
# AESO 2019
# Long-term Outlook

SEPTEMBER 2019

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# 1.0 Executive summary

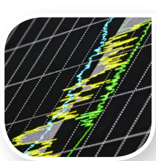
*The Alberta Electric System Operator (AESO) 2019 Long-term Outlook describes Alberta's expected electricity demand over the next 20 years, as well as the expected generation capacity needed to meet that demand.*

The *2019 Long-term Outlook* (2019 LTO) is the AESO's forecast of Alberta's load and generation requirements over the next 20 years, and is used as one of many inputs to guide transmission system planning, long-term adequacy assessments, and market evaluations.

Key factors that drive load growth and generation development were examined in order to understand their potential impacts in Alberta. Moderate load growth is expected over the next 20 years but at half the rate experienced in the previous 20-year period. Load growth is expected in the near term due to increased oilsands production and economic recovery as curtailments end.

Generation growth is also expected in the forecast term and natural gas is anticipated to be the primary fuel source to replace coal in the generation mix. The amount and pace of generation development is affected by technology costs, government policy, upcoming coal plant retirement decision and profitability expectations, among other factors. Alberta's competitive electricity market determines the generation investment required to reliably meet demand, and the 2019 LTO provides a view of what generation is expected to develop and where.

The 2019 LTO was developed during a period of uncertainty and the outlook covers a period of transformation of Alberta's electricity industry. Changes in economics, government policies, technology, and the way power is produced and consumed can significantly impact load growth and development of generation. To account for these uncertainties and possible outcomes, the AESO developed a series of scenarios in addition to its main corporate outlook.



> The 2019 LTO generation forecast is based on the load growth outlook, policy considerations, generation technology, and resource availability.

## 1.1 SCENARIO DEVELOPMENT

The 2019 LTO is built upon a Reference Case, the AESO's main corporate forecast to be used as an input to transmission planning and for other planning purposes, representing our current expectation of future long-term load growth and generation development. In addition, three load scenarios, four generation scenarios and one generation sensitivity were developed. In all scenarios, natural gas-fired generation is the dominant fuel type to replace coal and meet demand in the forecast period.

**Load scenarios:**

- High Growth Scenario
- Low Growth Scenario
- Diversification Scenario

**Generation scenarios:**

- High Cogeneration Sensitivity
- Alternate Renewable Policy Scenario
- High Growth Scenario
- Low Growth Scenario
- Diversification Scenario

The use of scenarios allows the AESO to comprehensively assess our assumptions of key uncertainties and consider a variety of potential outcomes. The AESO continually monitors economic, policy and industry developments that could affect the forecast, resulting in further consideration of alternate scenarios to align with the latest information. If a scenario becomes more likely, the AESO may adopt it as its main forecast.

## 1.2 BUILDING THE 2019 LONG-TERM OUTLOOK

The AESO develops comprehensive outlooks and validates them against other reputable forecasting experts. The AESO also seeks input from industry stakeholders, including generation developers and distribution facility owners, to gather information that informs our assumptions. The AESO is dedicated to constant improvement and welcomes feedback on our forecast processes.

The 2019 LTO includes a number of assumptions regarding economic growth and future policy outcomes. The foundation of the forecast is the provincial economic outlook because economic growth is a key driver of electricity demand in Alberta. Economic growth is largely dependent on the oilsands industry, and it is assumed that oilsands development will grow at a modest pace, despite the continued expectation of reduced oil prices.

Policies and support programs affect both load and generation in Alberta. The 2019 LTO includes assumptions about several federal and provincial policies that are under development at time of writing. These policies are detailed in Section 3.0.

## 1.3 KEY HIGHLIGHTS

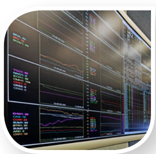
- The Reference Case Scenario is the AESO's main corporate forecast for long-term load growth and generation development in Alberta.
- Load is forecast to grow at a compound annual growth rate of 0.9 per cent until 2039. This is approximately half the rate of growth Alberta experienced in the past 20 years.
  - The load forecast is very similar to the 2017 LTO because of a similar long-term economic outlook for Alberta.
- The generation outlook provides a view of what Alberta's competitive electricity market would be expected to develop over the forecast period to meet forecast demand reliably.
  - Approximately 13 GW of new generation capacity is expected to develop by 2039 for a total Alberta capacity of 22,815 MW.
  - Natural gas-fired generation will become the predominant generation source as 5,275 MW of coal-fired capacity is expected to co-fire or convert to natural gas beginning in 2021.
  - Near-term renewable generation will develop from Renewable Electricity Program projects and Alberta Infrastructure's support for solar programs.
  - Additional unsubsidized renewable generation is expected to develop through competitive market mechanisms and support from corporate Power Purchase Agreements (PPAs).
- In addition to the Reference Case, three load scenarios, four generation scenarios and one generation sensitivity were developed to address key known uncertainties.
- Key highlights and assumptions of the scenarios:
  - The High Cogeneration Sensitivity tests the impacts of increasing the amount of cogeneration capacity at existing and future oilsands sites, above levels assumed in the Reference Case Scenario.
  - The Alternate Renewable Policy Scenario tests higher renewable development, based on a target in line with observed renewable portfolio standards common in other jurisdictions.
  - The High Growth Scenario tests higher economic growth in the province due to continued strong oilsands growth.
  - The Low Growth Scenario tests lower economic growth in the province due to a stagnating oilsands industry.
  - The Diversification Scenario considers a shift in Alberta's economy away from oil and gas and towards new technologies and industries. In addition, it tests higher penetrations of new generation technologies including solar and energy storage.

# 2.0 Background

*The 2019 LTO will be used as the foundation for the AESO's next Long-term Transmission Plan, which sets out Alberta's future transmission requirements.*

The 2019 LTO is the AESO's long-term forecast of Alberta's expected future demand and energy requirements over the next 20 years, along with the expected generation capacity to meet those requirements. The 2019 LTO will be used by the AESO as the foundation for the *2020 Long-term Transmission Plan* (LTP), as required by the *Transmission Regulation*.

In addition to the LTP, the LTO is used as input into other AESO functions. These include transmission system planning for Needs Identification Documents (NIDs) and connection projects, the ISO tariff and market assessments. The LTO will also inform ongoing energy-only market evaluations, providing guidance to the level of generation required to be developed in the market to reliably meet demand. The AESO continually reviews its forecasts and will, if appropriate, consider alternate load and/or generation assumptions in these other functions in order to align studied forecasts with the latest information.



> To ensure the 2019 LTO aligns with current and expected trends, the AESO continually monitors relevant industry developments that may affect future load growth and generation development.

## 2.1 POLICY IMPACTS AND UNCERTAINTIES AFFECTING THE 2019 LTO

### 2.1.1 Policy Impacts

Changing policies and economic drivers can significantly impact the development of load and generation in the province. With the development of the 2019 LTO, strategies have been applied by the AESO to be prepared and flexible for a number of possible outcomes. The 2019 LTO faces uncertainty of policy outcomes at the provincial and federal level. To assess the impacts of some of these possible policy initiatives and outcomes, the 2019 LTO contains a diverse set of scenarios. This scenario-based approach, along with narratives, assumptions and results, are described in further detail in Section 6.

### 2.1.2 Uncertainties

This 2019 LTO was developed during a period of uncertainty for Alberta's electricity industry. The industry is currently in a state of transition as new policies are implemented and as coal-fired generation is phased out or converted to natural gas generation. The AESO was directed by the previous government to administer three rounds of the Renewable Electricity Program (REP), and future rounds have been discontinued by the current government. Under current policy, the quantity and pace of integrating additional renewables to the grid is expected to be driven primarily by market decisions.

Further uncertainty exists due to potential, but yet-to-be-determined policies and programs at the provincial and federal level. These could impact the province's future electricity supply mix, as well as the amount and pace of development of renewables and cogeneration. In addition, economic uncertainty exists around the load forecast related to oilsands development and overall economic growth. To quantify these sources of uncertainty and ensure that the AESO understands their potential impact, specific assumptions were made, and a scenario-based approach was adopted for the 2019 LTO.

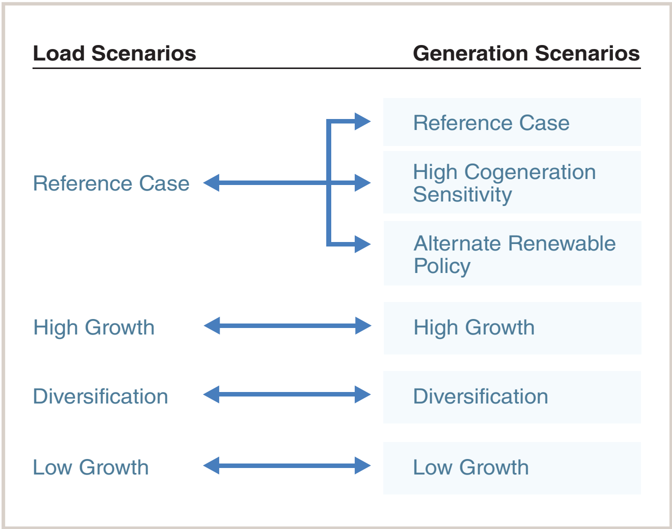
As part of this strategy, the 2019 LTO contains a Reference Case Scenario (Reference Case), which is the AESO's reference point and corporate forecast to be used as an input to transmission planning and for other planning purposes. The Reference Case represents the AESO's current expectations for long-run load growth and generation development given major uncertainties facing the industry. The Reference Case makes multiple assumptions regarding the future of load and generation development in Alberta. It is expected that, over the course of 2019 and beyond, new information will become available, providing direction which may differ from the assumptions outlined in this document. In addition to the Reference Case, the AESO developed scenarios to understand and test additional key uncertainties facing the load and generation forecast.

## 2.2 LONG-TERM OUTLOOK METHODOLOGY

### 2.2.1 Scenario-based Analysis

The 2019 LTO is structured around a set of scenarios that include both load and generation (see Figure 1). Scenarios allow the AESO to test uncertainties by making specific assumptions about developments or outcomes in order to answer “what if?” questions. The 2019 LTO scenarios address a holistic set of outcomes under alternate expectations for the future, comprehensively testing key unknowns of load and generation in Alberta.

**FIGURE 1: Scenario Overview**




Details about each scenario, including background and assumptions, are presented in Section 6. Both a generation and a load outlook are included for each scenario.

### 2.2.2 2019 LTO Reference Case Scenario

The 2019 LTO Reference Case Scenario is consistent with the most recent information and announcements pertaining to Alberta’s electricity industry. Due to ongoing policy discussions which could cause further impacts, and the uncertainty faced in the next 20-year period, the AESO remains neutral towards any given outcome.

Despite the adoption of the Reference Case as its main corporate outlook, the AESO also considers other potential scenarios until they can be ruled out. These scenarios provide the AESO with the necessary tools to understand potential impacts from different load and generation outlooks and capture key known uncertainties for appropriate planning. These uncertainties, such as economic activity, capital cost decreases for renewables and battery technology, and provincial and federal government policies and programs, influence both the pace and magnitude of load and generation development.

The additional scenarios developed for the 2019 LTO are:

- **High Cogeneration Sensitivity:** this sensitivity tests the impact of increasing the amount of cogeneration capacity at oilsands sites above levels assumed in the Reference Case.
- **Alternate Renewable Policy Scenario:** assumes the same load growth as the Reference Case with an increased renewables generation target in line with observed renewable portfolio standards common in other jurisdictions. It is informative to test the effects of such a target for the province over the next 20 years.
- **High Growth Scenario:** assumes a robust economic recovery led by the development of new load projects and electric vehicles. While the generation assumptions are similar to the Reference Case, cogeneration additions experience greater growth as oilsands growth increases.
- **Low Growth Scenario:** assumes economic growth is limited due to the absence of new oilsands projects, and other factors such as energy efficiency gains and an increased adoption rate of photovoltaic (PV) rooftop solar. While the generation assumptions are similar to the Reference Case, with decreased growth in the oilsands, the amount of assumed cogeneration growth is reduced.
- **Diversification Scenario:** assumes that Alberta's economy shifts away from oil and gas and towards other more diversified sectors to fuel economic growth. This scenario tests greater generation diversification with higher wind, energy storage, and solar penetration.

### 2.2.3 Multiple Outcomes

Within any given scenario, assumptions are made in order to model the impacts; however, there may be alternate assumptions that could be reasonably included under any specific scenario. These uncertainties are described where applicable. Although the scenario-specific uncertainties are not explicitly explored in the 2019 LTO, they will be continually assessed and monitored for impacts.

# 3.0 Key forecast drivers

This section highlights the key economic forecast and policy drivers used in the creation of the 2019 LTO forecast.

## 3.1 KEY ECONOMIC FORECAST DRIVERS

The economic outlook lays the foundation for the 2019 LTO. It is focused at the provincial level and considers key factors driving the Alberta economy. The economic outlook is derived from the Conference Board of Canada's (CBoC) annual long-term provincial economic forecast, released in March 2018.[1]

### 3.1.1 Economic Drivers and Assumptions

A key factor affecting electricity demand in Alberta over the long term is economic growth. This section discusses the economic considerations and assumptions underpinning the Reference Case load forecast.

Alberta's economy is highly correlated with oil prices due to the size of its oil industry, especially the oilsands. In Canada, western Canadian oil prices have been depressed more than global prices, making oilsands projects less profitable. It is expected that with reduced potential for oil price increases, oilsands development will continue to expand but at a more modest pace.

Similar to the 2017 LTO, it is expected that smaller brownfield expansions will be the norm for the oilsands industry. These smaller brownfield projects require significantly less capital investment, are quicker to build and scale, remain profitable at lower oil prices, and pose lower risk to developers. Similarly, conventional oil development is negatively impacted by lower oil prices, further reducing expectations for economic growth in Alberta. The reduced oil price outlook and resulting modest pace of anticipated oilsands development impacts the overall Alberta economy.

There is still considerable uncertainty about future oil prices and their effects. Reduced profits associated with oil extraction will likely lead firms to curtail their investment in the oil and gas sector. However, a lower Canadian dollar plays an important role in facilitating the economy's adjustment to the oil price reduction. In particular, the lower Canadian dollar will support non-energy exports and employment and also play a buffering role for oil producers. Energy firms are better equipped to operate in a low oil price environment because they have innovated and improved efficiency in various ways, including by cutting overhead costs.

In 2019, the Government of Alberta implemented an oil production limit which is currently scheduled to end on Dec. 31, 2020.[2] The length and extent of this limit creates uncertainty around oil production in the near term, and impacts are not considered in the long-term oilsands forecast as they are expected to be temporary and limited.

