth Latitude 53 project is a 4 km deep closed-loop system that proposes to deliver geothermal energy for direct-use heat and electricity generation in Hinton, Alberta. When completed, the project capacity will be 3.1 MW of electricity.
- E2E Energy Solutions aims to power and heat the town of Rainbow Lake entirely with geothermal renewable energy by 2028. This project, which will generate 50 to 100 MW of power, represents a significant step towards sustainable energy solutions.

Numerous companies in Alberta are pioneering breakthrough technologies. For example, Algar Geothermal is developing a more efficient geothermal technology that better retains heat and reduces heat loss. Additionally, the Wonder Valley project, a partnership between O'Leary Ventures and the Municipal District of Greenview, aims to build off-grid natural gas and geothermal power infrastructure to support the world's largest AI data centre industrial park.

9.3.7 Alberta's Shallow and Deep Geothermal Potential

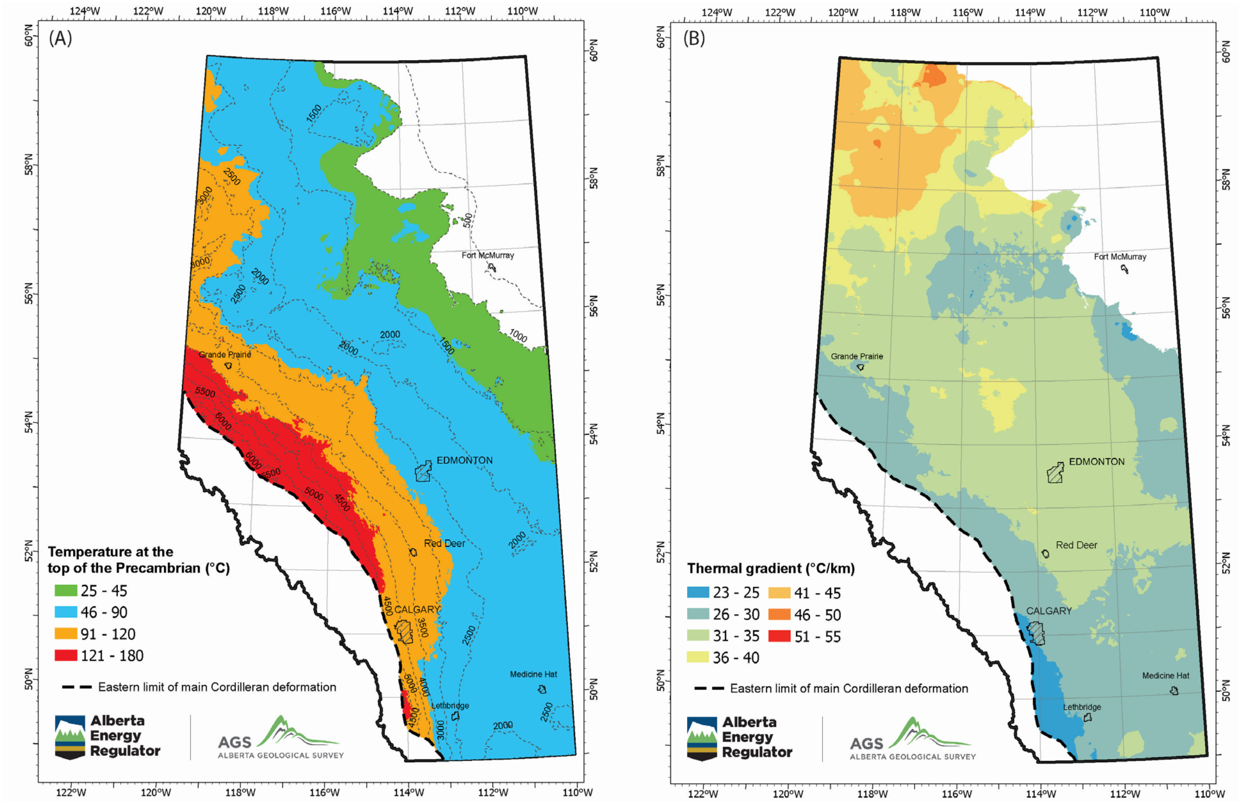
Alberta has considerable geothermal energy potential, with resources suitable for heating and electricity generation. Geothermal resources are classified as shallow or deep, depending on their temperature and depth. Although deeper resources tend to be hotter, this relationship varies based on local geological conditions. Traditional geothermal systems target naturally porous and permeable rock formations where hot water can flow into a wellbore and to the surface. Newer geothermal systems, such as closed-loop, rely on heat transfer from the rocks to a working fluid through conduction. Enhanced systems use artificial stimulation to extract heat from dry rock.

Shallow geothermal sources have temperatures below 90°C and are commonly used for direct heating in homes, greenhouses, aquaculture, and industry. Geothermal heat pump systems typically function below 45°C and use the ground to store and retrieve heat. A temperature range of 45°C to 90°C is suitable for direct heat use in district energy networks, agricultural operations, and other medium-temperature heating needs. Deep geothermal systems target temperatures above 90°C, typically at depths of 2 to 4 kilometres (see the image below). These systems generate electricity using special power plants or provide high-temperature heat for industrial processes. In areas of northwestern Alberta, and in some parts of west-central Alberta, the underground temperature changes more with depth and usable heat may be accessible at shallower depths.

The Alberta Geological Survey (AGS) has published the Geothermal Atlas of Alberta to support geothermal resource evaluation and mapping. The atlas is the first in Canada province-wide, formation-scale geothermal favourability mapping application. This first edition is now publicly available on the AGS website. The atlas uses data from Alberta's extensive oil and gas drilling history to assess three key geological parameters: subsurface temperature, the presence of fluids, and fluid storage capacity. The atlas highlights three geological units with promising deep geothermal potential (see below). For more information on the methodology of resource estimates, see the technical documentation in the *Geothermal Atlas of Alberta*.

- The Leduc Formation is estimated to contain about 4.06 trillion gigajoules (GJ) of heat in place (HIP), 66 gigawatts (GW) of gross thermal power, and 8.97 GW of gross electrical power capacity.
- The Swan Hills and Slave Point Formations combined are estimated to hold 1.86 trillion GJ of HIP, 36.82 GW of gross thermal power, and 7.0 GW of gross electrical power capacity.
- The Granite Wash is estimated to contain 522 billion GJ of HIP, 9.45 GW of gross thermal power, and 1.36 GW of gross electrical power capacity.

Even deeper, the Precambrian basement rock, which is hot, dry, and dense, also has potential for geothermal energy. In parts of western Alberta, modelled temperatures at the top of the basement exceed 180°C (shown in the map below), where electricity generation could be more efficient. These conditions make the basement a promising target for advanced geothermal technologies (e.g., closed-loop systems and enhanced geothermal systems). While resource estimation for the Precambrian basement rock requires a different approach than that used for sedimentary formations, the AGS is assessing the viability of the Precambrian rock for geothermal development.



9.3.8 Limitations or Risks to the Outlook

Geothermal energy is not as economically viable as wind or solar. The pace of geothermal commercialization in Alberta could slow because of competition from lower-cost, lower-risk renewable alternatives. According to the latest International Energy Agency (IEA) report published in December 2024, geothermal energy faces significant development risks. However, up to 80% of the investment required in a geothermal project involves capacity and skills that available in the oil and gas industry.

9.4 Helium

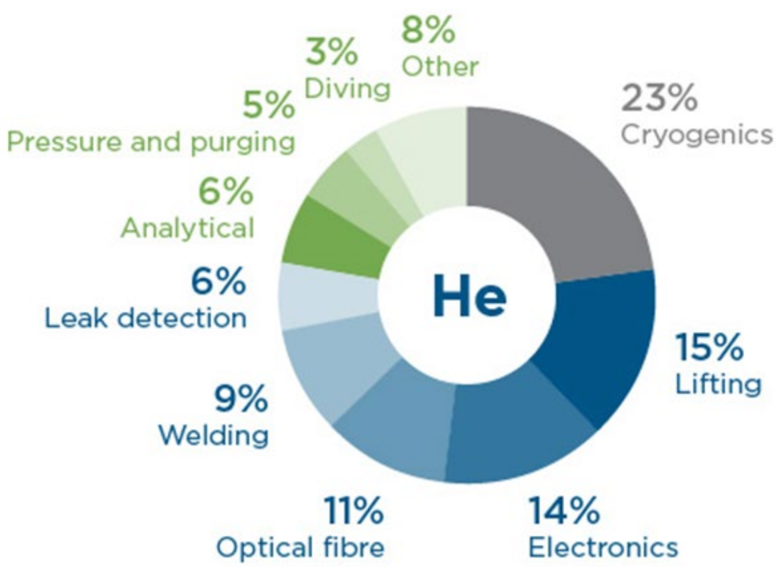
9.4.1 What is Helium

Helium is a naturally occurring colourless and odourless inert gas produced by the decay of uranium and thorium within the Earth's mantle and crust. It is a non-renewable resource that cannot be manufactured.

Helium can be found in oil and gas reservoirs. While helium can be extracted from the atmosphere, the process is expensive. However, when helium is trapped in the subsurface, it can accumulate in underground reservoirs, making it more cost-effective to extract. Helium is generally found in low concentrations (below 0.1%), and its extraction can be profitable when concentrations exceed 0.3%. However, project feasibility depends on the processing cost, the helium price, and market proximity.

Helium has many uses, including magnetic resonance imaging (cryogenics), lifting (use in balloons), electronics, optical fibre, welding, leak detection, and more (see image below). There are many applications where helium cannot be substituted, indicating a strong and stable demand over the coming years.

