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Methodology

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All the tables referenced in this methodology section are available as XLSX files under Section Data on the ST98 main page.

1 Prices and Capital Expenditure Methodology

Energy prices play a key role in energy development and reserves assessments. Prices are determined by supply and demand factors, which are influenced by economic activity, seasonal temperatures, market access, and nonmarket factors. All prices and exchange rate forecasts are compared with publicly available forecasts from major banks, consultants, and international forecasting agencies.

The crude oil, natural gas, and exchange rate forecasts were compared with publicly available forecasts from 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, the International Monetary Fund, and International Energy Agency.

All prices are in nominal dollars (i.e., not adjusted for inflation).

Crude Oil Prices

West Texas Intermediate

North American crude oil prices are reported as the front-month contract price of West Texas Intermediate (WTI) crude oil at Cushing, Oklahoma, which is the underlying physical commodity market for the New York Mercantile Exchange (NYMEX) with respect to 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 and compared with publicly available forecasts from the above-mentioned sources. 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 a sulphur content of less than 0.5%.

Western Canadian Select

The Western Canadian Select (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 of pipeline capacity from Hardisty, Alberta, to Cushing, Oklahoma, the U.S.–Canadian dollar exchange rate, and oil quality differences (e.g., sulphur content, density). Prices

are also 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.

Natural Gas Prices

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 natural gas futures prices for 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, the export capacity of North American liquefied natural gas terminals, and the above-mentioned publicly available sources. 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.

AECO-C

The AECO-C price from the Natural Gas Exchange (NGX) is the Alberta reference price. The 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.

Price Cases

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

U.S. and Canadian Exchange Rate Forecast

Physical commodities are traded internationally, and prices are influenced by the currency exchange rate in effect 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 Canadian commodity prices. The exchange rate assumptions are based on an evaluation of Canadian and U.S. economic indicators, including gross domestic product, monetary policy and inflation rates, residential and commercial investment, international trade flows, and oil price forecasts.

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 total oil and gas capital expenditures.

Historical statistics are from the Canadian Association of Petroleum Producers, with the 2025 values being estimates until companies report actual capital expenditures.

Capital expenditures are in nominal dollars.

Oil and Natural Gas

The oil and natural gas capital expenditure forecast represents capital spending on 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.

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.

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.

2 Crude Bitumen Methodology

Production Forecast

Mined Bitumen

Production from existing facilities and supply from future projects are considered in Table S3.5. 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 planned on-stream date and stated production capacity. This evaluation involves weighing the risks for each project. Some projects considered will ultimately not be included in the ten-year forecast because of the high level of uncertainty regarding whether they will come on stream within the next decade.

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 S3.6). 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 planned on-stream date and stated production capacity. This evaluation involves weighing the risks for each project. Some projects considered will ultimately not be included in the ten-year forecast because of the high level of uncertainty regarding 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 production from new wells. The number of new wells placed on production, along with their average initial productivity and decline rates, are the main determining factors in projecting production volumes. Similar to the crude oil well methodology, an economic model is used to determine the number of primary wells placed on production, forming 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.

Upgraded Bitumen

Table S3.7 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 also assessed, including long-term crude oil price forecasts, the price differential between light crude oil and bitumen, the time required to construct an upgrader, and the market penetration of new upgraded volumes—all of which affect project timing.

Crude Bitumen Production Forecast Accuracy

The crude bitumen production forecast over the past five years has shown reasonably good accuracy. The forecast deviation from the 2025 actual crude bitumen production ranged from 0% to 2%. The high level of accuracy resulted from improvements in our models and assumptions, allowing for a more precise alignment with actual outcomes.

Demand Forecast

The bitumen demand forecast primarily considers upgrading and refining capacity. Marketable production that exceeds 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.

Supply Costs

The supply cost (break-even price) of a resource project is the minimum constant dollar price required to recover all capital expenditures, operating costs, royalties, and taxes, while also earning 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 viable.

Assumptions

Reference projects in our supply cost estimates include in situ steam-assisted gravity drainage (SAGD) and standalone mining with cogeneration. Although each project is unique in its location and 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, while the upper range represents capital costs for greenfield projects.

A major component of operating costs is natural gas purchased for fuel and feedstock. For 2026 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 comply with the *Technology Innovation and Emissions Reduction Regulation* (*TIER*) to meet facility emission benchmarks. Facilities that do not directly meet their benchmark can comply by submitting offsets, performance and investment credits, or paying into the *TIER* fund.

Data

All 2025 data are as reported by industry through the end of December and do not reflect any subsequent amendments. We used crude bitumen production volumes submitted in Petrinex.

3 Crude Oil Methodology

Production Forecast

The AER forecasts for production and well activity are available by Petroleum Services Association of Canada (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, the Clearwater Formation, and the Viking Formation. 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)

Forecasting Crude Oil Production

The following variables are incorporated in the crude oil production forecast (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
- 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 also considers limiting factors such as current and future capital market conditions and remaining reserves.