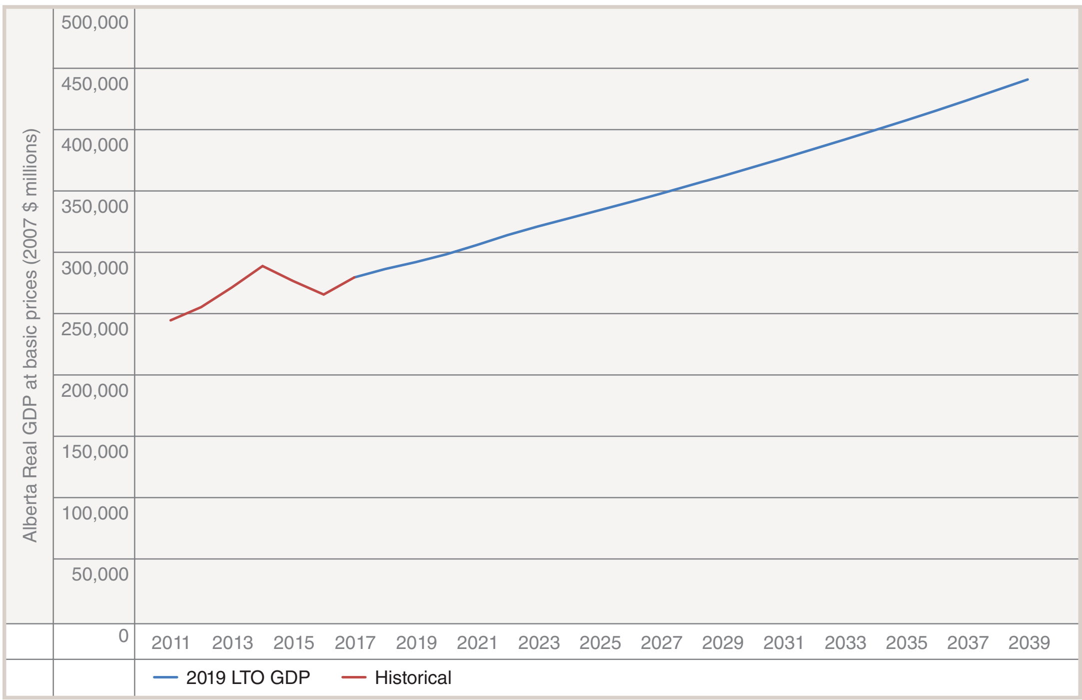
1 The Conference Board of Canada. Provincial Outlook Long-Term Economic Forecast: Alberta—2018. Ottawa: The Conference Board of Canada, 2018. https://www.conferenceboard.ca/e-library/abstract.aspx?did=9564

2 https://www.alberta.ca/oil-production-limit.aspx

### 3.1.2 Economic Assumptions

The 2019 LTO's Gross Domestic Product (GDP), population, and employment forecasts are sourced from The Conference Board of (CBoC). The CBoC's *Provincial Outlook Economic Forecast for Alberta* (Summer 2018) is used for the years 2018 to 2022[3] and the *Provincial Outlook Economic Forecast for Alberta* (released March 2018) is used for the years 2023 to 2039.[4]

**FIGURE 2: GDP Forecast**




### 3.1.3 Oilsands Assumptions and Production Forecast

Oilsands production is included in the Alberta Internal Load (AIL) model to measure the impact of oilsands production on electricity demand. This forecast includes the production of synthetic crude oil and non-upgraded bitumen. The 2019 LTO's oilsands production forecast is sourced from the Canadian Association of Petroleum Producers (CAPP) 2018 *Crude Oil Forecast* up to the year 2035 with a linear extrapolation of CAPP's forecast from the year 2036.

In addition to CAPP, IHS Markit forecasts oilsands production in Alberta out to the year 2050. The IHS Markit oilsands forecast was used to inform the linear extrapolation forecast from 2035 to 2039, which shows that oilsands growth slows down after 2035.[5] The resulting oilsands production forecast for the 2019 LTO Reference Case is a 1.3 million barrels per day increase from 2018 to 2039.

3 The Conference Board of Canada. Provincial Outlook Economic Forecast: Alberta - Summer 2018: The Conference Board of Canada, 2018. https://www.conferenceboard.ca/e-library/abstract.aspx?did=9871

4 The Conference Board of Canada. Provincial Outlook Long-Term Economic Forecast: Alberta—2018. Ottawa: The Conference Board of Canada, 2018. https://www.conferenceboard.ca/e-library/abstract.aspx?did=9564

5 IHS Markit North American Crude Oil Markets Q2 2018 Forecast

In order to determine which projects are included in the 2019 LTO, a consistent assumption is used across all connection projects that have applied to the AESO. All AESO Stage 5 connection projects that have regulatory approval from the provincial and federal governments are included. For oilsands sites, load growth is almost entirely from existing sites. This is supported by the IHS Markit forecast that states most oilsands growth will occur at existing sites.

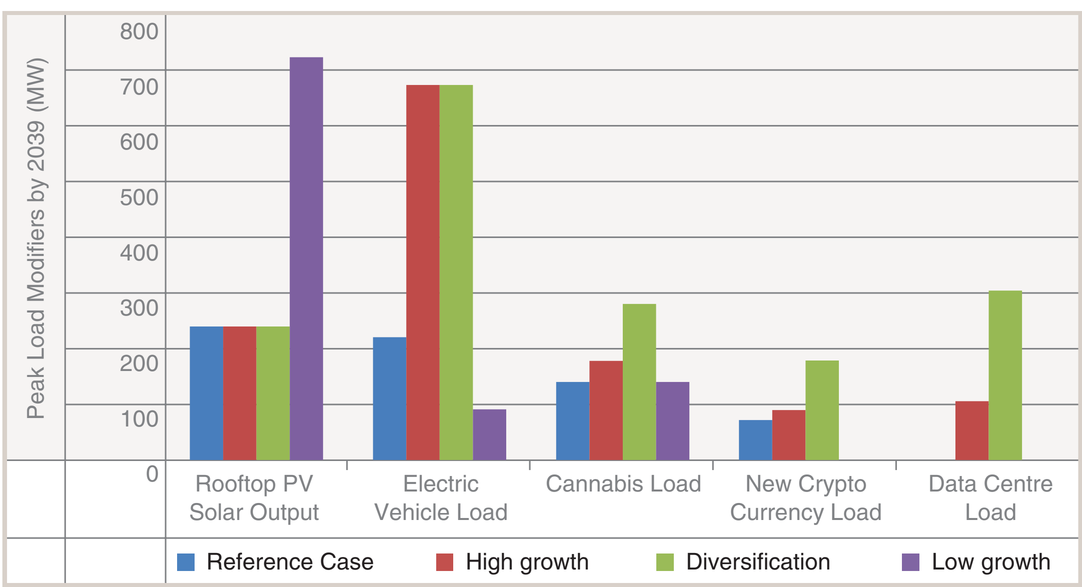
Economic uncertainty surrounding future oilsands production is accounted for in the load scenarios. The High Growth Scenario considers what would be expected if oilsands production increases more than anticipated, and the Low Growth and Diversification Scenarios consider the potential for oilsands to stop expanding past 2021.

### 3.1.4 New Load Modifiers in the Forecast

Alberta's electricity industry and technologies are dynamic and constantly evolving. The electricity industry is on the cusp of transformational change driven by technology advancements, digitalization, and changing consumer preferences and demographics – all leading to a profound impact on the electricity value chain. To ensure the 2019 LTO aligns with current and expected trends, the AESO continually monitors relevant industry developments that may affect future load growth and generation development.

The AESO has carefully considered several load modifiers that have emerged rapidly in the last few years. The Reference Case load forecast makes explicit assumptions about the cannabis farming industry, rooftop solar photovoltaics, cryptocurrency mining operations, and electric vehicles. Details of the analysis are described in Appendix C. While cryptocurrency mining operations and the cannabis farming industry lead to higher load growth in the near term, electric vehicle adoption adds to load more rapidly as adoption increases in the longer term. Rooftop solar contributes to a considerable decline in grid-served load over the longer term. Figure 3 shows the impact of these load modifiers on each scenario.

**FIGURE 3: Load Modifiers Included in Each Scenario**



### 3.2 POLICY DRIVERS AND ASSUMPTIONS

Environmental laws and policies affect the economics and incentives of electricity market participants, impacting the future of electricity demand and supply in Alberta. In addition to the current regulations, legislation, and programs, there are a number of federal and provincial initiatives and policies which are being considered and may be implemented. Consideration is given to those policies that are still in development and the impact they could have on generation.

#### 3.2.1 Federal Policies on Coal-fired and Gas-fired Electricity Emissions

The Government of Canada published two final regulations in the *Canada Gazette*, Part II, on Dec. 12, 2018:

1) Amendments to the *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations* (2012) will accelerate the phase-out of conventional coal-fired electricity units to Dec. 31, 2029.
2) *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity* (2018) provides CO2 emission intensity standards for natural gas-fired electricity. These regulations cover new gas-fired units and coal-fired units that are converted to run on natural gas.[6]

The federal standards on coal-fired and gas-fired generation impact the generation mix over the 20-year forecast. The coal-fired regulation sets the emission standards and the end-of-life for coal-fired units, impacting how long they can operate. Further, if the units convert from coal to gas, these regulations dictate the longest they will be allowed to operate based on their efficiency. In the 2019 LTO, assumed retirement dates for coal-fired and coal-converted units have been informed by the regulations. Details on the assumed retirement dates can be found in Appendix B.

***Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations***

The amendments to this regulation accelerate the phase-out of conventional coal-fired electricity across Canada by requiring all units to meet an emission standard of 420 tonnes of CO2 per gigawatt hour (t/GWh) at the end of their useful life or by Dec. 31, 2029, whichever is sooner. Owners and operators of units can also meet this performance standard by installing carbon capture and storage. The main impact of this federal regulation on Alberta's coal-fired units is that it limits the useful life of the units.

***Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity***

These regulations cover new natural gas-fired generation units that sell or distribute more than 33 per cent of their potential output to the electricity grid, have a minimum installed capacity of 25 MW, and receive more than 30 per cent of their heat input from natural gas. New units are considered those installed and commercialized after January 2021.

[6] http://www.gazette.gc.ca/rp-pr/p1/2016/2016-12-17/html/notice-avis-eng.html
http://www.gazette.gc.ca/rp-pr/p2/2018/2018-12-12/html/index-eng.html
https://www.canada.ca/en/environment-climate-change/services/managing-pollution/energy-production/technical-backgrounder-regulations-2018.html
https://www.canada.ca/en/environment-climate-change/services/climate-change/greenhouse-gas-emissions/regulations/coal-fired-electricity-generation.html

All new units with an installed capacity of 25 MW to 150 MW will have to meet a performance standard of 420 t/GWh, based on an annual average. Smaller units that are 150 MW will have to meet a standard of 550 t/GWh, reflecting the more frequent need for these units to ramp up quickly to integrate variable renewable generation like wind and solar.

This regulation also establishes conditions for the operation of coal units converted to run on natural gas. Units converted from coal to gas that meet a conversion-specific performance standard will be allowed to operate for a fixed period of time after their end-of-life, after which they will have to meet the same performance standard of 420 t/GWh as new units.

***Federal Output-Based Pricing System (OBPS)***

The federal government has released their Output-Based Pricing System (OBPS) which is designed as a backstop to ensure there is a price incentive for industrial emitters to reduce their greenhouse gas (GHG) emissions. The OBPS regulations were released on June 28, 2019. Under the OBPS, industrial facilities that emit 50,000 tonnes or more per year pay a price on pollution starting at $20 a tonne, rising to $50 a tonne in 2022. For electricity generators, the standard that units are benchmarked against is specific to the fuel type and size of the unit. For any natural gas generating assets constructed after Dec. 31, 2020 that are greater than or equal to 50 MW in size, the benchmark starts at 370 t of CO2/GWh in 2021 and reduces in a linear fashion to 0 t of CO2/GWh in 2030. If the unit is less than 50 MW, the 370 t of CO2/GWh threshold continues in perpetuity.

The 2019 LTO has not explicitly created a scenario that tests the impact of the federal OBPS, as the forecast is predicated upon provincial carbon policy, which is assumed to achieve a level of equivalency to the federal OBPS.

### 3.2.2 Provincial Policies on Electricity Emissions

***Technology Innovation and Emissions Reduction Program and the Alberta Emissions Offset System***

The Alberta government announced the Technology Innovation and Emissions Reductions (TIER) regime for large industrial emitters in Alberta will be effective Jan. 1, 2020. Under this proposed system, large final emitters (LFEs) in the electricity sector will be required to meet a "good-as-best-gas" performance standard. The compliance price was announced to be reduced from $30/tonne to $20/tonne, and a TIER Fund will be implemented to help companies reduce emissions with cleaner technology.

Emission offsets can be achieved by either reducing facility emissions, purchasing credits from facilities that have exceeded their compliance targets, purchasing accredited offsets from emission reductions occurring elsewhere in the Alberta economy, or paying into the TIER Fund at a rate of $20/tonne. Emission offsets are generated by projects that have voluntarily reduced their greenhouse gas emissions. Emission offset projects must meet the requirements in the *Carbon Competitiveness Incentive Regulation,* the *Standard for Greenhouse Gas Emission Offset Project Developers,* and a relevant Alberta-approved quantification protocol.

The TIER program has provided the basis for the cost of carbon emissions within the 2019 LTO. At the time of developing the 2019 LTO, information about the program suggested a carbon price of $20/tonne and a good-as-best-gas performance standard. These two cost components have been used within the forecast. Since the creation of the forecast, further consultation on the program has taken place that may change these assumptions in the future. The Government of Alberta is currently consulting with stakeholders to finalize the TIER regulation by Jan. 1, 2020.

Uncertainty in future carbon pricing is tested through scenarios that provide impacts to the generation fleet and commensurate insights for the AESO's planning and market assessments.

***Clean Air Strategic Alliance (CASA)***

The CASA Electricity Emissions Management Framework is a framework for managing air pollution, developed by a multi-stakeholder alliance composed of representatives from industry, government and non-government organizations. The alliance is tasked with providing strategies to assess and improve air quality for Albertans using a collaborative consensus process. Under this framework, all coal-fired generating units will have to comply with their environmental permits related to sulphur dioxide (SO2) and nitrogen oxides (NOX) emission standards at the end of design life. Units can comply with CASA through credits, installing abatement equipment, or by retiring.

In December 2018, a sub-group of the CASA alliance provided an interim report summarizing the work undertaken on NOX emission standards for natural gas-fired turbines. This project team will be resuming work in the fall of 2019.[7]

The 2019 LTO considers NOX emission controls by factoring in the cost of abatement through selective catalytic reduction (SCR) units. The impacts of the SCR investments are embedded in the capital cost assumptions and affect the generation economics of affected assets.

### 3.2.3 Renewable Energy Programs

Recently, federal and provincial programs have funded and supported the development of renewable projects within Alberta. Renewable projects that have been awarded contracts or have received financial support through these programs are anticipated to develop within the province. These programs only impact the near-term development of renewable supply additions within the 2019 LTO since the programs typically had set budgets for support or were discontinued.

Under the most current policies, new renewable electricity projects will need to be financed and built in Alberta based on market-based decisions and without government-based offtake agreements. They are unlikely to receive substantial “out-of-market” payments or subsidies and will be treated similar to other generation projects.

The Reference Case and other scenarios include near-term renewable generation additions from the programs mentioned below. While the 2019 LTO assumes these generation additions will be utility scale, it is reasonable to expect that some of them will be smaller scale. The 2019 LTO Reference Case and scenarios contain solar additions which are consistent with the Government of Alberta’s solar programs.

***Natural Resources Canada’s Emerging Renewable Power Program***

The Emerging Renewable Power Program provided up to $200 million to expand the portfolio of commercially viable renewable energy sources available to provinces and territories working to reduce GHG emissions from their electricity sectors. This program allowed emerging renewable power generation to play a larger role in Canada’s electricity supply mix through federal government funding. The program established new industries in Canada by supporting renewable power technologies that are either already established at the commercial level abroad but not yet in Canada, or demonstrated in Canada but not yet deployed at a utility scale.[8] The Request for Project Applications under the Emerging Renewable Power Program is now closed.

7 https://www.casahome.org/

8 https://www.nrcan.gc.ca/climate-change/green-infrastructure-programs/emerging-renewable-power/20502

### *Renewable Electricity Program*

The *Renewable Electricity Act* of 2016 established the Renewable Electricity Program (REP) in order to encourage the development of new renewable electricity generation capacity connected to the Alberta grid. At the previous Government of Alberta's direction, the AESO administered three rounds of the REP resulting in an anticipated 1,360 MW of new wind generation, and future rounds have been discontinued by the current government.[9]

### *Alberta Infrastructure Solar Request for Proposals*

In October 2018, the Government of Alberta issued a Request for Proposals (RFP) to procure enough solar power to meet approximately half of the government's annual electricity needs. This will allow the province to replace existing green energy contracts with solar power. The RFP was issued to replace two contracts that expired at the end of 2017. The third contract will expire in December 2024, and future government procurements are uncertain at this time.[10]

Through this RFP, the government is committed to purchasing Renewable Energy Certificates (RECs) equivalent to 135,000 megawatt hours (MWh) of solar-generated electricity, or approximately equivalent to 80 MW of solar capacity each year for the next 20 years. In February 2019, Canadian Solar was awarded three solar power contracts from Alberta's Ministry of Infrastructure, for a total of 94 MW of solar power in southeast Alberta. When in operation in 2021, these solar plants will provide Alberta's provincial government with 55 per cent of their electricity needs.