Global helium demand by end use



Source: Canada Energy Regulator

The depletion of helium reserves in the mid-continental U.S. region raises concerns about domestic supply. Because helium being an indispensable resource in various critical industries, it highlights the need for strategic resource management and exploration in Alberta.

9.4.2 Royalty Program and Alberta's Advantages

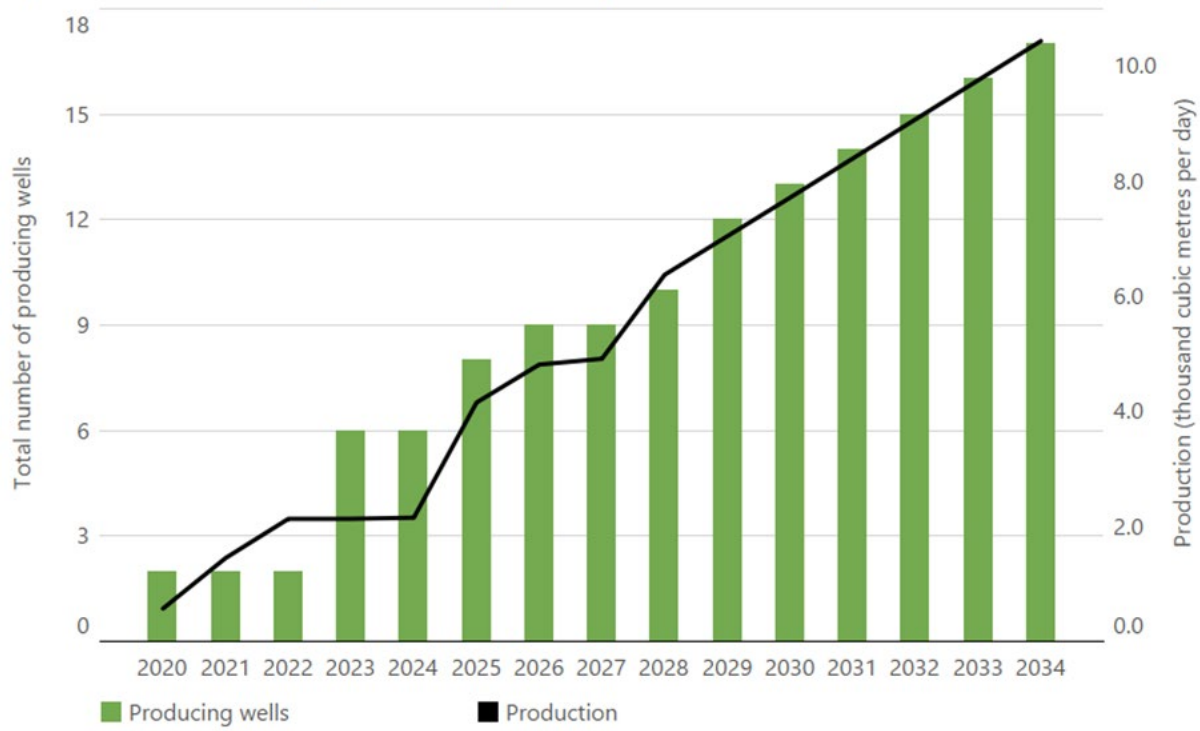
The helium royalty is regulated under the *Natural Gas Royalty Regulation*. In May 2020, the Ministry of Energy and Minerals introduced a 4.25% royalty rate for helium. Hence, operators producing helium are required to report monthly production volumes and monthly average selling prices.

Alberta has several competitive advantages in becoming a key supplier of helium. These advantages include the province's helium reserves located where oil and gas drilling has occurred, easy access to the United States (the world's largest consumer of helium), well-positioned infrastructure, and industry expertise. Current development activity for helium is focused on the southern part of the province.

9.4.3 Production in 2024 and Base Case Forecast

In 2024, helium production was 2.2 thousand cubic metres per day (10^3 m^3/d) from six producing wells (see Figure S9.4). Under the base case, production is forecast to reach 10.4 10^3 m^3/d from 17 wells by 2034. The production and well forecasts involve weighing the risks based on the likelihood of meeting the project's operational date and production capacity.

Figure S9.4 Alberta helium production and producing wells



9.4.4 Projects

- Thor Resources, Weil Group, and Royal Helium's Steveville purification facility were the source of helium production in 2024.
- First Helium, Global Helium, Avanti Helium Corp are currently conducting tests for developing helium projects in Alberta, with wells expected to be placed on production in the coming years.

9.4.5 Alberta Resource Potential

- Helium can be produced as a by-product of natural gas. Alberta is one of the leading natural gas producers in Canada; the province is in a great position to become a major helium producer.

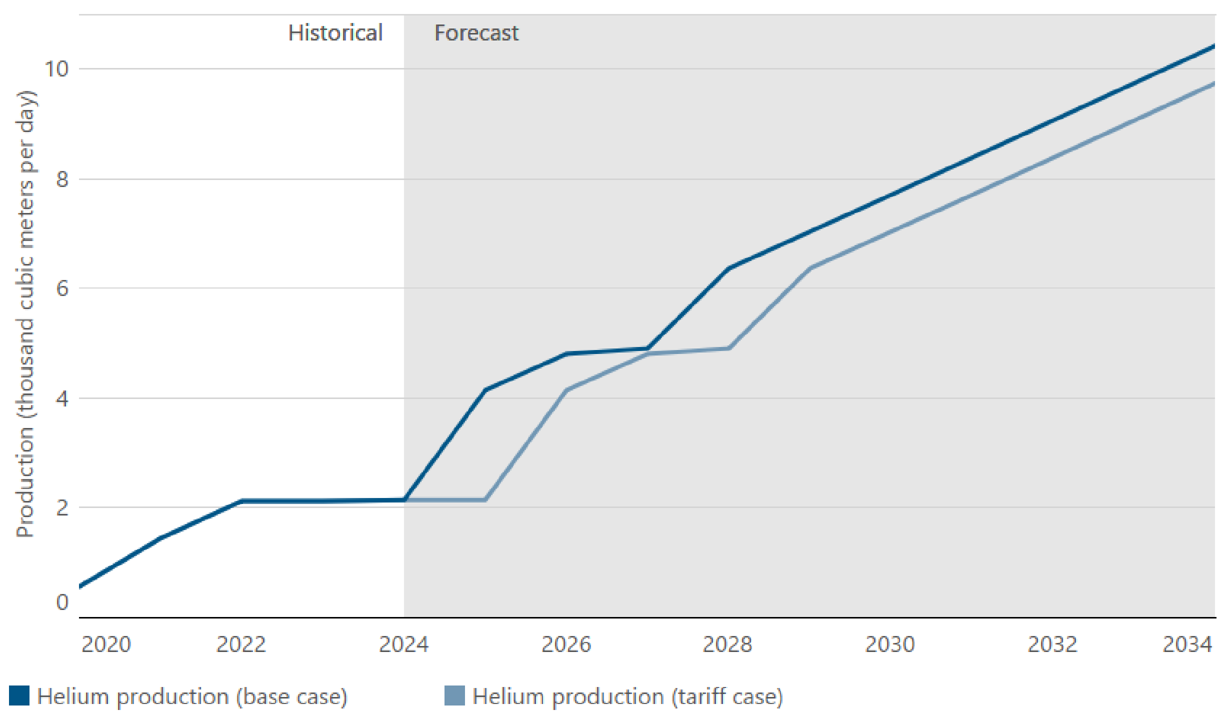
- Alberta's helium resource potential comes from profitable helium concentrations in west-central and southern Alberta.
- Exploration and development of helium in the subsurface leverages the knowledge, expertise, and infrastructure available for oil and gas in Alberta.
- The proximity to the United States adds to Alberta's potential to fill in the supply issues caused by the depletion of U.S. helium resources.

9.4.6 One-Year Tariff Scenario (Tariff Case)

The implementation of tariffs on Canadian products is expected to reduce investments and development in Alberta's helium projects. Tariffs could lead to increased costs and reduced competitiveness for Alberta producers. Consequently, there would be an increased uncertainty in investment decisions in the coming years with producers deferring projects until the tariffs ease. Under the tariff case, helium production is expected to reach 9.8 10^3 m^3/d in 2034, 6.5% below the base case forecast.

Figure S9.5 shows the helium production base case and tariff case forecasts.

Figure S9.5 Alberta helium production (base case vs. tariff case)



9.4.7 Limitations or Risks to the Outlook

- Helium producers have fewer tax incentives than other mineral explorers to mitigate upfront exploration and production costs.
- Many economic areas for helium development are also suitable for carbon storage, limiting the availability of land leasing and mineral tenure rights for helium production.

Alberta’s helium industry's progress may be hindered if the current high demand diminishes. Alberta has the opportunity to develop a sustainable helium supply, ensuring reliable delivery across various sectors.