Security Classification: Public

Initial Productivity Rates

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

Decline Rates

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

Crude Oil Production Forecast Accuracy

The crude oil production forecast deviation has narrowed significantly over the past five years, ranging from 21% in the 2021 report to only 1% in the 2025 report. The high deviation of the 2021 forecast largely reflects uncertainty surrounding global economic recovery following COVID-19 pandemic. The 2025 forecast reflects improvements made to our models and assumptions over time, allowing for more precise alignment with actual outcomes.

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 defined as the difference between Alberta production and Alberta demand.

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

Supply Cost (Break-Even Price)

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

- 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

Security Classification: Public

- taxes
- a 10% nominal rate of return

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

The AER defines a supply cost as the minimum constant dollar price required to recover all capital costs, operating costs, royalties, and taxes, while also earning a specified return on investment. The supply cost calculation determines a dollar value required to cover all costs 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.

Data

All 2025 data are as reported by industry through the end of December and does not reflect any subsequent amendments. The AER uses crude oil production volumes submitted to Petrinex by producers.

4 Natural Gas Methodology

Marketable Natural Gas

Marketable gas is natural gas that remains after raw gas is processed (to remove nonhydrocarbons and heavier natural gas liquids) 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 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 2024 and 2025.

Coalbed Methane and Shale Gas

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

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.

Initial Productivity Rates

Table S5.8 shows the forecast of initial average productivity for new natural gas by PSAC area, as well as shale and CBM wells. These values 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.

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.

Natural Gas Production Forecast Accuracy

The natural gas production forecast deviation has narrowed significantly in recent years, ranging from 14% in the 2022 report to only 1% in the 2025 report. The high deviation in the 2022 forecast reflects uncertainty surrounding geopolitical disruptions and industry-specific factors that affected market conditions during the forecast period. The 2025 forecast reflects improvements in our models and assumptions over time, allowing for more precise alignment with actual outcomes.

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 the oil sands and electricity generation depend on other forecasts, including crude bitumen production, total electricity demand, and growth in renewable electricity generation.

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

Supply Costs

The supply cost (break-even price) of a resource project is the minimum constant dollar price required to recover all capital expenditures, operating costs, royalties, and taxes, while also earning a specified return on investment. 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 natural gas liquids and sulphur
- a 10% nominal rate of return

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

Data

The AER uses natural gas production volumes submitted by industry to Petrinex. Petrinex is a secure, centralized information network used to exchange petroleum-related information. All 2025 data are as reported by industry through to the end of December and do not include any subsequent amendments.

5 Natural Gas Liquids Methodology

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 natural gas liquids content traced back to the reservoir and the amount of liquid that can be recovered (the liquid recovery factor) from representative fields, fractionation plants, and straddle plants.

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.

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 be stored or removed from the province, including as a mixed product such as liquified petroleum gas (LPG).

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.

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.

Data

All 2025 data are as reported by industry through the end of December and do not reflect any subsequent amendments. The AER uses volumes of natural gas liquids submitted to Petrinex by field plant, fractionation plant, and straddle plant operators.

6 Coal Methodology

Alberta produces three types of coal: subbituminous, metallurgical bituminous, and thermal bituminous. Forecasts for each type are based on supply and demand fundamentals.

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 growth potential for some of those mines. Only projects that have applied for provincial regulatory approval (permits, licences) will be considered in the forecast.

Demand Forecast

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.

Data

All 2025 data are reported by industry through the end of December and do not reflect any subsequent amendments. The AER uses historical data from the *ST26: Alberta Coal Industry Monthly Statistics* report for production and demand statistics.

7 Emerging Resources Methodology

Hydrogen Production Forecast

The methodology for the hydrogen 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 forecast were assessed for the likelihood of meeting their 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 regarding their likelihood of becoming operational within the next decade.

Forecast considerations and factors affecting each specific commodity are described below.

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 hydrogen forecast considered factors that may affect the pace of development, including complementary policies and de-risking projects through government partnerships.

Data

Hydrogen and Lithium Data

Hydrogen and lithium data are based on AER research and publicly available data.

Helium Data

Historical data are as reported by industry in Petrinex through the end of December and do not reflect any subsequent amendments.

Geothermal Data

Historical geothermal production was calculated using Alberta Electric System Operator hourly electricity generation data.

8 Carbon Capture, Utilization, and Storage (CCUS) Methodology

Sequestration Data

Historical data were reported by industry through the end of December and do not reflect any subsequent amendments. The monthly average density of the injected fluid, as reported in Petrinex, is used to convert the reported volumes to their mass equivalent. CCS sequestration volumes of CO_2 are sourced from Petrinex. The CO_2-EOR injection volumes reported in Petrinex represent gross volumes, which include CO_2 supplied from capture sites as well as CO_2 recirculated through the active oil and gas producing wells in the pool. The sequestered volume is calculated by subtracting the recirculated CO_2 from the gross injection volume.