### *Other Renewable Generation Programs*

There are a number of other smaller renewable generation support programs in Alberta fostering development in the residential, municipal, community and Indigenous sectors. These various programs are intended to support smaller-scale and community-scale renewables and alternative generation resources.

## 3.2.4 Micro-generation

Under the *Electric Utilities Act* (EUA), the *Micro-generation Regulation* allows Albertans to meet their own electricity needs by generating electricity from renewable or alternative energy sources. Micro-generators that produce excess electricity receive credits for what they feed to the grid. There are two types:

1) Small micro-generators (under 150 kilowatts) are credited for the electricity sent back to the grid on a monthly basis at their retail rates, and they may also install a meter to receive credit for excess electricity based on hourly wholesale market prices.
2) Large micro-generators (sized 150 kilowatts and above) are credited for the electricity sent back to the grid at the hourly wholesale market price. A micro-generation system is limited to a size of five megawatts (MW), and is allowed to serve adjacent sites.[11]

[9] https://www.aeso.ca/market/renewable-electricity-program/
http://www.qp.alberta.ca/documents/Acts/r16p5.pdf

[10] https://www.alberta.ca/release.cfm?xID=6073319EECE4D-FCB2-82B9-E2A3B45BF930BCA2
https://solaralberta.ca/grants-and-incentives
https://www.renewableenergyworld.com/articles/2019/02/alberta-government-signs-ppa-for-94-mw-of-subsidyfree-solar.html
https://albertapowermarket.com/2017/06/05/update-on-albertas-solar-pv-electricity-procurement/

[11] http://www.qp.alberta.ca/documents/Regs/2008_027.pdf ; https://www.aeso.ca/market/market-and-system-reporting/micro-generation-reporting/

The 2019 LTO does not have an explicit micro-generation forecast but includes small-scale photovoltaic (PV) rooftop solar capacity additions, which is discussed in detail in Appendix C. These PV rooftop solar additions are assumed, for modelling purposes, to reduce corresponding load in the province.

### 3.2.5 Energy Efficiency

Energy Efficiency Alberta (EEA) is a Government of Alberta agency established in January 2017. Its mandate is to raise awareness about energy use and promote, design, and deliver programs and other activities related to energy efficiency, conservation and the development of micro-generation and small-scale energy systems in Alberta. EEA has implemented a number of programs since its inception such as the residential, business, and institutional energy savings programs, and the commercial solar program.[12]

The Reference Case load forecast accounts for the relationship between load growth and economic growth, which has changed over time in Alberta. This relationship is used to determine the level of energy efficiency that is expected to occur in the future. Historically the relationship has decreased, as a given level of economic growth creates less load growth today compared to ten years ago due to increases in energy efficiency.

As Alberta's load customers become more efficient, increases in energy efficiency from a number of houses or increased oil production creates a smaller amount of load growth. The 2019 LTO assumes that historical efficiency gains will continue at the same rate into the future. Further details on the energy efficiency assumptions and methodology are discussed in Section 4.1.2.

[12] https://www.efficiencyalberta.ca/

# 4.0 2019 LTO Reference Case Scenario

The AESO's Reference Case Scenario can be characterized as the base case. The Reference Case incorporates recent information and announcements with respect to demand and supply of electricity in Alberta at the time of the 2019 LTO development. This encompasses announcements made by the Government of Alberta, the federal government, and major stakeholders.

While the 2019 LTO Reference Case Scenario is consistent with recent information and announcements pertaining to Alberta's electricity industry, changes to ongoing policy discussions could cause further impacts. The AESO remains neutral towards the outcome of any given scenario and considers all potential scenarios until they can be ruled out, despite the adoption of the Reference Case as its primary corporate forecast.

Load and generation data relating to the Reference Case and scenarios are available in the 2019 LTO Data File at *www.aeso.ca/grid/forecasting*.

## 4.1 REFERENCE CASE LOAD FORECAST

The Reference Case load outlook represents the AESO's base case estimate of future load growth. It is aligned with the Reference Case economic outlook and leverages a new load forecast methodology. In addition to the economic variables, other new variables are added to the load forecast over the long-term horizon.

This section describes the methodology, assumptions and inputs used to create the hourly AIL, Planning Region, Planning Area and Point-of-Delivery (POD) load forecasts. The 2019 LTO load forecast includes both an improvement in AESO's load forecasting methodology and the addition of new load modifiers. A comparison with the 2017 LTO forecast is detailed in the Results sections.

### 4.1.1 2019 LTO Load Forecasting Methodology

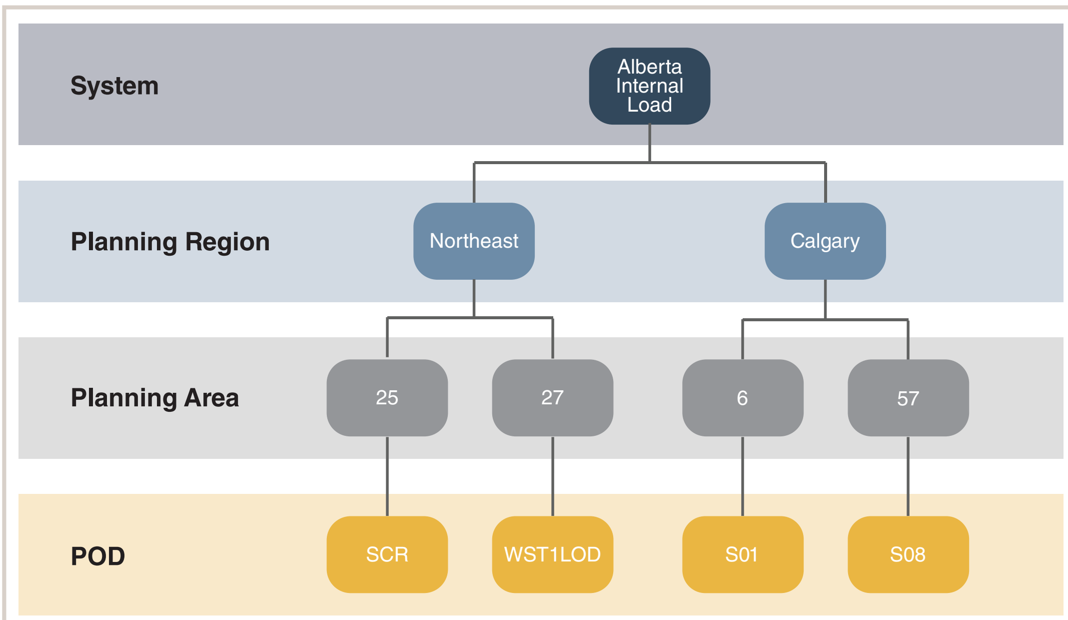
The 2019 LTO forecast methodology leverages a new load forecasting tool and considers new technologies and industries that have recently started impacting Alberta's electricity demand.

The 2019 LTO load forecast was developed using a modelling framework and tool based on SAS Energy Forecasting – a load forecasting software that models hourly load data and drivers, and forecasts hourly load out 20+ years into the future. The tool models Alberta load across different granularities (PODs, areas, regions, and the whole province) using historic load and input variables such as real GDP, population, employment, oilsands production, temperature, time of day, time of week, and time of year. The forecast includes the economic variables outlook, and the weather profile uses the 90th percentile of the last 10 years of historical weather.

The 2019 LTO improves the forecasting process by applying econometric models. As shown in the example in Figure 4, a reconciliation process is carried out to ensure that the POD, area and regional forecasts add up to the AIL forecast. The POD-level econometric forecasts are reconciled to the area, region and AIL forecasts using a top-down reconciliation. Regions are first reconciled to AIL, then areas to region, and then PODs to areas. Reconciliation will adjust PODs based on the size of each site (i.e. larger PODs receive a larger portion of the impact of reconciliation). New load modifiers which capture new load behaviors not apparent in the historical data are then layered on top of the reconciled output.

The econometric modelling and the reconciliation process in the 2019 LTO is an improvement from previous LTOs because it makes the forecast more calculation-based and less subjective. POD forecasts rely on economic inputs to forecast load and the reconciliation process adjusts POD, area and regional forecast based on the relative size of each site.

**FIGURE 4: Modelling and Reconciliation Process**




Projects are included at the POD level in the SAS tool. If the project is a new POD, a new POD is included in the hierarchy. If the project is an expansion to an existing POD, the model is updated to include the project growth. Since all PODs, including new projects, are reconciled to the AIL forecast, it is the econometric AIL forecast that guides the overall growth in the forecast. New projects contribute to the overall growth forecast by the AIL outlook.

Project criteria in the 2019 LTO aims to include projects that have the highest probability of materializing. The general rule for project inclusion is all AESO Stage 5 connection projects and all Stage 1 through 5 DTS changes. Exceptions are made on a case-by-case basis based on regulatory hurdles, historic load growth if the project is an expansion to an existing site, and whether there is any government funding for the project.

### 4.1.2 Load Forecasting Assumptions

The Reference Case load growth is based on an economic-driven AIL forecast which is then adjusted for energy efficiency. The energy efficiency assumption was derived using historic energy efficiency gains in Alberta, and is intended to capture expectations of policy and non-policy-driven energy efficiency gains within the province. The efficiency improvements are assumed to impact all sectors of the economy, including oilsands, residential and commercial load.

The overall impact of these energy efficiency improvements results in a 1.7 per cent or 251 MW decrease in winter peak by 2039 compared to if no energy efficiency was applied to the forecast. Energy is forecast to decrease by 2.1 per cent or 2,186 GWh by 2039 compared to if no energy efficiency was applied. The forecast of energy efficiency is based on efficiency gains that Alberta has experienced over the past 20 years.

The impact of the energy efficiency assumption on the load forecast is relatively small. Energy efficiency gains are expected to come from improved technology in the oilsands and improved efficiency in residential, commercial and non-industrial sectors. These modest assumptions are supported by historic declines, based on the historic relationship between economic growth and load growth. The Low Growth Scenario tests the impact of a higher energy efficiency assumption on load growth, and alternative energy efficiency outlooks are explored in the other scenarios.

### 4.1.3 Reference Case Load Forecast Results

In the near term, the AESO expects load growth in line with historic trends due to recently completed and existing under-construction oilsands projects alongside improved economics in 2019 and 2020. In the medium and long term, once all oilsands projects under construction are complete, the AESO expects that load growth will follow a slower long-run trend as small-scale expansions at oilsands sites and slower GDP growth become the new norm.

Figures 5 and 6 show the load forecast results for the summer and winter peaks. The Reference Case load forecast is moderately higher than the 2017 LTO Reference Case in the near term. This increase is due to a higher oilsands outlook and the addition of new load which impacted recent load growth. In the longer term, however, the 2019 LTO load forecast is very similar to the 2017 LTO load forecast due to a similar long-term economic outlook for Alberta. The 20-year compound annual growth rate (CAGR) for the 2019 LTO is 0.9 per cent (2018-2039) compared to 1.0 per cent for the 2017 LTO (2017-2037).

Additional details on the Reference Case Load Scenario, including regional data, can be found within the 2019 LTO data file available at *www.aeso.ca/grid/forecasting.*

**FIGURE 5: Winter Peak AIL Forecast**

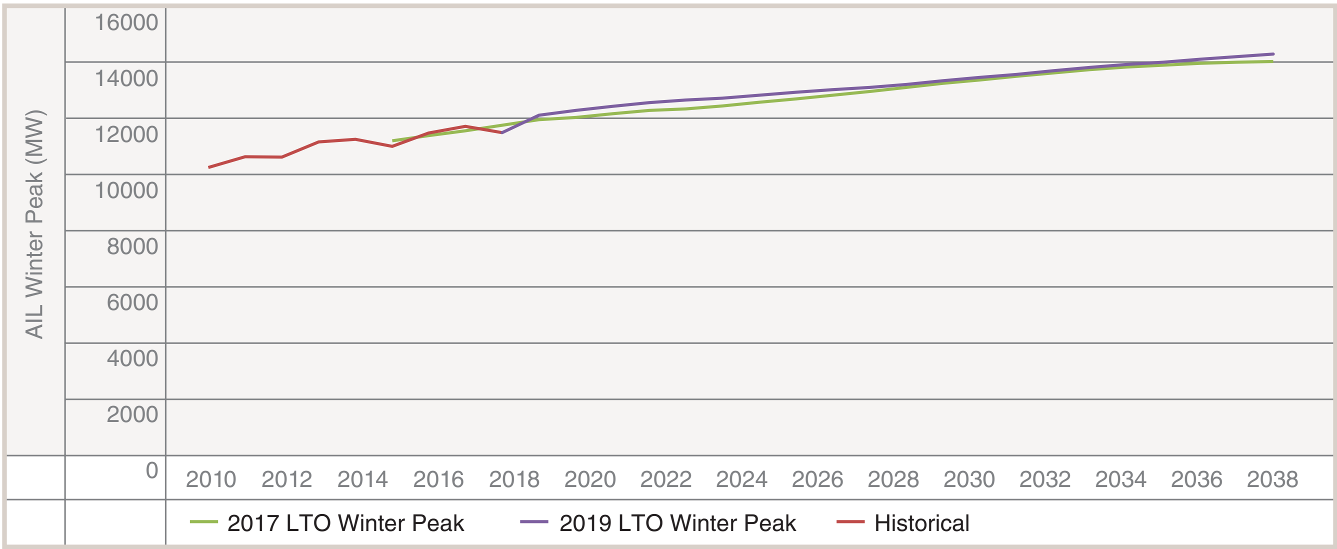
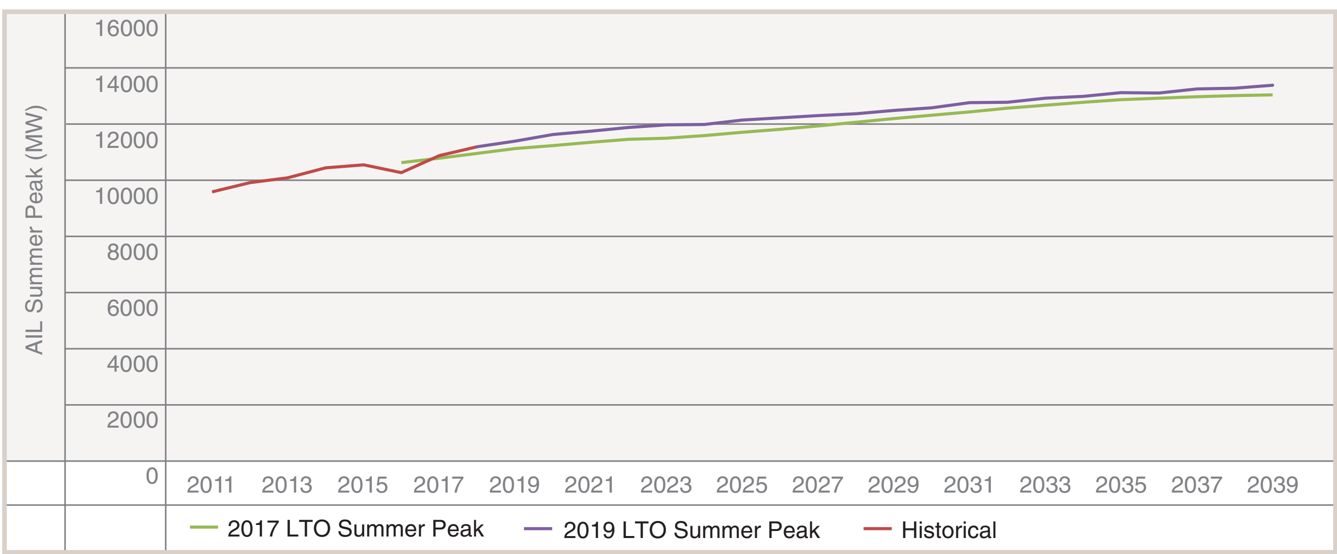



**FIGURE 6: Summer Peak AIL Forecast**



## 4.2 REFERENCE CASE GENERATION FORECAST

Generation development in the 2019 LTO has two main objectives: ensuring an adequate level of supply to meet demand; and aligning with known policy directions that impact generation development, such as announced carbon prices and coal-fired retirements from regulations. The AESO's Reference Case generation forecast is aligned with the Reference Case load forecast. It incorporates recent information and announcements with respect to the supply of electricity in Alberta at the time the 2019 LTO was developed. This includes announcements by the Government of Alberta, the federal government, and developers.