9.5 Lithium

9.5.1 What is Lithium

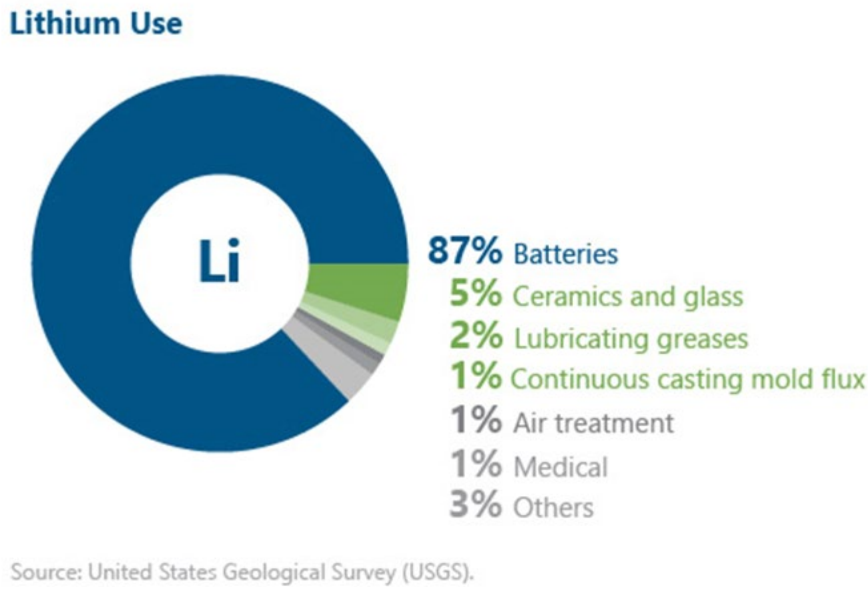
Lithium is considered the lightest of all metals and the lightest solid element under standard conditions. Lithium extraction and processing methods vary depending on the source material:

- lithium-bearing rocks (e.g., spodumene ore)
- clay
- seawater
- subsurface brines (i.e., geothermal, oil and gas field brines)
- recycled electronics

Globally, most lithium is produced by the precipitation of lithium-containing salts from shallow underground brine reservoirs or by rock-hosted mining. In Alberta, lithium is in deep-formation waters often associated with oil and gas reservoirs. Based on current geological knowledge, the areas with the most potential are Devonian-aged carbonate reservoirs in west-central and southern Alberta. The AGS is undertaking a program to expand the publicly available geoscience data for emerging resources, including lithium.

Companies and research groups in Alberta are testing DLE technology. This technology allows access to Alberta's lithium-brine potential found in existing oil and gas reservoirs, enabling the recovery of lithium concentrate, which is the first step in the value chain.

Batteries for electronics and electric vehicles drive global lithium demand, followed by ceramics and glass. The following figure shows the primary uses of lithium.



Demand for lithium is expected to increase as the demand for electric vehicles (EVs) powered by lithium-ion batteries is projected to grow. Consumers will likely purchase EVs to reduce fuel costs and take advantage of improved battery technology or for environmental reasons.

9.5.2 Federal and Provincial Critical Minerals Strategy

The federal government has included lithium on Canada's critical mineral list due to its role in economic security and transitioning to a low-carbon economy. Critical minerals are vital to growing Canada's clean, modern economy and are essential for clean technology applications, renewable energy, defence and security technologies, agriculture, and medical applications. In 2022, the federal government released Canada’s $3.8 billion, eight-year *Canadian Critical Minerals Strategy* to increase domestic extraction and production of lithium and other critical minerals. The federal government has invested in E3 Lithium to advance Canada’s EV battery production through the federal Strategic Innovation Fund Net Zero Accelerator initiative and the Critical Minerals Research, Development and Demonstration Program. Building sustainable infrastructure is also a key component of the *Canadian Critical Minerals Strategy*. The Government of Canada has been accepting applications under the Critical Minerals Infrastructure Fund (CMIF). The CMIF supports the development of infrastructure projects that will enable and grow the sustainable development of critical minerals.

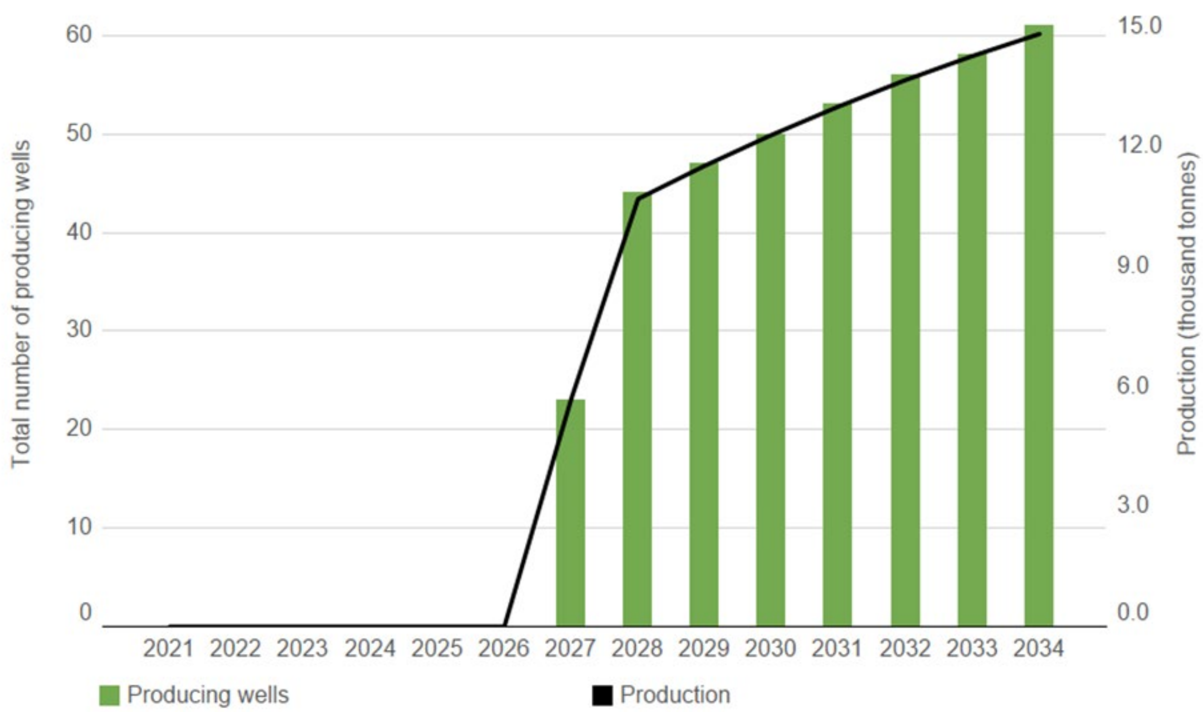
Alberta’s *Mineral Strategy and Action Plan* was released in November 2021 and aligns with the federal government’s strategy. The GoA has expanded the mandate of the AER to include mineral resource development. The Mineral Resource Development Act establishes the AER as the regulator of mineral resources. Alberta has extensive geological data and expertise to enable the development of Alberta's lithium resources to capitalize on increasing demand.

Lithium companies that invest in research and development in Alberta are eligible to apply for the Alberta Innovation Employment Grant, a refundable tax credit. Alberta Innovates is another financial incentive program that supports research and innovation by providing expertise, services, and funding to postsecondary researchers, entrepreneurs, and industry.

9.5.3 Production in 2024 and Base Case Forecast

Currently, there is no commercial lithium production in Alberta. However, E3 Lithium plans for commercial production of 5.7 thousand tonnes of lithium from 23 producing wells starting in 2027. The production and well forecasts involve weighing the risks based on the likelihood of the project meeting its commercial start date and production capacity. Total lithium production in Alberta is forecast to rise to 14.8 thousand tonnes by 2034 (see Figure S9.6).

Figure S9.6 Alberta lithium production and producing wells



Potential uses of lithium in Alberta include industrial applications, such as the chemical production of lithium carbonate and lithium hydroxide, mainly used in manufacturing lithium-ion batteries.

9.5.4 Projects

Several companies in Alberta have announced projects:

- In June 2024, E3 Lithium released a summary of key results from its pre-feasibility study for the Clearwater Project based on the DLE field pilot. In January 2025, they successfully produced battery-quality lithium carbonate from Leduc brines with demonstration-scale equipment in a laboratory. The lithium-brine demonstration facility will replicate the functionality of a small-scale commercial system and will be operational in 2025.
- NeoLithica will drill two brine wells in 2025 for comprehensive reservoir engineering evaluations. The wells will provide the brine needed to conduct a pre-commercial pilot for its Peace River project. The pilot facility is expected to be operational in 2025. NeoLithica will develop an aquifer management plan and commission a prefeasibility study once the pilot ends.
- LithiumBank's Boardwalk project DLE pilot brine-testing facility started in 2024 with brine sourced from four wells. The pilot will focus on testing their DLE technology, emphasizing concentrate quality, flow rate, and lithium recovery.

9.5.5 Alberta Resource Potential

Lithium brines have been recognized in Alberta's oil and gas reservoirs since the early 1990s,[12] when companies identified high lithium concentrations in brines of the Devonian Leduc and Swan Hills Formations. More recent studies[13] indicate that additional Devonian geological units, such as the Nisku and Wabamun, may also be viable targets for lithium extraction.

E3 Lithium operates two projects in the Bashaw district, Exshaw West and Central Clearwater between Calgary and Edmonton (see map below), oil brines of the Leduc Formation have concentrations around 75 milligrams per litre (mg/L) for an indicated and measured mineral resource estimate of 16 million tonnes of lithium carbonate equivalent (LCE).[14] The Swan Hills and Leduc Formations in west-central Alberta also have brines with economic lithium concentrations (i.e., a cutoff of 50 mg/L). According to LithiumBank,[15] the Boardwalk project has lithium resource estimates (i.e., measured, indicated, and inferred resources) of 5.7 million

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[12] Hitchon, B., Underschultz, J.R. and Bachu, S. (1993): Industrial mineral potential of Alberta formation waters; Alberta Research Council, Alberta Geological Survey, Open File Report 1993-15, 85 p.

[13] Reimert, C., Lyster, S., Palombi, D. and Bernal, N. (2025): Brine geochemical data, Mineral Mapping Program, 2023 (tabular data, tab delimited format); Alberta Energy Regulator / Alberta Geological Survey, AER/AGS Digital Data 2023-0019. Bernal N. (2025). The Origin of Lithium and Other Alkali Metals in Devonian Brines of Alberta. Open File Report (OFR), Alberta Energy Regulator / Alberta Geological Survey, (in preparation).

[14] E3 Lithium, 2023. 43-101 Technical Report: Lithium Resource Estimate. Bashaw District Project, Central Alberta. March 21, 2023.

[15] LithiumBank 2024a. NI 43-101 Technical Report & Preliminary Economic Assessment for the Boardwalk Project. February 24, 2024. LithiumBank, 2024b. Resources Corp. Park Place NI 43-101 Technical Report. June 24, 2024.

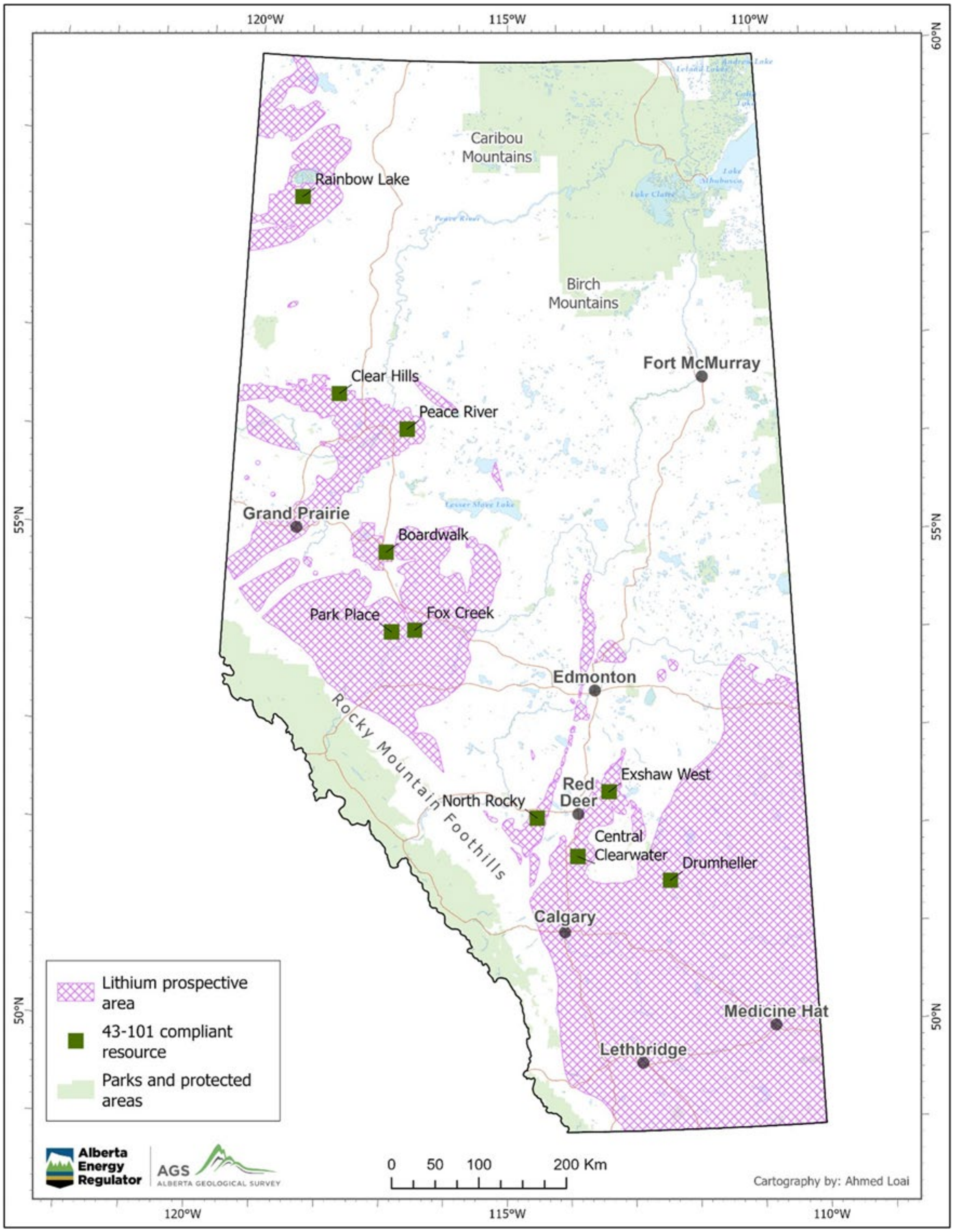
tonnes of LCE, and the Park Place project has 24.5 million tonnes of LCE. The projects have a lithium grade between 79 and 82 mg/L.

In northwestern Alberta, other Devonian formations, such as the Keg River and Slave Point and the Triassic Montney Formation, require more data for a proper assessment, but have lithium brines that may be viable with improvements in extraction technology. Currently, lithium concentrations as low as 50 mg/L have been the subject of extraction technologies.[16]

Alberta's lithium brines are unique because they are extracted through wells, eliminating the need for mining or extensive surface operations, unlike hard rock deposits or continental brines that require large evaporation ponds for concentration.

The map below shows brine-hosted lithium prospectivity in Alberta, including projects with resource estimates. Polygons for prospective areas are under final review and are expected to be published on the AGS website and will replace Map 590.

[16] S&P Global (2024). Direct lithium extraction from oil and gas production – An initial assessment. Nov. 2024. Https://www.spglobal.com/content/dam/spglobal/ci/en/documents/products/pdf/CI_1124_Lithiumfromproducedwater.pdf?utm_source=chatgpt.com



9.5.6 Limitations or Risks to the Outlook

Lithium extraction costs are expected to be lower in the future. Lithium production is expected to become competitive as new extraction methods are developed and proven scalable and processing infrastructure becomes available in the coming years. The economic feasibility of the lithium industry depends on climate change policies, technology development, financial support, and associated risks. Risks include disruptive technologies, concentrated supply chains, and potentially volatile markets. Several actions can be taken to improve lithium economics and reduce investment risks:

- Design advanced extractive technologies.
- Ensure responsible mining and environmental, social, and corporate governance standards to attract investors.
- Establish infrastructure and supply chains.

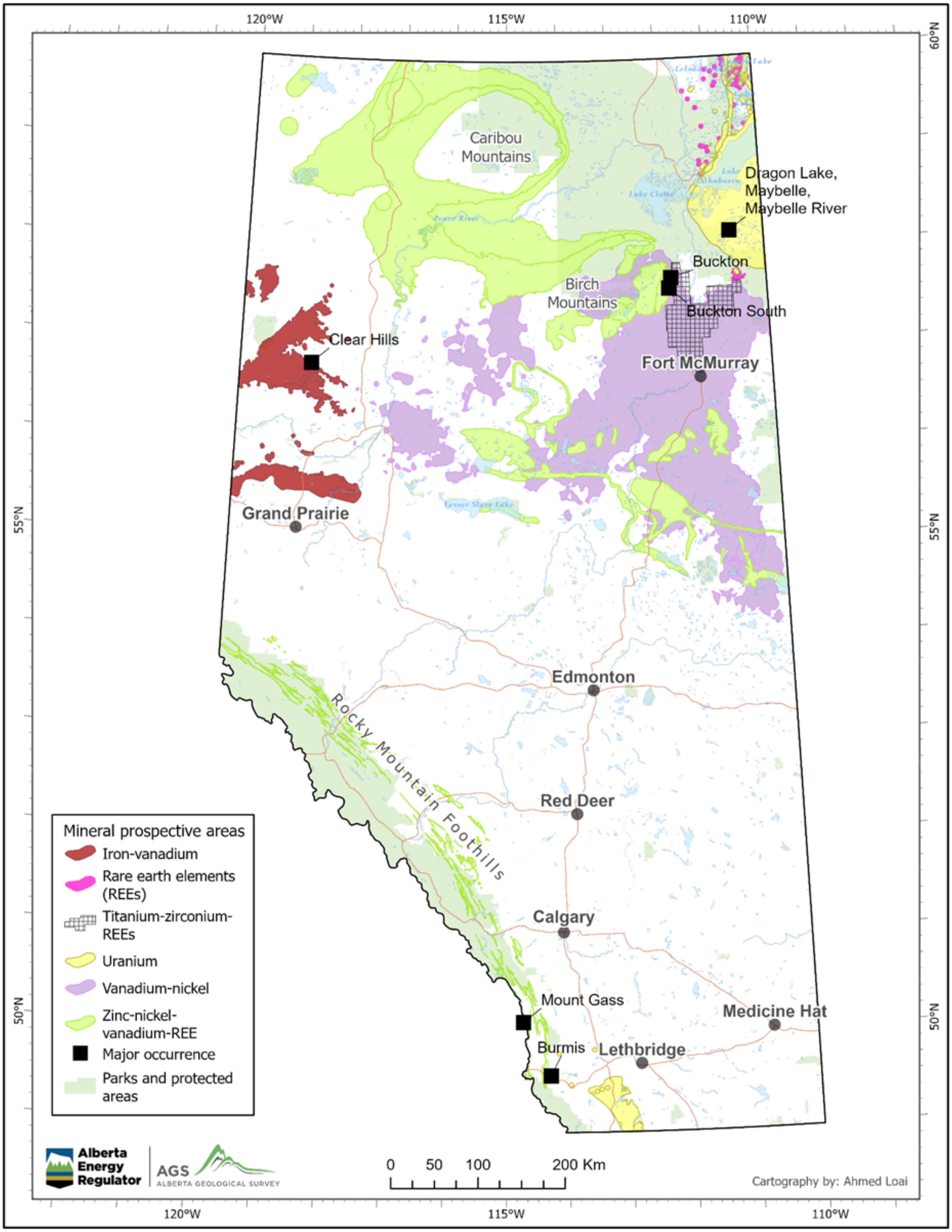
Since there is no commercial lithium production yet, there is no tariff case scenario forecast. The industry is still in the early stages of development, and tariffs are not anticipated to delay the start of commercial lithium production.