The Reference Case is based on an early understanding of the proposed TIER program, as described in section 3.2.2. Under this new system, large final emitters (LFEs) in the electricity sector will be required to meet a "good-as-best-gas" performance standard and this standard is assumed to be similar to the *Carbon Competitiveness Incentive Regulation* (CCIR). The compliance price for carbon emissions above the good-as-best-gas standard is assumed at $20/tonne.

In this scenario, current and expected generation economics drive the majority of outcomes. Renewable developments are driven by market-based decisions, incorporating capital cost declines, technological advancements and potential for corporate PPAs.

The Reference Case and other scenarios assume that the forecast generation additions are transmission-connected for modelling purposes. It is possible, however, that generation additions, especially small-scale solar, smaller simple-cycle and cogeneration, may connect at the distribution level. These are often referred to as Distributed Energy Resources (DER), and include generation and other resources which are connected to the distribution network within the province. The location of DER additions will impact the resulting power flows; however, given their current small volumes, the impacts to the overall system are limited.

This scenario also includes a High Cogeneration Sensitivity in order to test the impact of increasing the amount of cogeneration capacity at oilsands sites above levels assumed in the Reference Case. An industrial plant's infrastructure and steam needs, natural gas prices, carbon prices and sustainability objectives impact the decision to develop cogeneration. Corporate positions and assessments of these drivers by oilsands operators could lead to incremental development of cogeneration above the levels assumed in the Reference Case. Considering these drivers, the High Cogeneration Sensitivity contains a larger amount of cogeneration development while the rest of the variables in the Reference Case remain constant.

### 4.2.1 2019 LTO Generation Forecasting Methodology

A key purpose of the LTO generation forecast is to inform long-term transmission planning. As such, the generation forecast is premised on sufficient generation capacity being developed to reliably meet demand. With generation in Alberta being developed through competitive market forces, the LTO generation forecast is an assessment of what the competitive market would develop, taking into account the resources available and impacts of costs and policies on investment decisions.

The 2019 LTO itself is not an assessment of the feasibility of the market's ability to deliver the forecasted generation; rather it informs the level of generation that is expected to be required in the long term to reliably meet demand. In considering what generation is likely to develop, the AESO reviews the characteristics of generation technologies including costs, operating characteristics, resource availability, and market behaviour. Each generation technology has different considerations and drivers, which developers take into account when making investment decisions.

Existing coal units have the option to switch from using coal as the main fuel to using natural gas. Switching to natural gas could be in the form of full conversions, the use of co-firing, or repowering. Combined-cycle and simple-cycle units provide reliable baseload, flexible mid-merit, and peaking capacity. The technology is mature, has locational flexibility, relatively low GHG emissions, and good economics. Cogeneration growth is related to increases in industrial activities as there is a need for both heat and energy. Wind and solar facilities provide emission-free intermittent generation with no fuel costs, and development is dependent on capital costs and capturing strong renewable resources. These and other characteristics are all taken into consideration in assessing future developments. Further information on the technologies can be found in Appendix B.

The AESO uses a market simulation tool to assist in determining the likely future generation outlook. This tool is a cost-production model that applies economic principles, dispatch simulation and bidding strategies to model the relationship between supply and demand. It considers key fundamental drivers such as demand, fuel prices and renewable generation profiles. The model incorporates unit characteristics, including start-up costs, minimum up time, minimum down time, and ramp rate to build an economic dispatch. Each technology has specific characteristics, capturing monthly, weekly, and daily variations in technology capability and output. Hourly simulation results are created for the 20-year forecast horizon to support development of the outlook.

In developing the generation forecast, a reserve margin assumption is applied such that the generation forecast results in demand being met reliably. Using a threshold is consistent with the resource adequacy threshold in ISO Rule 202.6 and previous AESO LTO forecasts.

### 4.2.2 Generation Forecasting Assumptions

The 2019 LTO generation forecast implicitly assumes the market will incent or enable the level of generation investment that is required to meet resource adequacy. In addition, it makes assumptions on the pace, timing and feasibility of coal-to-gas conversions. While the Alberta electricity system transitions away from coal-fired generation, the AESO closely monitors and assesses the market to ensure reliability through market participant reporting, announcements, and quarterly long-term adequacy metrics.[13]

***Market Design and Generation Development***

The forecast assumes that market mechanisms will provide adequate support to stimulate the generation investment required to maintain reliability.

***Renewable Generation Development***

The Reference Case assumes that the level of renewable development is based on known policy-supported projects, including Rounds 1, 2 and 3 of the Renewable Electricity Program, Alberta Infrastructure support for solar, and development by market-driven investments. Cost assumptions for wind and solar renewable resources have been made and these assumptions are adjusted in the Diversification Scenario to test an accelerated cost decline for solar resources.

[13] https://www.aeso.ca/market/market-and-system-reporting/long-term-adequacy-metrics/

### *Coal Retirements and Conversions to Gas*

The Reference Case assumes that 5,275 MW of coal-fired capacity will be converted to natural gas-fired generation, beginning in the year 2021. These units are assumed to operate as coal-to-gas (CTG) units for no longer than 10 years beyond their end-of-useful-life. Furthermore, they are assumed to retire in order of vintage and at a rate of no more than two units per year. A detailed retirement and conversion schedule for the Reference Case can be found in Appendix B.

The generation forecast reflects the need for new generation resulting from both the retirement of existing units and an increase in demand. The current coal-fired capacity of 5,723 MW is expected to retire over the 20-year forecast period resulting in a need for considerable new generation. The timing of new generation additions resulting from these retirements is expected in the 2030s as the coal-fired unit lives are extended through conversion to natural gas. Once the converted units begin to retire, the generation build will need to continue at a rate sufficient to replace the retiring capacity.

### *Generation Location Assumptions*

For the purposes of transmission system planning and to fulfill the requirements of the EUA and *Transmission Regulation*, locations are assumed for future generation units. Each technology is assigned to planning regions based on the likelihood of that technology developing in a particular region. Technology location considerations include utilizing existing infrastructure (such as brownfield sites), fuel resources (such as the location of strong wind and solar resources), future planned transmission enhancements, and developer information. Within each region, unit-specific locations are assigned to utilize the existing transmission capability and minimize the need for transmission reinforcements.

Renewable generation additions, primarily wind generation, are split between the AESO's South and Central Planning Regions, with some resources anticipated to develop in the Northwest Planning Region. The actual location of future wind and solar generation, including their development timeframe, will ultimately depend upon developer decisions. The locations of renewable generation stated within the 2019 LTO represent a reasonable assumption, based on where the best potential resources are available (see Appendix B for Alberta's wind and solar resource maps).

Combined-cycle and simple-cycle generation additions are assumed to primarily occur at brownfield coal sites and within regions of previously identified projects. While both brownfield and greenfield sites are viable options and many greenfield sites have been proposed, brownfield sites have been assumed within the LTO due to development advantages, including existing infrastructure and lower development costs compared to greenfield sites.

Cogeneration development is primarily assumed to occur within the established oilsands production areas of Fort McMurray and Cold Lake. In addition, cogeneration locations are assigned to regions with petrochemical growth in areas such as Fort Saskatchewan. This assumption is aligned with the Reference Case load forecast.

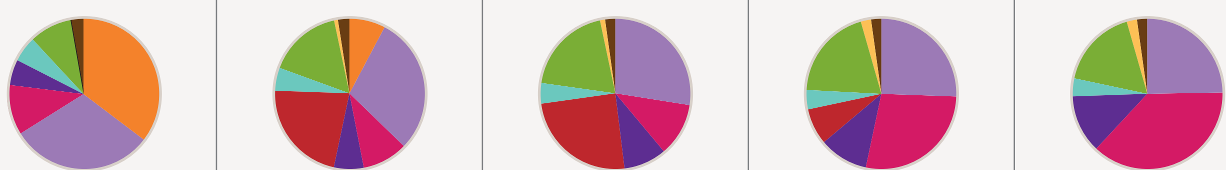
### 4.2.3 Reference Case Generation Results

A forecast of installed generation capacity was developed based on the 2019 LTO assumptions and methodology. In total 13 GW of new generation capacity is forecast to be added by 2039. Coal-fired generation is converted to natural gas, and eventually replaced with new efficient combined-cycle and simple-cycle generation. Renewable development occurs in the near term from REP Rounds 1, 2, and 3, and develops afterwards driven by assumed market-based investment. By 2030, approximately 19 per cent of energy is served by renewables and 81 per cent is served by natural gas. This is higher than the current production from renewables, which is approximately 10 per cent of gross generation. These results indicate some continued growth in renewables without a government-driven procurement mandate, and an increase in natural gas-fired generation leading to the continued convergence between the power and natural gas markets.

Additional details on the Reference Case Generation Scenario, including regional data, can be found within the 2019 LTO data file available at *www.aeso.ca/grid/forecasting.*

**FIGURE 7: Reference Case Generation Scenario Capacity**

| | Existing<br>AIL peak: 11,471 MW | | 2024<br>AIL peak: 12,703 MW | | 2030<br>AIL peak: 13,319 MW | | 2034<br>AIL peak: 13,806 MW | | 2039<br>AIL peak: 14,274 MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| Coal-fired | 36% | 5,723 | 8% | 1,421 | 0% | 0 | 0% | 0 | 0% | 0 |
| Cogeneration | 31% | 4,937 | 30% | 5,319 | 28% | 5,499 | 26% | 5,589 | 25% | 5,679 |
| Combined-cycle | 11% | 1,748 | 10% | 1,748 | 11% | 2,227 | 28% | 6,059 | 37% | 8,454 |
| Simple-cycle | 6% | 921 | 6% | 1,138 | 9% | 1,835 | 11% | 2,300 | 13% | 2,903 |
| Coal-to-gas | 0% | 0 | 22% | 4,009 | 25% | 4,890 | 8% | 1,729 | 0% | 0 |
| Hydro | 6% | 894 | 5% | 894 | 5% | 894 | 4% | 894 | 4% | 894 |
| Wind | 9% | 1,445 | 16% | 2,904 | 19% | 3,854 | 20% | 4,272 | 17% | 3,931 |
| Solar | 0% | 15 | 1% | 131 | 1% | 231 | 2% | 481 | 2% | 481 |
| Other | 3% | 423 | 2% | 423 | 2% | 423 | 2% | 473 | 2% | 473 |
| Total capacity | | 16,106 MW | | 17,987 MW | | 19,853 MW | | 21,797 MW | | 22,815 MW |



### 4.2.4 Generation Forecast Sensitivity

***High Cogeneration Sensitivity Assumptions***

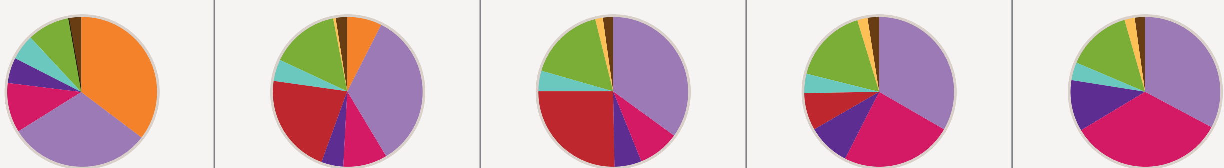
The main assumption of the High Cogeneration Sensitivity is that a higher amount of cogeneration will develop compared to the Reference Case. This sensitivity assumes that some existing oilsands facilities replace existing coke boilers with cogeneration, and that future oilsands development with cogeneration increases the cogeneration unit size. This new cogeneration capacity is incremental; additional oilsands load growth does not occur with the additional capacity. This results in cogeneration additions that are similar to the High Growth Scenario, although load is the same as the Reference Case load.

### *High Cogeneration Sensitivity Results*

In comparison with the Reference Case, the High Cogeneration Sensitivity results in additional cogeneration development which defers and displaces both renewable and gas-fired capacity. After the final REP projects are in service, wind additions are lower compared with the Reference Case as increased cogeneration reduces the expected profitability of wind because of the incremental price-taking baseload energy. Additionally, combined-cycle and simple-cycle are reduced as the need for dispatchable gas-fired capacity is reduced and deferred to later in the forecast.

**FIGURE 8: High Cogeneration Sensitivity Capacity**

| | Existing | | 2024 | | 2030 | | 2034 | | 2039 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | AIL peak: 11,471 MW | | AIL peak: 12,703 MW | | AIL peak: 13,319 MW | | AIL peak: 13,806 MW | | AIL peak: 14,274 MW | |

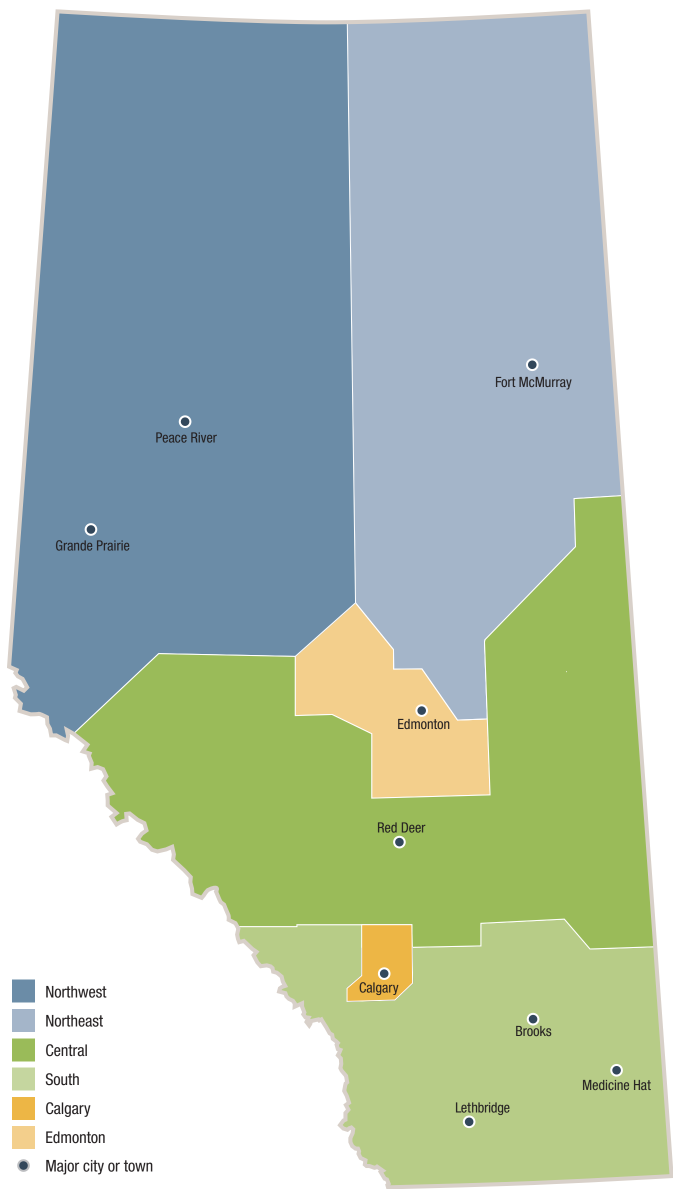


| | Existing % | MW | 2024 % | MW | 2030 % | MW | 2034 % | MW | 2039 % | MW |
|---|---|---|---|---|---|---|---|---|---|---|
| Coal-fired | **36%** | 5,723 | **8%** | 1,421 | **0%** | 0 | **0%** | 0 | **0%** | 0 |
| Cogeneration | **31%** | 4,937 | **34%** | 6,359 | **35%** | 6,809 | **34%** | 7,124 | **33%** | 7,304 |
| Combined-cycle | **11%** | 1,748 | **9%** | 1,748 | **9%** | 1,748 | **24%** | 5,101 | **34%** | 7,496 |
| Simple-cycle | **6%** | 921 | **5%** | 905 | **6%** | 1,138 | **9%** | 1,928 | **11%** | 2,438 |
| Coal-to-gas | **0%** | 0 | **21%** | 4,009 | **25%** | 4,890 | **8%** | 1,729 | **0%** | 0 |
| Hydro | **6%** | 894 | **5%** | 894 | **5%** | 894 | **4%** | 894 | **4%** | 894 |
| Wind | **9%** | 1,445 | **15%** | 2,804 | **16%** | 3,204 | **16%** | 3,472 | **14%** | 3,131 |
| Solar | **0%** | 15 | **1%** | 131 | **2%** | 331 | **2%** | 481 | **2%** | 481 |
| Other | **3%** | 423 | **2%** | 423 | **2%** | 423 | **2%** | 473 | **2%** | 473 |
| **Total capacity** | | **16,106 MW** | | **18,694 MW** | | **19,437 MW** | | **21,202 MW** | | **22,217 MW** |

# 5.0 Regional outlooks

The 2019 LTO is an input to AESO transmission planning and examines the features of each specific AESO Planning Region as well as key drivers affecting load and generation within those regions. Assessing these elements by region assists the AESO in understanding the geographical impacts associated with forecast load and generation. The forecast results outlined in this section are broken out by region and based on the Reference Case forecast and its assumptions. A data file outlining region-specific load and generation information can be found at *www.aeso.ca/grid/forecasting*.

Each Planning Region section includes a subsection regarding risk. The term "risk" applies specifically to the Reference Case results and potential uncertainty due to identified load and generation changes within the region. Many of these uncertainties are evaluated in the LTO scenarios.

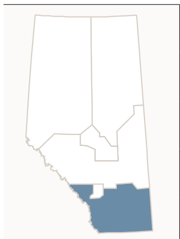


## 5.1 SOUTH PLANNING REGION

### Overview and Forecast

The South Planning Region encompasses southern Alberta and includes Lethbridge, High River, Brooks, and Medicine Hat. It contains approximately 12 per cent of the province's population. This region is generally summer-peaking with higher air conditioning use and seasonal irrigation loads.

**TABLE 1: South Planning Region**



| | |
|---|---|
| 2018 Average Load (MW) | 1,088 |
| 2018 Summer Peak (MW) | 1,481 |
| 2018/2019 Winter Peak (MW) | 1,306 |
| Population (000s) | 480 |
| Area (000km$^2$) | 91 |

### Load

The South Planning Region represents about 11 per cent of Alberta Internal Load (AIL), and contains the majority of provincial farm demand and some industrial load including pipelines, manufacturing, and natural gas processing.

Over the past 10 years, summer peak load has grown by an average annual rate of 1 per cent. Under the Reference Case, the region's summer peak is expected to grow at a rate of 0.1 per cent annually until 2039 due to limited economic growth, a new cannabis facility expected to come online in Medicine Hat, and adoption of electric vehicles (EV) in urban centres.

### Generation

The South Planning Region currently contains approximately 2,974 MW of generation capacity. Wind generation comprises the largest portion at 1,184 MW followed by coal-fired at 790 MW. The region also contains hydro, solar, and cogeneration. In the near term, approximately 1,100 MW of new wind generation is expected to come online from projects successful in REP Rounds 1, 2, and 3.

The region has shown large growth in generation development over the last 10 years with a net growth of 769 MW of capacity. Of this, there was a net increase of 621 MW from wind generation.

The South Planning Region has many opportunities for development from conventional gas-fired generation and renewable energy sources. An assessment of wind and solar resource potential commissioned by the AESO re-confirmed that this region has some of the best wind and solar resources in the province. This is consistent with generation connection applications to the AESO, which show large amounts of wind and solar projects in the region.

The forecast for the South Planning Region anticipates growth in gas-fired generation and renewables along with a decrease in coal-fired generation. Coal-fired capacity is expected to first convert to natural gas and then be replaced with combined-cycle. Renewables are expected to continue to grow, with over 2,100 MW of renewables developing over the 20-year forecast. Energy storage projects of 50 MW are included in the forecast for this region.

**TABLE 2: South Region Load and Generation Capacity Forecast**

| | Existing 2018 (MW) | 2024 (MW) | 2030 (MW) | 2034 (MW) | 2039 (MW) |
|---|---|---|---|---|---|
| Region Peak Load | 1,481 | 1,499 | 1,511 | 1,507 | 1,511 |
| Coal-fired / Coal-to-gas | 790 | 790 | 790 | 0 | 0 |
| Cogeneration | 95 | 95 | 95 | 95 | 95 |
| Combined-cycle | 375 | 375 | 375 | 854 | 854 |
| Simple-cycle | 64 | 110 | 110 | 203 | 389 |
| Hydroelectric | 409 | 409 | 409 | 409 | 409 |
| Wind | 1,184 | 2,395 | 3,045 | 3,263 | 2,922 |
| Solar* | 15 | 131 | 231 | 431 | 431 |
| Other | 42 | 42 | 42 | 92 | 92 |
| Total Generation Capacity | 2,974 | 4,347 | 5,097 | 5,347 | 5,192 |

**This figure does not include rooftop solar which is taken into account within the load forecast*

### Risks to Forecast

The main risks to load growth in the South Planning Region are related to electric vehicle adoption, a new cannabis facility, approval of major export pipelines and energy efficiency gains. Higher or lower electric vehicle adoption and energy efficiency gains could lead to higher or lower growth compared to the Reference Case. There is also some risk associated with the uncertainty of the load at the Medicine Hat cannabis facility. The outlook for the South Planning Region could change depending on the development of export pipelines.

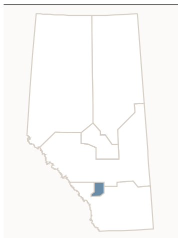
The main generation risks in the South Planning Region are related to renewable development. The amount and pace of development will be dependent on overall market profitability, renewable technology costs and any future amount of renewable support from government policy. While the current LTO does include wind retirements, there is some uncertainty around both the timing of retirement and the potential for wind facilities to be repowered. Because of the drivers behind coal-fired retirements and the drivers for use of natural gas in coal-fired units, the timing of retirements and/or conversion to natural gas is uncertain.

## 5.2 CALGARY PLANNING REGION

### Overview and Forecast

The Calgary Planning Region includes the City of Calgary, Airdrie and the surrounding area, and accounts for about 34 per cent of the province's total population. The region is characterized primarily by urban load, including significant residential and commercial demand, as well as some industrial load. Although this region has been a winter-peaking jurisdiction in past years, the region was summer-peaking in 2018 due to an unusually hot summer in the Calgary area.

**TABLE 3: Calgary Planning Region**



| | |
|---|---|
| 2018 Average Load (MW) | 1,203 |
| 2018 Summer Peak (MW) | 1,795 |
| 2018/2019 Winter Peak (MW) | 1,684 |
| Population (000s) | 1,405 |
| Area (000km$^2$) | 4 |

## Load

The Calgary Planning Region represents 12 per cent of provincial load. Summer peak average annual load growth has been 1 per cent over the past 10 years while winter peak load has decreased by 0.05 per cent. The Reference Case assumes summer and winter peak will grow at 0.3 per cent and 0.6 per cent respectively to 2039 due to population growth and associated commercial and residential demand growth, in addition to electric vehicle adoption. Increased rooftop solar adoption and energy efficiency gains also offset load growth.

## Generation

The Calgary Planning Region contains 1,456 MW of generation capacity. This capacity is all gas-fired and includes 144 MW of simple-cycle and 1,300 MW of combined-cycle. The Calgary Planning Region has seen an increase in generation capacity over the last 10 years, mainly from the Shepard Energy Centre.

As the Calgary Planning Region is primarily an urban centre, generation in the region is restricted to those technologies suited for urban development. This typically includes small-scale renewables such as solar and gas-fired generation. The generation forecast for the Calgary Planning Region has only moderate additions of simple-cycle generation.

**TABLE 4: Calgary Region Load and Generation Capacity Forecast**

| | Existing 2018 (MW) | 2024 (MW) | 2030 (MW) | 2034 (MW) | 2039 (MW) |
|---|---|---|---|---|---|
| Region Peak Load | 1,795 | 1,769 | 1,807 | 1,846 | 1,946 |
| Coal-fired / Coal-to-gas | 0 | 0 | 0 | 0 | 0 |
| Cogeneration | 12 | 12 | 12 | 12 | 12 |
| Combined-cycle | 1,300 | 1,300 | 1,300 | 1,300 | 1,300 |
| Simple-cycle | 144 | 190 | 190 | 190 | 190 |
| Hydroelectric | 0 | 0 | 0 | 0 | 0 |
| Wind | 0 | 0 | 0 | 0 | 0 |
| Solar* | 0 | 0 | 0 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 | 0 |
| Total Generation Capacity | 1,456 | 1,502 | 1,502 | 1,502 | 1,502 |

**This figure does not include rooftop solar which is taken into account within the load forecast*

### Risks to Forecast

Risk to the Calgary load forecast includes more aggressive EV adoption causing increased load. In addition, increases to rooftop solar adoption beyond what is incorporated in the load forecast would decrease and change load patterns in Calgary by offsetting load at the household and distribution level during solar production. Higher energy efficiency in the Calgary region could limit the level of load growth in the region.

From a generation perspective, the largest risk is related to the development of small distributed generation such as solar and gas-fired generation. There is limited potential for large-scale generation, and with efficiency improvements of smaller generation technologies such as solar and reciprocating engines, some development within the urban areas could occur.

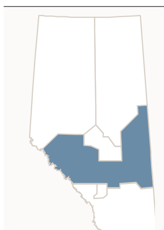
## 5.3 CENTRAL PLANNING REGION

### Overview and Forecast

The Central Planning Region spans the province east–west between the borders of British Columbia and Saskatchewan, and north–south between Cold Lake and Calgary. Its major population centres are the cities of Red Deer and Lloydminster. The region represents about 11 per cent of Alberta's population, primarily concentrated in the Red Deer area.

The Red Deer area contains notable amounts of manufacturing, and there is significant oilsands development in the Cold Lake area. The Central Planning Region also features a considerable amount of pipelines, particularly in the eastern portion of the region.

**TABLE 5: Central Planning Region**



| | |
|---|---|
| 2018 Average Load (MW) | 1,851 |
| 2018 Summer Peak (MW) | 1,980 |
| 2018/2019 Winter Peak (MW) | 2,116 |
| Population (000s) | 450 |
| Area (000km$^2$) | 146 |

### Load

The Central Planning Region currently represents 19 per cent of Alberta's load. Over the past 10 years, the regional winter peak has grown by an average annual rate of 1.5 per cent. The Reference Case assumes winter peak load will grow by 0.7 per cent annually by 2039 as a result of increasing pipeline load, industrial and oilsands growth, and urban growth in the Red Deer area.

The Central Planning Region contains proposals for major export pipelines. It is presently unknown if and when these pipelines will be approved and built. The Reference Case assumes one will be built over the forecast horizon; however, it is possible that more than one or none at all will be built.

### Generation

The Central Planning Region currently contains 2,635 MW of generation capacity comprised of cogeneration, coal-fired, hydro, and wind. There is 248 MW of generation expected to come online in the near term related to the REP.

Over the past 10 years, the Central Planning Region has seen significant growth in wind power and gas-fired cogeneration capacity. It has seen net generation additions of 592 MW, primarily from wind and cogeneration.

The Central Planning Region has opportunities for generation development from conventional gas-fired generation, cogeneration, and renewable energy sources. An assessment of wind and solar resource potential re-confirmed that this region's eastern portion has some of the best wind and solar resources in the province. This is consistent with generation connection applications to the AESO, which show large amounts of wind and solar projects in the region. Expansions at existing hydro facilities are also possible.

The forecast for the Central Planning Region anticipates growth in gas-fired and renewable generation, as well as a decrease in coal-fired generation. Coal-fired generation in the region is expected to retire or convert to natural gas. Coal-to-gas generation is then expected to be replaced with new combined-cycle generation once it retires. Cogeneration is also expected for the region and renewables are expected to continue to grow, with approximately 700 MW of renewables developing over the 20-year forecast.

**TABLE 6: Central Region Load and Generation Capacity Forecast**

| | Existing 2018 (MW) | 2024 (MW) | 2030 (MW) | 2034 (MW) | 2039 (MW) |
|---|---|---|---|---|---|
| Region Peak Load | 2,116 | 2,398 | 2,516 | 2,565 | 2,669 |
| Coal-fired / Coal-to-gas | 689 | 540 | 0 | 0 | 0 |
| Cogeneration | 1,145 | 1,241 | 1,286 | 1,286 | 1,331 |
| Combined-cycle | 0 | 0 | 0 | 479 | 958 |
| Simple-cycle | 5 | 51 | 330 | 330 | 330 |
| Hydroelectric | 485 | 485 | 485 | 485 | 485 |
| Wind | 261 | 509 | 759 | 909 | 909 |
| Solar* | 0 | 0 | 0 | 50 | 50 |
| Other | 50 | 50 | 50 | 50 | 50 |
| Total Generation Capacity | 2,635 | 2,876 | 2,910 | 3,589 | 4,113 |

**This figure does not include rooftop solar which is taken into account within the load forecast*

## Risks to Forecast

Central Planning Region load risks include overall economic and population growth uncertainty and, in particular, oilsands development. Oilsands is a major driver of load in the Central region, and the rate of growth of this industry will have the largest impact on growth in electricity consumption. Changes to electric vehicle adoption and the cannabis farming industry will impact load growth but to a lesser extent.

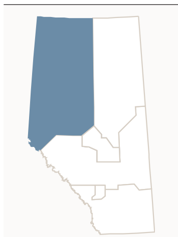
The main risks to generation development in the Central Planning Region are related to renewable and cogeneration development, and existing coal-fired operation. The amount and pace of renewable development will be dependent on overall market profitability, renewable technology costs and any future amount of renewable support from government policy. Cogeneration is tied to industrial development and with uncertainty in oilsands development, the amount of cogeneration also faces uncertainty. With coal-fired generation in the region, the exact timing of retirements and/or conversions is currently uncertain given the potential for change in the drivers behind them.

## 5.4 NORTHWEST PLANNING REGION

### Overview and Forecast

The Northwest Planning Region represents approximately one-third of the province and 5 per cent of the population. The largest population centre is the City of Grande Prairie. Given its low population, residential and commercial electricity demand is relatively low compared to northwest industrial demand, especially when compared to residential and commercial demand in other regions. Some agricultural activity takes place in this region as well.

**TABLE 7: Northwest Planning Region**



| | |
|---|---|
| **2018 Average Load (MW)** | 1,045 |
| **2018 Summer Peak (MW)** | 1,157 |
| **2018/2019 Winter Peak (MW)** | 1,221 |
| **Population (000s)** | 215 |
| **Area (000km$^2$)** | 230 |

### Load

The Northwest Planning Region accounts for approximately 11 per cent of the provincial total, most of which is industrial. Load growth in the Northwest Planning Region over the past 10 years has an average annual winter peak load growth rate of 1 per cent. The Reference Case assumes continued load growth with winter-peak growth of 0.3 per cent to 2039.