9.6 Other Critical Minerals

9.6.1 Introduction

Alberta has a wide variety of critical mineral occurrences and several deposits. While significant recent work has been done on evaluating brine-hosted lithium resources and assessing their economic potential, ten additional mineral commodities from Canada's critical minerals list are currently deemed to have moderate to high prospectivity in Alberta (INF 156). The following commodities are presented because of their near-term prospectivity: uranium, vanadium, rare-earth elements, iron, and zinc. Polygons for prospective areas are under final review and are expected to be published on the AGS website and will replace Map 590. The map below highlights major occurrences and zones of prospectivity.

The map below shows selected major occurrences and prospective areas of Alberta for uranium, vanadium, rare-earth elements, iron, and zinc. Additional mineral occurrences are available in the Alberta Interactive Minerals Map and mineral occurrence lists (DIG 2019-0026).



120°W
115°W
110°W
60°N
55°N
50°N
Caribou Mountains
Dragon Lake, Maybelle, Maybelle River
Buckton
Birch Mountains
Buckton South
Clear Hills
Fort McMurray
Grand Prairie
Edmonton
Rocky Mountain Foothills
Red Deer
Calgary
Mount Gass
Medicine Hat
Burmis
Lethbridge
Mineral prospective areas
Iron-vanadium
Rare earth elements (REEs)
Titanium-zirconium-REEs
Uranium
Vanadium-nickel
Zinc-nickel-vanadium-REE
Major occurrence
Parks and protected areas
Alberta Energy Regulator
AGS
ALBERTA GEOLOGICAL SURVEY
0 50 100 200 Km
Cartography by: Ahmed Loai

9.6.2 Uranium

Because of its energy density and fission properties, uranium is primarily used for nuclear power applications but has some additional military applications. Uranium occurs in three main deposit types in Alberta: unconformity-related uranium, sandstone-hosted uranium, and intrusion-hosted uranium. Like the world-class uranium deposits in Saskatchewan, Alberta hosts an unconformity-related uranium prospect in the Athabasca Basin of northeastern Alberta called the Dragon Lake/Maybelle River uranium project. In addition, low-grade sandstone-hosted uranium has been identified in southwestern Alberta. In northeastern Alberta, pegmatite and granitoid intrusions exhibit low- to moderate-grade uranium associated with rare-earth elements.

The AGS has published reports investigating the potential of unconformity-related uranium in northeastern Alberta (OFR 2009-19), sandstone-hosted uranium in southern Alberta (e.g., ESR 2007-10), and intrusion-hosted uranium in the northeast (OFR 2010-08). Additional investigation and preparation of a uranium commodity summary are ongoing at the AGS.

9.6.3 Vanadium

Vanadium is used primarily in steel alloys, though emerging technologies such as vanadium redox batteries have been increasingly studied for long-term energy storage. The most promising vanadium sources in Alberta are oil sands waste, the Rambling Creek/Clear Hills ironstone deposit, and the Birch Mountains metal-rich black shale deposit (INF 155). Recent estimates, based on 2017 production values, suggest that between 34 000 and 39 000 tonnes of vanadium are concentrated through oil sands and in situ bitumen processing each year in Alberta (SPE 113). The AGS is currently collecting and compiling data on oil sands and their associated wastes to enhance public understanding of the distribution of vanadium and other critical elements in these geological and industrial waste materials.

9.6.4 Rare-Earth Elements

Rare-earth elements are a group of elements that have a wide range of uses, including catalysts, ceramics, phosphors, strong magnets, alloys, and lasers. In Alberta, elevated concentrations of rare-earth elements have been identified in the Birch Mountains metal-rich black shales, pegmatites and granitoids of the Canadian Shield, sedimentary phosphate-bearing rocks of southwestern Alberta, oil sands froth treatment tailings, and coal fly ash. The AGS continues to investigate these rare-earth sources.

9.6.5 Iron

Iron is used primarily in steel production and represents one of the most important industrial commodities. Globally, iron is produced primarily from banded iron formations and mafic intrusive complexes. In Alberta, various iron occurrences have been identified, including the Rambling Creek/Clear Hills iron deposit in west-central Alberta (e.g., GEO 05-0205, OFR 2009-01) and the Burmis paleoplacer magnetite occurrences in southwestern Alberta (BUL-009).

9.6.6 Zinc

Zinc is used primarily as a galvanizing agent and in brass alloys due to its reactive properties. In Alberta, zinc has been identified in the Birch Mountains metal-rich black shale deposit and in numerous metal-rich black shales throughout Alberta (SPE 009, Eccles et al. 2013). Significant zinc concentrations have been recorded in the Oldman occurrence at Mount Gass in southwestern Alberta. The AGS has published several reports on these metal-rich black shales (SPE 009) and on the Oldman occurrence (OFR 1973-25 and OFR 1985-08).

9.7 Emerging Resources Methodology

9.7.1 Production Forecast

The methodology for each commodity supply forecast

- included production from new and existing projects,
- considered all approved and applied-for projects, and
- assigned risk factors based on the project status.

The projects considered in the commodity supply forecasts were assessed for the likelihood of meeting the commercial start-up date and stated production capacity. Some projects, although considered, were not included in the ten-year forecast due to the high uncertainty about their likelihood of becoming operational within the next decade.

Forecast considerations and factors affecting each specific commodity are described below.

9.7.1.1 Hydrogen

Time series modelling was used to determine the future pace of production expansion. All existing projects were assumed to continue producing at normal production levels over the forecast period.

The forecasts for hydrogen considered factors that may affect the pace of development, such as complementary policies and de-risking projects through government partnerships.

9.7.1.2 Geothermal

Time series modelling was used to determine the future pace of production expansion.

The forecasts for geothermal resources considered factors that may affect the pace of development.

9.7.1.3 Helium

In projecting helium production, we combined expected production from active wells with new wells placed on production. The number of new wells placed on production is determined by the regression of commodity price, average initial productivity, and decline rates. Production volumes are estimated based on the new wells projection.

9.7.1.4 Lithium

Time series modelling was used to determine the future pace of production and the number of new wells placed on production. The lithium forecasts considered factors that may affect the pace of development, such as the number of new wells placed on production and technology development.

9.7.2 Data

9.7.2.1 Hydrogen and Lithium Data

Hydrogen and lithium data are based on AER research and publicly available data.

9.7.2.2 Helium Data

Historical data are as reported by industry in Petrinex until the end of December. It does not include any subsequent amendments.

9.7.2.3 Geothermal Data

Historical geothermal production was calculated using Alberta Electric System Operator hourly electricity generation data.

10 Carbon Capture, Utilization, and Storage

10.1 What Are CCUS and CCS

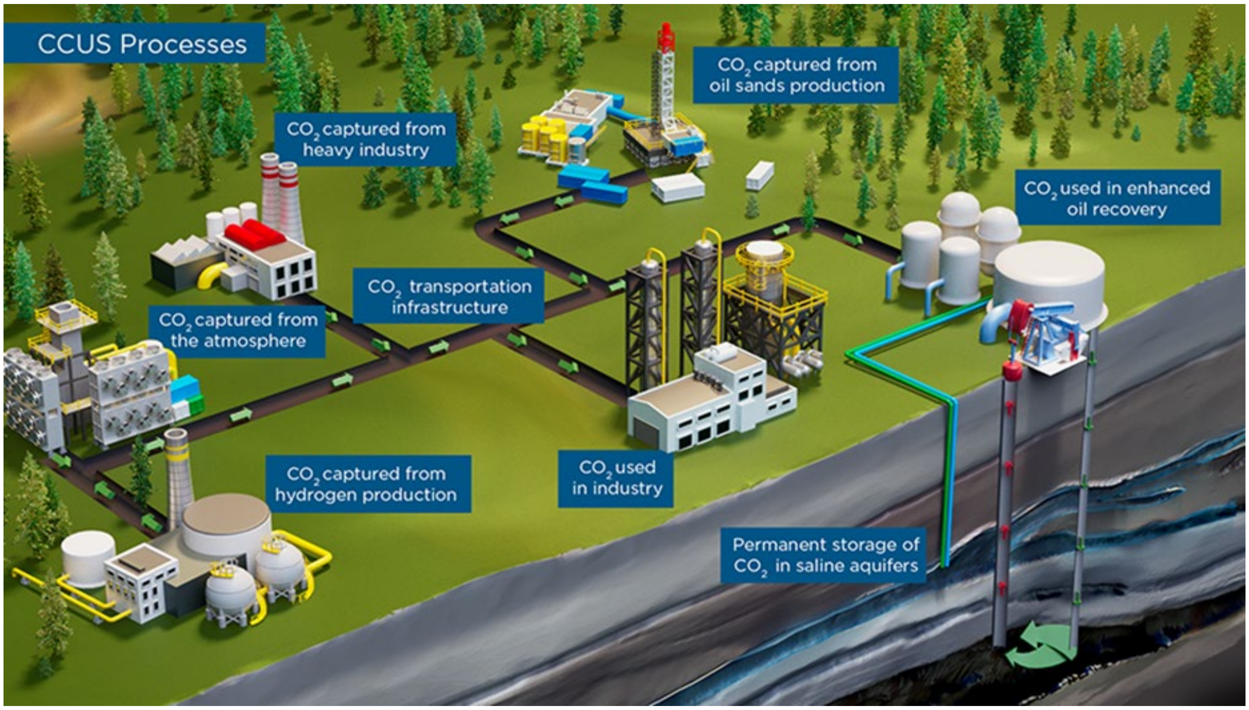
Carbon capture, utilization, and storage (CCUS) refers to a range of technologies and processes that capture carbon dioxide (CO_2) from industrial sources or directly from the atmosphere. The captured CO_2 can then be injected into underground porous formations and used in CO_2-enhanced oil recovery (CO_2-EOR) or the production of manufactured goods. CO_2-EOR improves the production of residual oil and results in some CO_2 becoming permanently stored (i.e., sequestered) within the formation. In addition, CO_2 can be used in commercial processes, permanently trapping the CO_2 in higher-value products.