### Generation

The Northwest Planning Region currently contains 988 MW of generation capacity. This capacity is primarily gas-fired generation, although there is also coal-fired and biomass capacity. The Northwest Planning Region has seen an increase in gas-fired and biomass generation capacity over the last 10 years with net additions of 233 MW.

There are a variety of resources showing development potential in this region with gas-fired generation being the main expected source. Approximately two-thirds of generation in the region is currently gas-fired (primarily simple-cycle). In addition to gas-fired generation, there is potential for some development of renewables such as wind, biomass and geothermal.

The majority of forecast generation in the Northwest Planning Region is from gas-fired combined-cycle and simple-cycle. Some development of wind resources are anticipated in the future.

**TABLE 8: Northwest Region Load and Generation Capacity Forecast**

| | Existing 2018 (MW) | 2024 (MW) | 2030 (MW) | 2034 (MW) | 2039 (MW) |
|---|---|---|---|---|---|
| Region Peak Load | 1,221 | 1,254 | 1,267 | 1,243 | 1,303 |
| Coal-fired / Coal-to-gas | 144 | 0 | 0 | 0 | 0 |
| Cogeneration | 147 | 162 | 162 | 162 | 162 |
| Combined-cycle | 73 | 73 | 73 | 552 | 552 |
| Simple-cycle | 442 | 535 | 814 | 814 | 766 |
| Hydroelectric | 0 | 0 | 0 | 0 | 0 |
| Wind | 0 | 0 | 50 | 50 | 50 |
| Solar* | 0 | 0 | 0 | 0 | 0 |
| Other | 182 | 182 | 182 | 182 | 182 |
| Total Generation Capacity | 988 | 952 | 1,281 | 1,760 | 1,712 |

**This figure does not include rooftop solar which is taken into account within the load forecast*

### Risks to Forecast

The main source of load growth risk in the Northwest Planning Region relates to unconventional oil and gas development. There are a number of load projects that have applied to the AESO in the Grand Prairie and Grande Cache areas, for example. The timing and ultimate potential of load growth due to unconventional oil and gas development remains uncertain, especially given current projections of low crude oil and natural gas prices. The Northwest Planning Region also has potential for oilsands growth.

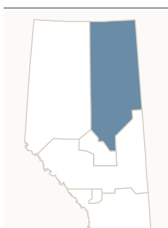
There are a number of generation development risks in the Northwest Planning Region. Uncertainty in this region is related to the development of gas-fired generation. The amount of industrial activity and associated cogeneration could change based on multiple factors that could impact the forecast. Moreover, given the development of some thermal projects in the region, the level of combined-cycle and simple-cycle development could change.

## 5.5 NORTHEAST PLANNING REGION

### Overview and Forecast

The Northeast Planning Region is sparsely populated, containing approximately 3 per cent of the provincial population. Most residents are located in the Fort McMurray area of the Regional Municipality of Wood Buffalo. The economy in this region is driven by the oilsands industry and is directly linked to future oilsands projects. The low population in this planning region results in minimal residential and commercial load.

**TABLE 9: Northeast Planning Region**



| | |
|---|---|
| 2018 Average Load (MW) | 2,779 |
| 2018 Summer Peak (MW) | 3,024 |
| 2018/2019 Winter Peak (MW) | 3,309 |
| Population (000s) | 137 |
| Area (000km²) | 169 |

### Load

Despite the low population, the Northeast Planning Region contains about 28 per cent of AIL. Over the past 10 years, load growth has been the strongest of any region with an average annual winter peak growth rate of 6 per cent annually as oilsands projects developed and ramped up production. In the near term, projects currently under construction are expected to contribute to load growth. The Reference Case forecasts average annual winter-peak load growth at a rate of 2 per cent to 2039.

Over time, smaller expansions to existing oilsands sites are expected to develop, and increased related pipeline load is also expected to contribute to load growth. Due to the ramp up of oilsands and other industrial projects, the Northeast Planning Region is Alberta's fastest growing planning region in terms of load with almost 1,171 MW of new load expected by 2039.

### Generation

The region currently has 3,638 MW of generation, mostly in the form of cogeneration. In addition, there has been some development of biomass. Over the last 10 years, the Northeast Planning Region has seen the largest amount of generation capacity growth compared with any other planning region. Most generation development in the region has come from industrial activity and cogeneration related to the oilsands industry.

Potential development in this region is primarily expected to be gas-fired generation in the form of cogeneration, simple-cycle and combined-cycle. Most of the connection projects in the region that have applied to the AESO are currently gas-fired generation. Some areas within the planning region could see renewable development from wind.

The forecast for this region includes over 1,200 MW of gas-fired cogeneration, combined-cycle, and simple-cycle. In the long term, a small amount of wind generation is also expected.

**TABLE 10: Northeast Region Load and Generation Capacity Forecast**

| | Existing 2018 (MW) | 2024 (MW) | 2030 (MW) | 2034 (MW) | 2039 (MW) |
|---|---|---|---|---|---|
| Region Peak Load | 3,309 | 3,582 | 3,947 | 4,247 | 4,422 |
| Coal-fired / Coal-to-gas | 0 | 0 | 0 | 0 | 0 |
| Cogeneration | 3,489 | 3,760 | 3,895 | 3,985 | 4,030 |
| Combined-cycle | 0 | 0 | 0 | 0 | 479 |
| Simple-cycle | 0 | 0 | 139 | 139 | 186 |
| Hydroelectric | 0 | 0 | 0 | 0 | 0 |
| Wind | 0 | 0 | 0 | 50 | 50 |
| Solar* | 0 | 0 | 0 | 0 | 0 |
| Other | 149 | 149 | 149 | 149 | 149 |
| Total Generation Capacity | 3,638 | 3,909 | 4,183 | 4,323 | 4,894 |

**This figure does not include rooftop solar which is taken into account within the load forecast*

### Risks to Forecast

Since the bulk of Northeast Planning Region load growth is related to oilsands development, the main source of load forecast risk is directly related to the pace and magnitude of oilsands development, which could vary depending on the future attractiveness of oilsands development. Factors which affect this attractiveness include future crude oil prices, project costs, export infrastructure, policy shifts and support, and financing/capital availability. This region contains the Fort Saskatchewan area, which has potential for additional industrial development that could affect regional load.

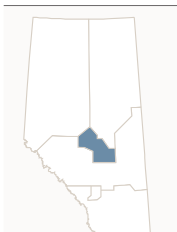
Similar to the load forecast, the amount of cogeneration that develops depends on the pace and scale of oilsands development. In addition, cogeneration may develop to replace aging boilers at existing facilities. As such, the largest risk for the region is around the amount and timing of cogeneration.

## 5.6 EDMONTON PLANNING REGION

### Overview and Forecast

The Edmonton Planning Region contains the City of Edmonton, St. Albert, Sherwood Park, Spruce Grove, Leduc and the Wabamun Lake area. It represents approximately 34 per cent of Alberta's population. This region contains the most significant amount of provincial generation capacity, specifically in the Wabamun area.

**TABLE 11: Edmonton Planning Region**



| | |
|---|---|
| 2018 Average Load (MW) | 1,585 |
| 2018 Summer Peak (MW) | 2,140 |
| 2018/2019 Winter Peak (MW) | 2,104 |
| Population (000s) | 1,407 |
| Area (000km$^2$) | 22 |

### Load

This region represents 16 per cent of Alberta's load, and over the past 10 years has seen its summer peak grow at an average annual rate of 1 per cent, and its winter peak grow at 0.4 per cent. Load in the Edmonton region consists of residential and commercial load as well as oil refining, manufacturing and pipeline load.

By 2039 winter-peak load is forecast to grow at 0.6 per cent annually. The bulk of this growth is expected in the City of Edmonton area, driven primarily by residential, commercial and industrial development. Electric vehicle adoption and cannabis operations are also expected to contribute to future load growth, with rooftop solar adoption and energy efficiency offsetting some of that growth.

### Generation

The Edmonton Planning Region contains 4,399 MW of generation capacity. This capacity is a mix of coal-fired and gas-fired generation, with coal-fired generation contributing 4,100 MW.

The Edmonton Planning Region has remained constant in terms of net generation capacity over the last 10 years. The 463 MW Keephills 3 unit came in service in 2011, while the retirements of Sundance 1 and 2 have offset that capacity. Additionally, many of the coal-fired units have upgraded their facilities to gain incremental capacity.

The Edmonton Planning Region contains coal-fired units and many large generation projects are proposed for the region. Additionally, the region contains a large urban centre, which could see development of technologies suited for development there. In addition to the potential for large-scale generation, there is potential for gas-fired generation and small-scale renewables such as solar.

The generation forecast for the Edmonton Planning Region sees a large reduction in coal-fired generation as it converts to natural gas. In the long term, it is expected to see large combined-cycle and simple-cycle generation to meet retirements and load growth. Overall, the forecast for the region has a net increase of 1,000 MW in total installed generation capacity.

**TABLE 12: Edmonton Region Load and Generation Capacity Forecast**

| | Existing 2018 (MW) | 2024 (MW) | 2030 (MW) | 2034 (MW) | 2039 (MW) |
|---|---|---|---|---|---|
| **Region Peak Load** | 2,140 | 2,326 | 2,407 | 2,471 | 2,553 |
| **Coal-fired / Coal-to-gas** | 4,100 | 4,100 | 4,100 | 1,729 | 0 |
| **Cogeneration** | 49 | 49 | 49 | 49 | 49 |
| **Combined-cycle** | 0 | 0 | 479 | 2,874 | 4,311 |
| **Simple-cycle** | 250 | 250 | 250 | 622 | 1,040 |
| **Hydroelectric** | 0 | 0 | 0 | 0 | 0 |
| **Wind** | 0 | 0 | 0 | 0 | 0 |
| **Solar*** | 0 | 0 | 0 | 0 | 0 |
| **Other** | 0 | 0 | 0 | 0 | 0 |
| **Total Generation Capacity** | 4,399 | 4,399 | 4,878 | 5,274 | 5,400 |

**This figure does not include rooftop solar which is taken into account within the load forecast*

## Risks to Forecast

Increases in industrial load beyond what is forecast in the Reference Case would increase load growth in Edmonton. Similar to the Calgary region, changes in EV and rooftop solar adoption beyond what is incorporated in the load forecast as well as energy efficiency gains are risks to the load forecast. Material changes in any of these could impact the outlook for future load growth in the Edmonton region.

From a generation perspective, the largest risk is related to the timing and extent of switching coal-fired units to gas-fired units, and the timing of retirements and replacement of this capacity as it is subject to change based on decisions made by owners and developers. Also, within the urban areas, there is limited potential for large-scale generation, and with technology improvements in smaller distributed generation technologies, smaller generation could develop. Smaller generation includes both gas-fired generation and renewables such as solar.

# 6.0 2019 LTO scenarios, assumptions and results

The 2019 LTO is built upon a Reference Case which includes a High Cogeneration Generation Sensitivity, along with three load scenarios and four generation scenarios. These scenarios enable the AESO to quantify and assess the outcomes of a variety of potential future impacts. The AESO considers all scenarios and uses its Reference Case as its primary corporate forecast, or base case. If other scenarios become more likely, the AESO may adopt one as its Reference Case in future plans.

The AESO continually reviews its forecasts as economic, policy and other influential drivers evolve. In order to align the latest information with its studied forecasts, the AESO will consider alternate load and/or generation assumptions when appropriate. Further, the AESO will provide updates to align with the latest information when needed.

This section includes all of the scenarios presented in the 2019 LTO. A brief summary of both generation and load, including the assumptions and results for each scenario, is detailed here.

## 6.1 ALTERNATE RENEWABLE POLICY SCENARIO

Considering the same load growth as the Reference Case, the Alternate Renewable Policy Scenario provides an outlook for the Alberta generation fleet if it were driven by a renewable energy target or policy that supports greater renewable development. The drivers of this scenario include strong government support in order to achieve a goal of 30 per cent of energy produced in Alberta from renewable sources by the year 2030 and a higher carbon price of $30/tonne. Other assumptions align with the Reference Case.

### 6.1.1 Alternate Renewable Policy Scenario Load Assumptions

The Alternate Renewable Policy Scenario assumes the same load growth as the Reference Case.

### 6.1.2 Alternate Renewable Policy Scenario Generation Assumptions

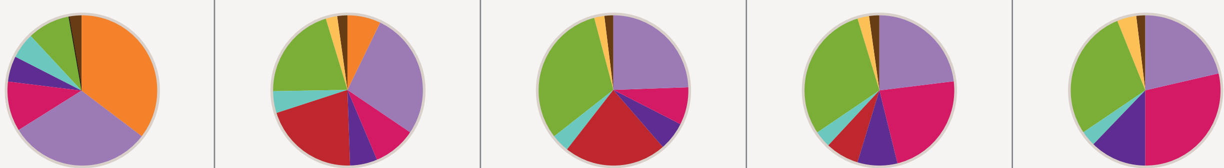
The key assumption in the Alternate Renewable Policy Scenario is an increase in the amount of renewables compared to the Reference Case. Assumed government support for renewables continues in line with observed renewable portfolio standards common in other jurisdictions. The additions are weighted to the lowest-cost renewable technology based on current estimates. As such, the main assumption is that wind capacity grows by approximately 5,900 MW over the 20-year forecast period.

### 6.1.3 Alternate Renewable Policy Scenario Generation Results

The Alternate Renewable Policy Scenario has a large amount of renewable generation compared to the Reference Case. Over 5,900 MW of wind and 1,000 MW of solar capacity are added to the fleet at the end of the forecast period. Wind generation capacity is 28 per cent of the generation mix in 2039. This results in more simple-cycle additions, along with less combined-cycle generation capacity.

**FIGURE 9: Alternate Renewable Policy Scenario – Generation Capacity**

| | Existing | | 2024 | | 2030 | | 2034 | | 2039 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | AIL peak: 11,471 MW | | AIL peak: 12,703 MW | | AIL peak: 13,319 MW | | AIL peak: 13,806 MW | | AIL peak: 14,274 MW | |



| | Existing % | Existing MW | 2024 % | 2024 MW | 2030 % | 2030 MW | 2034 % | 2034 MW | 2039 % | 2039 MW |
|---|---|---|---|---|---|---|---|---|---|---|
| Coal-fired | 36% | 5,723 | 7% | 1,421 | 0% | 0 | 0% | 0 | 0% | 0 |
| Cogeneration | 31% | 4,937 | 27% | 5,319 | 25% | 5,499 | 23% | 5,589 | 22% | 5,679 |
| Combined-cycle | 11% | 1,748 | 9% | 1,748 | 8% | 1,748 | 23% | 5,580 | 29% | 7,496 |
| Simple-cycle | 6% | 921 | 6% | 1,138 | 6% | 1,370 | 9% | 2,114 | 12% | 3,182 |
| Coal-to-gas | 0% | 0 | 21% | 4,009 | 22% | 4,890 | 7% | 1,729 | 0% | 0 |
| Hydro | 6% | 894 | 5% | 894 | 4% | 894 | 4% | 894 | 3% | 894 |
| Wind | 9% | 1,445 | 21% | 4,004 | 31% | 7,004 | 30% | 7,172 | 28% | 7,431 |
| Solar | 0% | 15 | 2% | 461 | 2% | 461 | 3% | 661 | 4% | 1,061 |
| Other | 3% | 423 | 2% | 423 | 2% | 423 | 2% | 473 | 2% | 473 |
| Total capacity | | 16,106 MW | | 19,417 MW | | 22,289 MW | | 24,212 MW | | 26,216 MW |

## 6.2 HIGH GROWTH SCENARIO

The High Growth Scenario assumes that Alberta's economic growth is stronger, resulting in the addition of a significant number of new load projects. Moreover, higher oil prices and new pipelines constructed during the forecast period allow for larger oilsands expansions. Higher load growth also arises from higher adoption rates of electric demand sources such as electric vehicles, driven by lower battery prices, economies of scale, and federal incentives.