Carbon capture and storage (CCS) is similar to CCUS but excludes the utilization of CO_2. Instead, captured CO_2 is injected into subsurface formations, such as saline aquifers or depleted oil and gas reservoirs, for permanent storage.

Both CCUS and CCS technologies seek to reduce the amount of CO_2 released into the atmosphere. Throughout the remainder of this chapter, CCUS will refer to both technologies unless specified otherwise.

The CCUS process (see diagram below) begins with capturing CO_2, which can occur at the industrial emission source (e.g., power generation, hydrogen manufacturing, oil sands mine, etc.) or directly from the atmosphere using direct-air capture technology. The captured CO_2 is then compressed and transported by pipeline or truck to its destination. The CO_2 is either stored permanently underground (e.g., in saline formations) or used and stored by CO_2-EOR. The Alberta Energy Regulator (AER) has regulated CO_2-EOR projects since the 1980s.

Captured CO_2 may also be used as feedstock for higher-valued products. Some non-oil industry applications include using CO_2 in food and beverage production, metal fabrication, cooling, fire suppression, and plant growth stimulation in greenhouses. Additionally, some experimental and pilot applications are under development, such as cement production, carbon nanotubes, and CO_2-to-liquid fuels.



10.2 Regulatory Framework for CCUS

Alberta is among the leading jurisdictions in CCUS policy and deployment of a regulatory framework. CCUS projects are covered by Alberta's existing oil and gas legislation: *Oil and Gas Conservation Act*, *Mines and Minerals Act*, *Surface Rights Act*, *Public Lands Act*, *Environmental Protection and Enhancement Act*, and *Water Act*. Surface rights for CCUS projects are managed the same as oil and gas developments in the province. Pore space rights for CO_2 are covered by the *Mines and Minerals Act*. Roles and responsibilities for Alberta's CCUS regulatory framework are divided between Alberta Energy and Minerals, Alberta Environment and Protected Areas, and the AER.

Alberta Energy and Minerals roles include

- development of policy and regulatory frameworks,
- issuance of tenure rights for evaluation and sequestration of CO_2, and
- management of the Post-Closure Stewardship Fund.

Alberta Environment and Protected Areas responsibilities include

- implementation of the *Emissions Reduction and Energy Development Plan*,
- management of the *TIER* regulatory system that promotes CCUS through the generation of carbon credits, and
- regulating CO_2 capture facilities not connected to, or associated with, energy resource activity (e.g., chemical manufacturing plant).

As it pertains to CO_2, the AER regulates

- the energy-related facilities[17] that capture CO_2,
- the pipelines that transport the CO_2 within Alberta,
- the subsurface injection activities, which include permanent sequestration and CO_2-EOR projects, and
- oversight of measurement, monitoring, and verification plans and closure plans.

Some key AER directives that provide technical requirements for CCUS projects include:

- *Directive 056: Energy Development Applications and Schedules*, which includes requirements for applying to construct or operate wells that inject CO_2, pipelines that transport CO_2, and facilities that capture CO_2.
- *Directive 065: Resources Applications for Oil and Gas Reservoirs*, which details the approval process for subsurface injection, including measurement, monitoring, and verification plans for CO_2 sequestration, which are essential for containment assurance.

10.3 Carbon Dioxide Sequestration in 2024

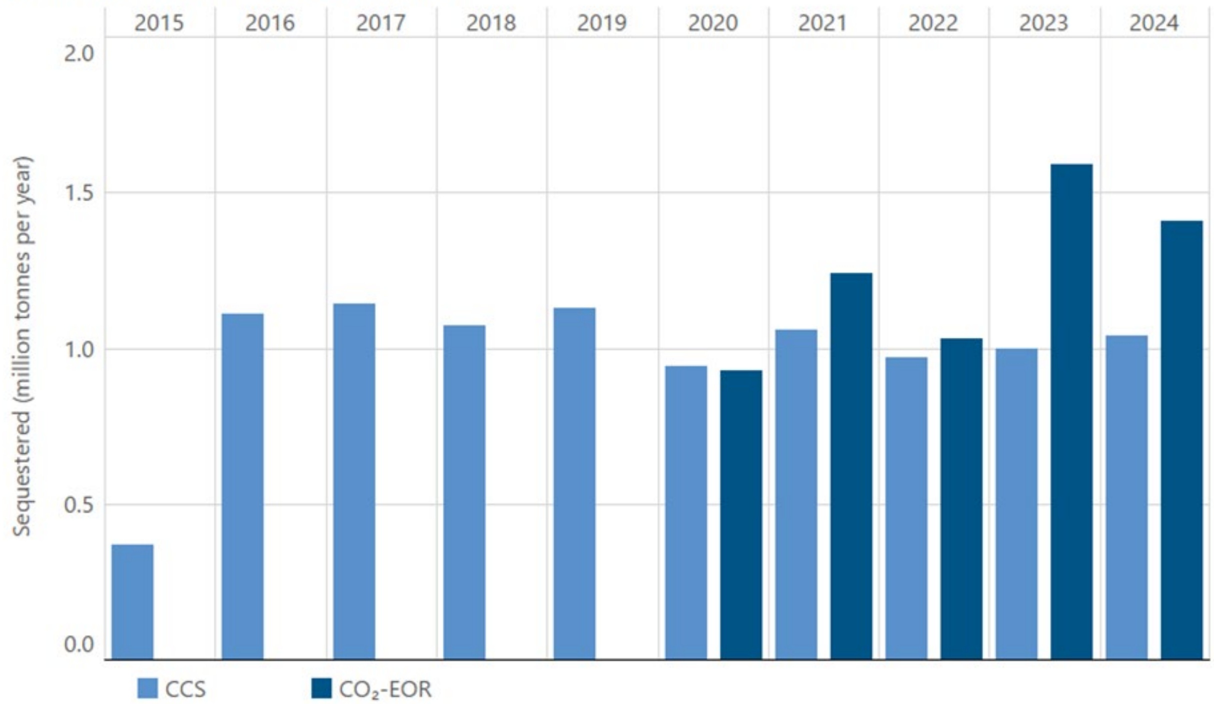
In 2024, 1.0 million tonnes of CO_2 were permanently sequestered by CCS (Figure S10.1), a level similar to the previous year. CCS injection facilities have permanently sequestered a cumulative total of 9.8 million tonnes of CO_2 since 2015.

There were 1.4 million tonnes of CO_2 were permanently sequestered by CO_2-EOR in 2024 (Figure S10.1), a slight decrease from the previous year due to lower production rates from associated carbon-emitting facilities. Since 2020, CO_2-EOR facilities have permanently sequestered 6.2 million tonnes of CO_2.

Currently, the data for sequestration by CCS includes the Shell Quest CCS project, and sequestration by CO_2-EOR includes Enhance Energy's Clive Field CO_2-EOR project. Sequestration values do not include CO_2 permanently sequestered through acid gas disposal and other CO_2-EOR projects. Additionally, since there is no CCUS sequestration forecast, a one-year tariff scenario is not included in this chapter.

[17] Energy infrastructure includes intraprovincial pipelines, wells, geothermal facilities (heat or power), gas or oil processing plants and facilities, in situ bitumen projects, bitumen upgraders, oil sands mines, and coal mines. It does not include interprovincial or international pipelines, oil refineries, and electricity generation plants (except geothermal).

Figure S10.1 Alberta CO2 sequestration



Historical values are sourced from Petrinex. Values do not include CO_2 sequestered via acid gas disposal and CO_2-EOR projects that sequester less than 100,000 tonnes per year.

10.4 Existing Projects

There are two large-scale CCUS projects in Alberta: Shell Quest and the Alberta Carbon Trunk Line (ACTL). Quest involves capturing CO_2 from the hydrogen plant at the Scotford Upgrader and transporting it by pipeline to the injection site for sequestration in an underground saline formation (Basal Cambrian Sandstone unit). The ACTL relies on CO_2 captured from hydrogen production at the Sturgeon Refinery and the Redwater Fertilizer Plant. The captured CO_2 is used in the Clive Field at Enhance Energy's CO_2-EOR project.