In the High Growth Scenario, generation capacity increases to match the higher load outlook. With higher oilsands development and load growth, cogeneration additions experience significant growth and displace other technologies such as economic-driven wind generation. The majority of the other generation assumptions are the same as the Reference Case.

### 6.2.1 High Growth Scenario Load Assumptions

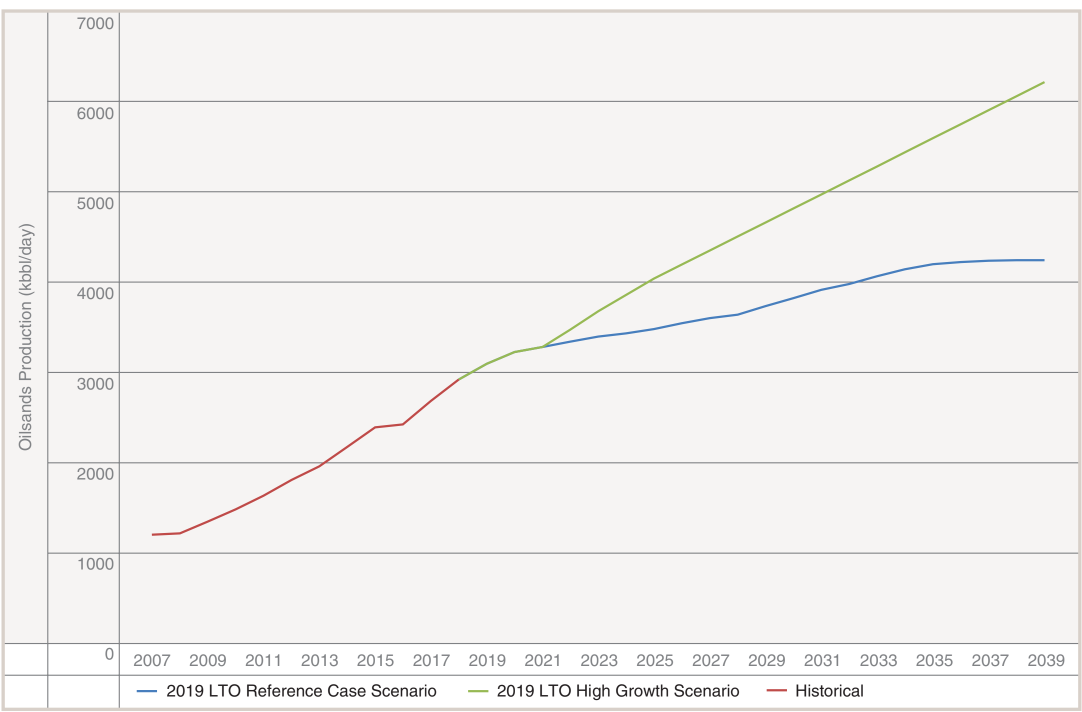
The High Growth Scenario allows the AESO to test a situation in which oil export capacity is increased, and crude oil prices rebound with long-term expectations for strong economic and load growth. Energy efficiency assumptions remain the same as the assumptions used in the Reference Case.

The High Growth Scenario assumes a robust economic recovery beginning in 2021 led by the development of major oilsands projects, many of which were previously postponed or deferred. The increase in oilsands activity leads to higher growth in Calgary and Edmonton as well as increased load growth in northwest Alberta.

In this scenario the increased load in northwest Alberta is a result of increased condensate demand. Oilsands projects use condensate for transportation of bitumen. The increase in demand for condensate and other natural gas liquids results in increased drilling and completion activity in the northwest, increasing load in that part of the province.

The Trans Mountain Expansion and Keystone XL pipeline projects are assumed to be completed over the next five years. Pipeline projects similar to Energy East and Northern Gateway are assumed to be completed over the next 10 to 20 years. This level of pipeline capacity would enable the oilsands to expand and substantially drive higher load in this scenario. Figure 10 shows the oilsands forecast for the High Growth Scenario. The historic oilsands production data is sourced from the Alberta government's Economic Dashboard.[14]

**FIGURE 10: High Growth Scenario – Oilsands Forecast**




The assumed real GDP forecast for the High Growth Scenario is 3.3 per cent CAGR from 2018 to 2039 compared to the Reference Case assumption of 1.9 per cent CAGR over the same time period.

[14] https://economicdashboard.alberta.ca/OilProduction#type

In the High Growth Scenario, higher load growth also arises from electrification and higher adoption of electric vehicles in the province due to incentives and rapidly declining battery costs. Rooftop solar assumptions remain the same as the assumptions used in the Reference Case due to similar assumed economics.

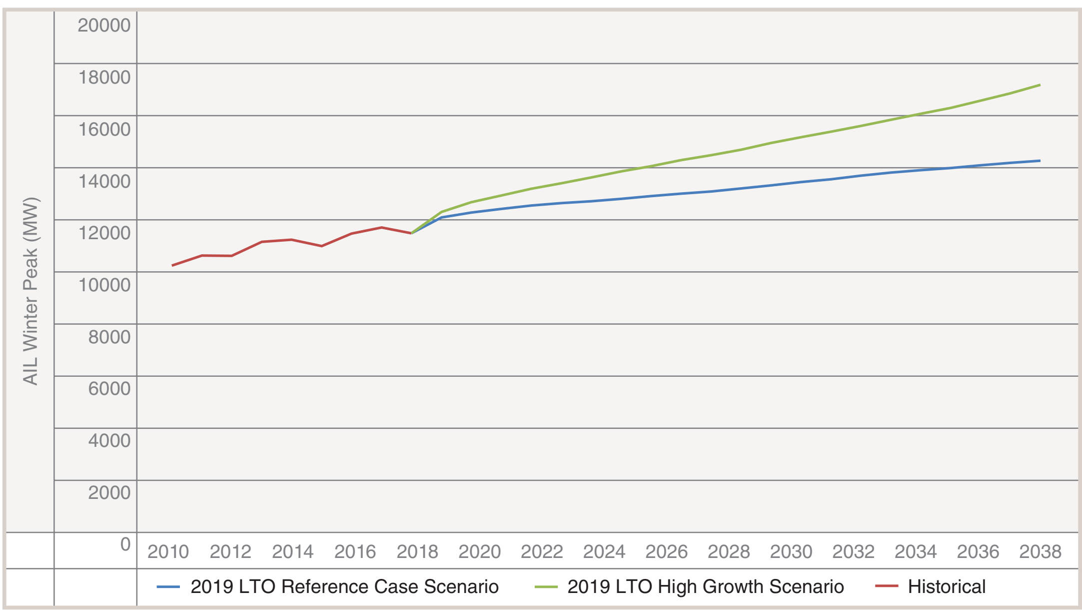
### 6.2.2 High Growth Scenario Load Methodology

The methodology to create the load forecast for the High Growth Scenario is similar to that of the Reference Case.

### 6.2.3 High Growth Scenario Load Results

This scenario has a compound annual peak load growth of 1.8 per cent to 2039. The High Growth Scenario has the highest long-run load growth rate of all the scenarios with a compound annual growth rate of 1.9 per cent to 2029, and 1.8 per cent to 2039. In comparison, the Reference Case grows by 0.9 per cent from 2018 to 2039.

**FIGURE 11: High Growth Scenario – Winter Peak Load**




### 6.2.4 High Growth Scenario Generation Assumptions

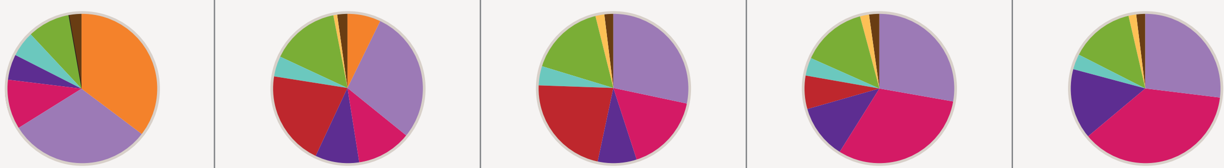
The majority of assumptions in this scenario remain the same as the Reference Case. The key difference is that with higher load growth driven by oil, natural gas and petrochemical activities, corresponding cogeneration levels are also higher. With increased growth in the oilsands, the amount of assumed cogeneration growth is increased such that there is 2,362 MW of cogeneration development.

### 6.2.5 High Growth Scenario Generation Results

The primary impact of increased load growth is that more firm gas-fired generation is expected to develop. Both combined-cycle and simple-cycle units are added earlier in the forecast. There is an increase in the amount of cogeneration compared with the Reference Case. The level of renewable additions is assumed to be marginally lower than the Reference Case.

**FIGURE 12: High Growth Scenario – Generation Capacity**

| | Existing<br>AIL peak: 11,471 MW | | 2024<br>AIL peak: 13,621 MW | | 2030<br>AIL peak: 14,949 MW | | 2034<br>AIL peak: 15,846 MW | | 2039<br>AIL peak: 17,193 MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | % | MW | % | MW | % | MW | % | MW | % | MW |
| Coal-fired | **36%** | 5,723 | **7%** | 1,421 | **0%** | 0 | **0%** | 0 | **0%** | 0 |
| Cogeneration | **31%** | 4,937 | **29%** | 5,589 | **28%** | 6,264 | **28%** | 6,759 | **27%** | 7,299 |
| Combined-cycle | **11%** | 1,748 | **11%** | 2,227 | **17%** | 3,664 | **31%** | 7,496 | **37%** | 9,891 |
| Simple-cycle | **6%** | 921 | **9%** | 1,835 | **8%** | 1,835 | **12%** | 2,858 | **15%** | 4,112 |
| Coal-to-gas | **0%** | 0 | **21%** | 4,009 | **22%** | 4,890 | **7%** | 1,729 | **0%** | 0 |
| Hydro | **6%** | 894 | **5%** | 894 | **4%** | 894 | **4%** | 894 | **3%** | 894 |
| Wind | **9%** | 1,445 | **15%** | 2,904 | **16%** | 3,604 | **14%** | 3,472 | **14%** | 3,731 |
| Solar | **0%** | 15 | **1%** | 131 | **2%** | 431 | **2%** | 481 | **2%** | 481 |
| Other | **3%** | 423 | **2%** | 423 | **2%** | 423 | **2%** | 473 | **2%** | 473 |
| **Total capacity** | | **16,106 MW** | | **19,433 MW** | | **22,005 MW** | | **24,162 MW** | | **26,881 MW** |



## 6.3 LOW GROWTH SCENARIO

The energy sector is the driving force of the Alberta economy, and the greatest risk to growth in electricity demand over the forecast period is a considerable slowdown in oilsands development. The impetus behind a slowdown in oilsands production – whether it be from a collapse in oil prices, a change in policy, or other factors – is less important from a long-term forecasting perspective than examining the resulting effects of such a slowdown, including secondary and tertiary impacts on the rest of the Alberta economy.

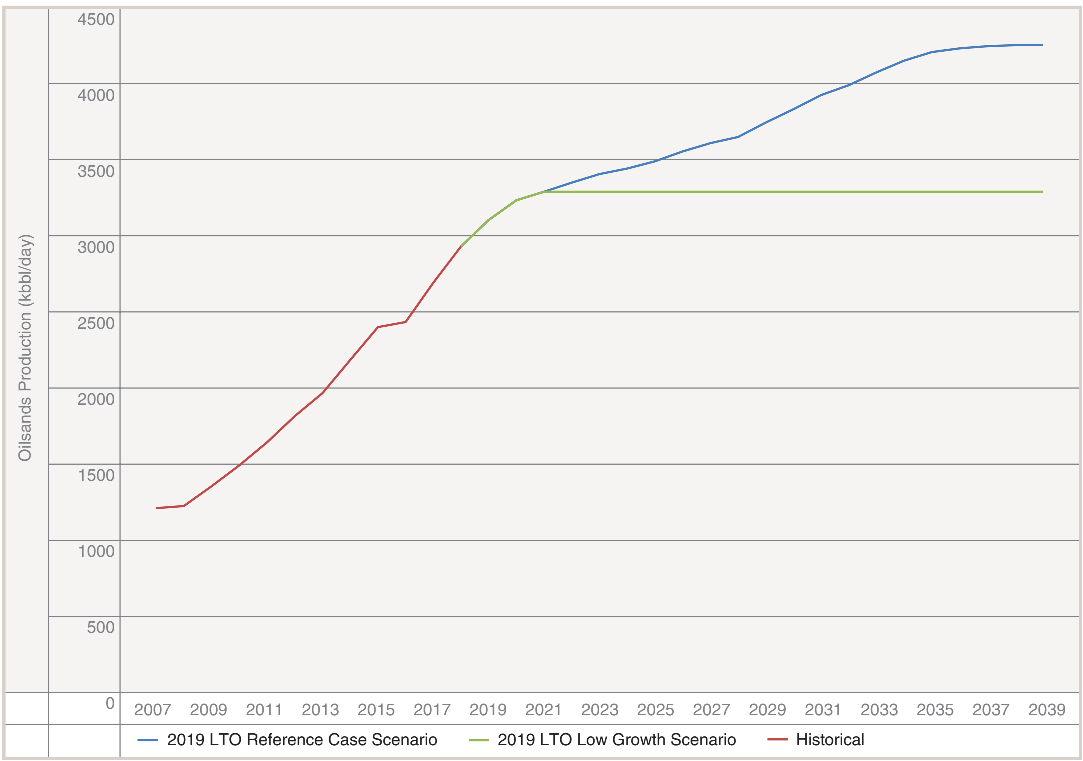
The Low Growth Scenario tests the impacts of lower load growth corresponding to significantly reduced oilsands and economic growth in Alberta. It assumes that Alberta's reduced load growth is due to low economic growth and other factors such as energy efficiency gains, onsite generation development, and an increased adoption of PV rooftop solar. Economic growth in this scenario originates from non-electricity intensive industries. Due to the significant reduction of investment in oilsands development and the corresponding economic impacts, load throughout the province grows considerably slower than in the Reference Case. Rooftop solar capacity increases significantly due to declining technology costs, social influences, and incentives to install solar, while the generation side experiences a decline in the build of large-scale bulk solar farms.

Due to lower industrial growth in the Low Growth Scenario, the amount of assumed cogeneration is reduced. The generation mix is similar to the Reference Case, with fewer capacity additions including less wind development. No new cogeneration is forecast to develop after 2021, while new generation develops after 2030 to replace generation retirements. To test the impacts of lower load growth in isolation, the majority of the generation assumptions are the same as the Reference Case.

### 6.3.1 Low Growth Scenario Load Assumptions

The Low Growth Scenario assumes existing and under-construction oilsands projects remain operating, but no new projects proceed. Current under-construction projects contribute to a rise in near-term load growth, resulting in a peak load growth rate of 0.9 per cent to the year 2021. Oilsands growth will stay flat after 2021 leading to significantly lower economic growth. Similarly, no further growth in the petrochemicals industry is assumed after 2021. In the Low Growth Scenario, peak AIL grows at 0.2 per cent to 2029 and 0.1 per cent CAGR to 2039. Figure 13 shows the Low Growth Scenario forecast for the oilsands industry in Alberta. The historic oilsands production data is sourced from the Alberta government's Economic Dashboard.[15]

**FIGURE 13: Low Growth Scenario – Oilsands Forecast**




To forecast GDP growth for this scenario, the AESO used the GDP outlook from provinces with lower growth expectations (New Brunswick, Nova Scotia) as a proxy for what Alberta growth would be if the oilsands do not continue to expand. The real GDP growth rate for the Low Growth Scenario is 1.1 per cent CAGR from 2018 to 2039 compared to the Reference Case 1.9 per cent CAGR over the same time period.[16]

Energy efficiency increases as a result of non-electricity intensive industries growing in Alberta instead of the oilsands industry. The economy continues to grow after 2021; however, energy efficiency gains offset any increase in electricity demand. Rooftop solar capacity also increases due to assumed lower solar installation costs and economics.