10.5 Methodology

Historical data were reported by the industry until the end of December and does not capture any subsequent amendments. The average density of the injected fluid, provided in the project annual reports, is used to convert the reported volumes to the mass equivalent. The CCS sequestration volumes of CO_2 are sourced from Petrinex. The CO_2-EOR injection volumes reported in Petrinex for the fluid injectors of the scheme are gross volumes, which include CO_2 volumes supplied from capture sites and CO_2 volumes that are recirculated through the active oil and gas producing wells in the pool (also recorded in Petrinex). The sequestered volume is then calculated by subtracting the recirculated CO_2 volume from the gross injection volume.

Appendix 1 Glossary

A

Alberta Activity Index (AAX)

This index, developed by the Alberta Treasury Board, closely tracks economic activity. It is a weighted average of the following nine monthly indicators: employment, average weekly earnings, retail trade, wholesale trade, manufacturing, new truck sales, housing starts, rigs drilling, and oil production.

Alberta Energy Company's storage hub (AECO-C)

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

AECO-C price

The Natural Gas Exchange volume-weighted average of transacted prices for all physically delivered natural gas in a calendar month; at the Alberta Nova Inventory Transfer (ABNIT) market centre.

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.

apportionment

When shippers desire to ship more oil or oil products in a given month than the pipeline can transport, shipper volumes are apportioned (reduced) based on the tariff in effect. Apportionment can be caused by factors such as growing supply, increased demand, pipeline reconfigurations, reduced pipeline capacity, or refinery maintenance.

B

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. and are considered a global benchmark for oil prices.

breccia

Rock composed of broken fragments of mineral or rock cemented together by a finer-grained matrix. In the case of the McMurray Formation, mudstone breccias consist of large angular mud fragments within sands.

brownfield

Brownfield projects are projects built where land has previously been developed or where there is room to expand an existing facility.

burner-tip

The location where a fuel is used by a consumer.

butane

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)).

C

capital costs

Expenditures by a company to build, purchase, or upgrade physical assets such as land, equipment, and processing facilities.

carbon capture, utilization, and storage (CCUS)

A range of technologies and processes that capture carbon dioxide from industrial sources or directly from the atmosphere, which is then used by injecting it into underground porous formations as part of CO_2-enhanced oil recovery or used to produce manufactured goods.

carbon capture and storage (CCS)

A process similar to CCUS but excludes the utilization of carbon dioxide and instead it is injected into subsurface formations (e.g., saline aquifers or depleted oil and gas reservoirs) for permanent storage.

clean coal

Clean coal is coal that has been processed for export by washing raw coal to remove soil and rock sediment. While subbituminous coal is burned without any form of upgrading, both metallurgical and thermal bituminous coal are sent in raw form to a preparation plant to be processed into clean coal. On average, about 65% of raw metallurgical bituminous coal and less than 50% 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.

coal

A combustible sedimentary rock that contains at least 50% 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 one-third 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.

conventional resources

Conventional resources are those that have the necessary rock permeability and fluid viscosity to be commercially productive without the use of stimulation technology. These resources are buoyancy-driven deposits that accumulate in structural or stratigraphic traps.

commingled

Commingled flow describes the production of fluid from two or more separate zones through a single conduit.

compressibility factor

A correction factor for nonideal 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

- 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
- is recovered from an in situ coal scheme and is liquid at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, section 1(1)(k)).

crude bitumen

A naturally occurring viscous mixture of mainly 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 greater than or equal to 900 kg/m^3 and less than 925 kg/m^3.

crude oil (light)

Crude oil with a density of 850 kg/m^3 or less.

crude oil (light-medium)

Crude oil with a density less than 900 kg/m^3.

crude oil (medium)

Crude oil with a density equal to 850 kg/m^3 and less than 900 kg/m^3.

crude oil (ultra-heavy)

Crude oil with a density of 925 kg/m^3 or greater.

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.

cyclic steam stimulation (CSS)

A technique that produces bitumen by injecting steam into underground oil sands reservoirs (i.e., wells) to heat bitumen, separate it from the sand, and allow it to flow to the well and be produced.

D

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.

debottleneck

An engineering optimization process conducted by a company to improve efficiencies, reduce constraints limiting output at a facility, or both.

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.

developed reserves

Developed reserves are reserves that are expected to be recovered from existing wells and installed facilities. If facilities have not been installed, developed reserves are reserves that are expected to be recovered from existing wells where the cost required to put the reserves on production is relatively minor compared with the cost of drilling and completing a new well. There are two categories of developed reserves: producing and non-producing.

developed reserves (non-producing)

Developed non-producing reserves are reserves that either (1) have not been on production or (2) have previously been on production but are no longer being produced because the well is shut in and the date for when production is to resume is unknown.

developed reserves (producing)

Developed producing reserves are reserves that are expected to be recovered from completion intervals open at the time the reserves estimate was generated. These reserves may be currently producing or, if shut in, they must have previously been on production and the date for when production is to resume must be known with reasonable certainty.

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.

drainage areas (SAGD)

Area surrounding a well pair or multiple well pairs from which bitumen is produced.

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.

E

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/development

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

- aiding in the lifting of fluids in the well, or
- 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 and independent of current commodity prices.

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).

F

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.

formation

A rock unit with comparable lithology, facies, or other similar properties that allows geologists to map, describe, and name it. The primary unit of lithostratigraphy. Two or more formations can be packaged together into a group and formations can be subdivided into members.

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.

G

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 (liquefied petroleum gas)

Mixes containing butanes and propane are referred to as liquefied petroleum gas (LPG) and are used primarily as fuel sources for cooking and heating appliances and for vehicles.

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 (sour)

Natural gas that contains measurable amounts of hydrogen sulphide (H_2S). For this report, measurable refers to volumes of H_2S in excess of 0.01%.

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

- not governed by a base allowable, but
- 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 expenses associated with regulation or production restrictions where this serves little or no purpose.

greenfield

Greenfield projects are projects built on land that has not previously been used and has no existing components or structures.

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.

H

halo play

A halo play is an extension of a conventional reservoir that does not meet the traditional cutoffs for conventional reservoirs. In halo plays, the source rock is not the reservoir. The permeability of a halo play is often less than, but can exceed, 0.1 millidarcy (mD). The permeability of a halo play is generally higher than the permeability in tight or shale plays. In order to produce the resources within a halo play, more advanced completion techniques are needed, such as horizontal multistage fracturing.

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.

hydraulic fracturing

Hydraulic fracturing involves pumping fluid into a wellbore to create enough pressure to crack, or fracture, the rock layer. The fluid usually contains a "proppant," like sand, that helps keep the fractures open, allowing oil and gas to be produced from the well.

hydraulic multistage fracturing

The application of hydraulic fracturing over multiple segments within a well leg, starting at the "toe," or near-end point of the drilling leg, and moving backwards to the "heel," or vertical portion of the well leg. This drilling and completion technique is commonly used to access low-permeability reservoirs. It significantly improves production because the wellbore is able to access a greater length of the reservoir.

I

inclined heterolithic stratification (IHS)

IHS deposits consist of dipping interbedded sands and muds. IHS constitute a significant portion of the McMurray Formation.

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.

L

limestone

A carbonate sedimentary rock predominantly composed of calcite of organic, chemical, or detrital origin. Minor amounts of dolomite, chert, and clay are common in limestones.

liquefied natural gas (LNG)

Natural gas that has been converted to liquid form at deep freezing temperatures for storage and overseas transportation.

M

marketable bitumen

Upgraded and nonupgraded bitumen available to be used as refinery feedstock.

maximum day rate

The operating day rate for gas wells when they are first placed on production. Estimating 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.

N

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 (NGLs) from marketable gas. Most plants are deep-cut facilities that then ship an NGL stream to fractionation plants in central Alberta.

nonroutine venting

Nonroutine venting can be planned or unplanned, such as in the case of an emergency or when equipment in a facility is depressurized.

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.

O

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 areas

For administrative purposes, the geological formations and the geographic areas in Alberta that contain bitumen are designated as oil sands areas. There are three oil sands areas in Alberta: Athabasca, Cold Lake, and Peace River.

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.

overnight rate

The overnight rate is the interest rate at which major financial institutions borrow and lend one-day (or "overnight") funds among themselves; the Bank of Canada sets a target for that rate. This target for the overnight rate is often referred to as the bank's key interest rate or key policy rate.

P

parasequences

A volume of genetically related rock containing no extensive period of erosion or non-deposition, bounded by flooding surfaces. These surfaces are sharp contacts between rocks denoting a water deepening event.

pay (net)

The thickness of rock that contributes to economically viable production. Unproductive or uneconomic layers are not included in the net pay thickness.

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)).

permeability

Permeability is defined as the ability, or measurement of a rock's ability, to transmit fluids. Typically measured in units or subunits of darcies.

play

A geological play can be defined as a set of known or estimated oil or gas accumulations (pools and deposits) within a petroleum system that share similar geological, geographic, and temporal properties, such as a source rock, migration pathways, timing, trapping mechanism, and hydrocarbon type.

pool

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, 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 (effective)

Effective porosity is defined as the volume of the interconnected pores that contribute to fluid flow in a reservoir. The effective porosity of a reservoir is calculated by subtracting the fluids bound on clays and shales and within isolated pores from the total porosity. Therefore, effective porosity is less than or equal to total porosity.

porosity (total)

Total porosity is defined as being either the percentage of pore volume or void space or the volume within a reservoir that can contain fluids. The total porosity does not necessarily contribute to fluid flow in a reservoir.

pressure (initial)

The reservoir pressure at the reference elevation of a pool upon discovery.

probable reserves

Probable reserves are additional reserves with a lower certainty of recovery than proved reserves.

proved reserves

Proved reserves are reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

proved plus probable reserves

Proved plus probable reserves is the sum of proved and probable reserves categories. The sum is the best possible estimate for the volume of reserves.

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)).

R

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.

refinery utilization

Refinery utilization shows the ratio of throughput to capacity.

remaining established reserves

Initial established reserves less cumulative production.

removals

Product that has been removed from Alberta.

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 on major natural gas transmission lines.

reserves

Estimates of remaining quantities of petroleum anticipated to be recoverable from known accumulations as of a given date, using technology that is known, either currently available or in use, and commercially possible.

reservoir

Reservoirs are any subsurface rocks that are able to store fluids (water, oil, and gas) inside their pores or fractures.

resources

Quantities of petroleum estimated to exist originally in naturally occurring accumulations, including all known and estimated quantities yet-to-be discovered.

routine venting

Routine venting happens on a regular basis as part of normal operations. It can include venting from production casing vents, waste vents, and tanks.

S

sales gas

A volume of gas sold over a period of time. 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.

sequestration

The act or activity of injecting a fluid (such as carbon dioxide) into a subsurface porous formation and permanently trapping the fluid.

shale

The AER uses the criteria published in *Bulletin 2010-28: Zones Eligible for Shale Gas Fluid Codes*. As a general guide, a mudstone-shale succession may be defined as being one or more of the following:

- a laminated rock with greater than 67% clay-sized minerals, often with fissility
- a blocky or massive fine-grained sedimentary rock in which the proportion of clay is approximately equal to or greater than silt-sized particles
- a fine-grained, low-permeability clastic, carbonate, or mixed-lithology rock of which the exact composition is unknown; however, on a geophysical log, the response of the production interval is uniformly shaley

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.

source rock

A source rock is a rock rich in organic matter which, if heated sufficiently, will generate oil or gas. Due to advancements in technology, source rocks may also be targeted as reservoir rocks through the use of horizontal drilling and hydraulic multistage fracturing.

specification product

A crude oil or refined petroleum product with defined properties.

Station 2

Station 2 is the trading point at the physical intersection of many of the gas outputs from northern B.C. gas wells and processing plants.

steam-assisted gravity drainage (SAGD)

A method of in situ recovery where steam is injected into a horizontal well to heat the bitumen in a reservoir and allow it to flow; gravity pulls the heated bitumen to a second horizontal well positioned below the first and the bitumen is then produced to the surface.

steam-assisted gravity drainage (SAGD) well pad

A well pad made up of multiple pairs of wells, each pair has one well for high-pressure steam injection (injector), and one for the production of oil (producer).

sterilization

The rendering of otherwise definable economic ore as unrecoverable.

stochastic

Refers to the presence of a random variable. Stochastic modelling involves calculating probability distributions through random variation in inputs.

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.

sulphur

Sulphur is a chemical element commonly found in conventional natural gas, crude bitumen, crude oil, and coal.

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).

T

takeaway capacity

Takeaway capacity is the total capacity for moving crude oil out of Alberta, via pipeline, rail, and truck.

temperature

The initial reservoir temperature upon discovery at the reference elevation of a pool.

tight gas

Tight gas is gas trapped in the pores and fractures of low-permeability rocks. Producing tight gas requires extra stimulation, such as hydraulic fracturing.

tight hybrids

Tight hybrids are low-permeability oil or gas resources. They cannot be easily divided into "conventional" and "unconventional" resources by factors such as viscosity, degree of permeability, or recovery process.

This definition applies to "halo" deposits where the quality of the reservoir decreases with increasing distance from the conventional core and to mixed-lithology reservoirs containing both conventional and unconventional deposits.

tight oil

Tight oil is crude oil trapped in the pores and fractures of low-permeability rocks and is generally liquid under reservoir conditions. Producing tight oil requires extra stimulation, such as hydraulic fracturing.

U

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.

undeveloped reserves

Undeveloped reserves are reserves expected to be recovered from known accumulations where the cost required to begin production from an existing well is significant compared with the cost of drilling and completing an entirely new well. The costs required to begin production could include recompleting an existing well or installing production or transportation facilities. The reserves expected to be recovered must fully meet the requirements of the category indicating its probability of recovery (proved, probable, possible) and expected to be developed within a limited time.

In multiwell pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped subclasses or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that are expected to be recovered from specific wells, facilities, and completion intervals in the pool and their respective development and production status.

unit train

Unit trains, or block trains, are freight trains in which all cars are carrying the same type of commodity, all bound for the same destination. In this way, unit cars do not need to stop at different junctions for each commodity and can make single, nonstop runs.

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.

W

well

A hole drilled in the Earth for the purpose of finding or producing natural gas or crude oil.

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.

working gas storage

The amount of natural gas that can be injected into the storage and withdrawn at a later moment in time to meet demand.

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.

Z

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)).

zone (gross)

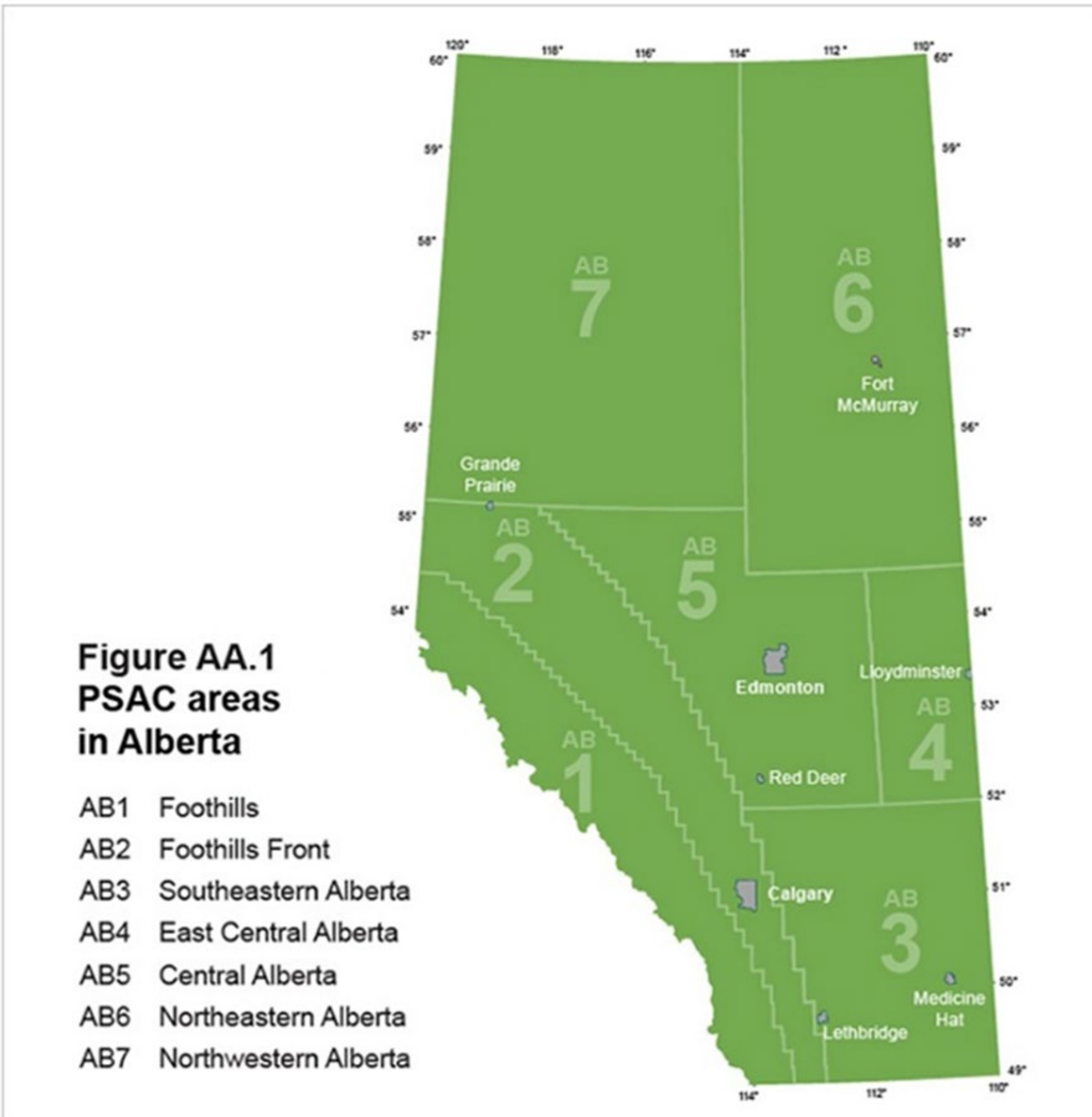
The full interval of rock from top to base of a zone. Gross zone will include uneconomic intervals.

zone (thief)

Water or gas zones within a steam-assisted gravity draining reservoir that steals heat or pressure from the steam injected into the reservoir. The more energy thief zones steal, the less there is remaining to heat the bitumen.

Appendix 2 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.



Appendix 3 Symbols and Conversion Factors

Table AA.1 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		

Table AA.2 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 gigajoule	= 0.9482133 million British thermal units (MMBtu) (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.

Table AA.3 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}

Table AA.4 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
Electricity (per megawatt-hour of output)	3.6

[a] Based on the heating value at 1000 Btu/cf.