[15] https://economicdashboard.alberta.ca/OilProduction#type

[16] The Conference Board of Canada. Provincial Outlook Long-Term Economic Forecast: Nova Scotia—2019. Ottawa: The Conference Board of Canada, 2019 https://www.conferenceboard.ca/e-library/abstract.aspx?did=10113

The Conference Board of Canada. Provincial Outlook Long-Term Economic Forecast: New Brunswick—2019. Ottawa: The Conference Board of Canada, 2019 https://www.conferenceboard.ca/e-library/abstract.aspx?did=10114

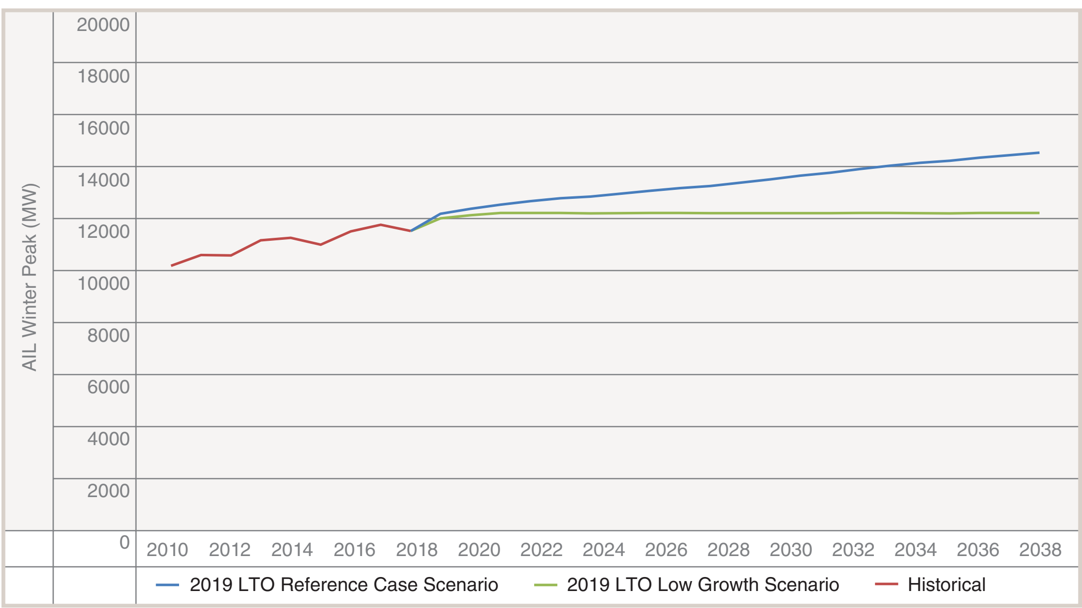
### 6.3.2 Low Growth Scenario Load Methodology

The methodology to create the load forecast in the Low Growth Scenario is similar to that of the Reference Case, as described in Section 4.1.1. The AIL, regions and areas are assessed with the assumed lower economic and oilsands outlooks. Oilsands-focused areas such as Area 25 (Fort McMurray) and Area 28 (Cold Lake) are heavily impacted by the decreased oilsands forecast compared to other parts of the province, as they comprise a large percentage of oilsands load.

### 6.3.3 Low Growth Scenario Load Results

The long-run load growth in the Low Growth Scenario is 0.1 per cent annual growth over 20 years compared to the Reference Case of 0.9 per cent annual growth over 20 years (see Figure 14). As described in the load assumptions section, the decrease in the load outlook compared to the Reference Case is due to a lower oilsands and economic outlook and an increased energy efficiency assumption.

**FIGURE 14: Low Growth Scenario – Winter Peak Load**




### 6.3.4 Low Growth Scenario Generation Assumptions

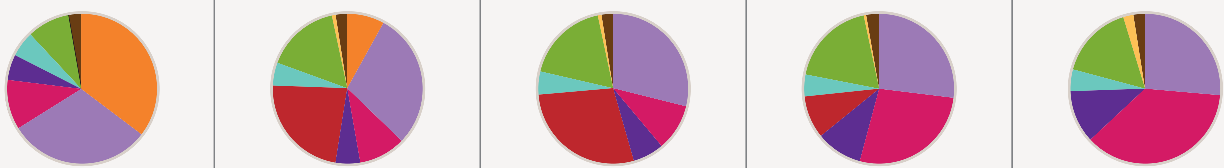
The majority of assumptions in the Low Growth Scenario remain the same as the Reference Case. The key difference is that with lower oilsands and load growth, corresponding cogeneration levels are also lower. With decreased growth in the oilsands, the amount of assumed cogeneration growth is reduced such that 157 MW of new cogeneration develops.

### 6.3.5 Low Growth Scenario Generation Results

Due to lower load growth of this scenario in comparison with the Reference Case, less generation develops over the forecast horizon. The Low Growth Scenario has less overall development from all technologies. Firm gas additions are mostly to replace coal and coal-to-gas retirements; load is not a major driver of additions. Wind projects which have received contracts under the REP are assumed to develop while additional wind development is reduced 50 per cent compared with the Reference Case.

**FIGURE 15: Low Growth Scenario – Generation Capacity**

| | Existing | | 2024 | | 2030 | | 2034 | | 2039 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | AIL peak: 11,471 MW | | AIL peak: 12,100 MW | | AIL peak: 12,111 MW | | AIL peak: 12,116 MW | | AIL peak: 12,116 MW | |



| Type | Existing % | Existing MW | 2024 % | 2024 MW | 2030 % | 2030 MW | 2034 % | 2034 MW | 2039 % | 2039 MW |
|---|---|---|---|---|---|---|---|---|---|---|
| Coal-fired | 36% | 5,723 | 8% | 1,421 | 0% | 0 | 0% | 0 | 0% | 0 |
| Cogeneration | 31% | 4,937 | 29% | 5,094 | 29% | 5,094 | 27% | 5,094 | 27% | 5,094 |
| Combined-cycle | 11% | 1,748 | 10% | 1,748 | 10% | 1,748 | 27% | 5,101 | 37% | 7,017 |
| Simple-cycle | 6% | 921 | 5% | 905 | 7% | 1,138 | 10% | 1,835 | 11% | 2,159 |
| Coal-to-gas | 0% | 0 | 23% | 4,009 | 28% | 4,890 | 9% | 1,729 | 0% | 0 |
| Hydro | 6% | 894 | 5% | 894 | 5% | 894 | 5% | 894 | 5% | 894 |
| Wind | 9% | 1,445 | 16% | 2,804 | 18% | 3,154 | 19% | 3,472 | 16% | 3,131 |
| Solar | 0% | 15 | 1% | 131 | 1% | 131 | 1% | 131 | 2% | 381 |
| Other | 3% | 423 | 2% | 423 | 2% | 423 | 3% | 473 | 2% | 473 |
| Total capacity | | 16,106 MW | | 17,429 MW | | 17,472 MW | | 18,729 MW | | 19,149 MW |

## 6.4 DIVERSIFICATION SCENARIO

The Diversification Scenario assumes that Alberta's economy shifts away from oil and gas and towards other sectors to fuel economic growth. Economic growth in this scenario is moderate; similar to the Reference Case. Drivers for this scenario include an overall culture shift among consumers, economic growth in services, agri-foods, technological innovation, automation, transport electrification, data centres, as well as the cannabis farming industry and technology adoption growth in the province.

The Diversification Scenario allows the AESO, for the first time, to test the impacts of technological change and new industries on both load and generation. In this scenario, load shifts away from the oil and gas industries and regions, and Alberta's economy continues to grow from other industries. While certain assumptions are made around the type of industries that emerge for this scenario, the actual industries that develop could be quite different. Overall, we expect the locations where new industries develop and their associated load growth will be similar regardless of the particular type of industry that develops. Energy diversification leading to increased petrochemical growth in the near term occurs due to government incentives.

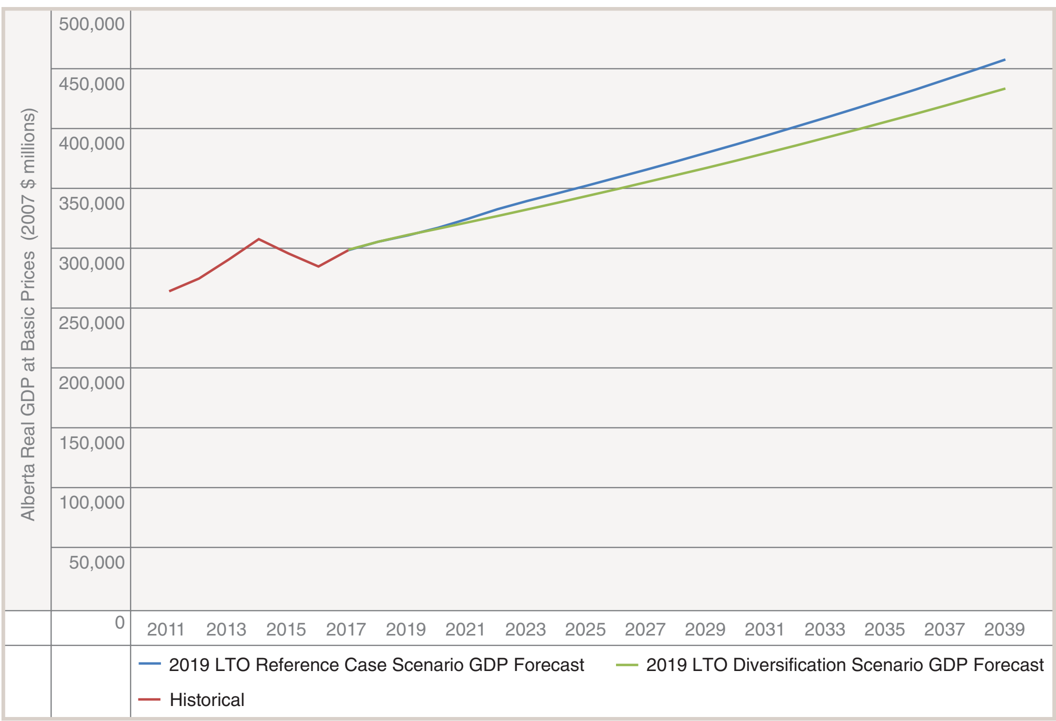
Alberta is well positioned to diversify its economy because of a skilled workforce that can apply experience from the telecommunications industry and oil and gas sector to emerging industries such as biomedical and artificial intelligence. In general, the expectation is that provincial load growth is similar to the Reference Case but with regional differences resulting from changes to the Alberta economy.

On the generation side, the Diversification Scenario tests the impact of a more diversified generation capacity mix which includes new and different technologies. With uncertainty around the future of the oil and gas industry, this scenario in effect sets Alberta's growth in a new direction, with less reliance on its traditional resource base.

### 6.4.1 Diversification Scenario Load Assumptions

The Diversification Scenario tests the impacts of technological change and new industries on load growth in Alberta. A variety of load assumptions used in this scenario are detailed in this section. With stagnant growth in the oilsands industry beyond 2021 due to no new export pipelines, Alberta's economy grows at a moderate pace due to diversification into other industries. The Diversification Scenario GDP forecast is lower than the Reference Case due to non-oilsands industries creating less revenue than the oilsands industry (see Figure 16). The GDP forecast for this scenario is based on one of the most diversified economies in Canada, Manitoba's GDP forecast which is forecast to grow at 1.7 per cent annually between 2018 and 2039.[17] This is slightly below Alberta, which is forecast to grow at 1.9 per cent annually between 2018 and 2039.

**FIGURE 16: Diversification Scenario – GDP Forecast**




In the near term, higher load growth stems from new projects in the petrochemical industry through the Energy Diversification Program.[18] This load growth occurs mostly in Area 33, Fort Saskatchewan. Load also grows up to 2021 from under-construction oilsands projects ramping up production. Oilsands production is assumed to stop after 2021.

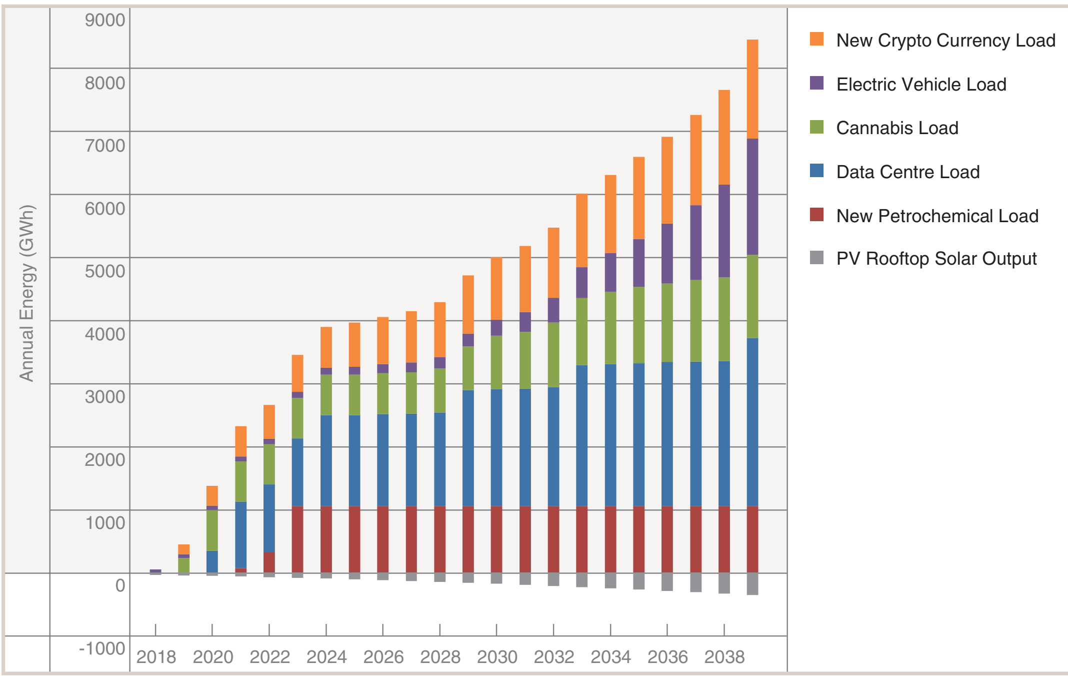
Additionally, load growth arises from electrification, growth in technology hubs (i.e. data centres), increases in cryptocurrency mining operations, higher industrial cannabis farming, growth in services, technology, agri-foods, healthcare industries, and higher adoption of electric demand sources such as electric vehicles. Load growth is higher in the urban areas like Calgary and Edmonton due to increased economic activity unrelated to oil and gas, data centres, cannabis industrial growth, and electric vehicles.

[17] The Conference Board of Canada. Provincial Outlook Long-Term Economic Forecast: Manitoba—2019. Ottawa: The Conference Board of Canada, 2019. https://www.conferenceboard.ca/e-library/abstract.aspx?did=10117

[18] https://www.alberta.ca/energy-processing.aspx#toc-1

EVs are forecast to reach 678 MW by 2039 with data centres reaching 306 MW of new load, and cannabis farming industrial load is expected to reach 282 MW (See Figure 17).

**FIGURE 17: Diversification Scenario – Load Contributors**




### 6.4.2 Diversification Scenario Load Methodology

The methodology to create the Diversification Scenario is similar to that of the Reference Case. Load modifiers are increased to test growth in new industries, and GDP forecasts for the urban areas are increased to test higher growth in those areas. The oilsands forecast used in the Low Growth Scenario is used in the Diversification Scenario to model decreased oilsands load.

### 6.4.3 Diversification Scenario Load Results

In the near term, the Diversification Scenario is higher than the Reference Case due to new data centres and new petrochemical plants. In the longer term, growth in urban centres such as Calgary and Edmonton replaces oilsands growth in the Reference Case. Figure 18 shows the results of the Diversification Scenario, where winter peak load is similar to the Reference Case. The increased data centres, cannabis farming industry, EV, and urban economic growth replaces the oilsands expansions.

**FIGURE 18: Diversification Scenario – Winter Peak Load**

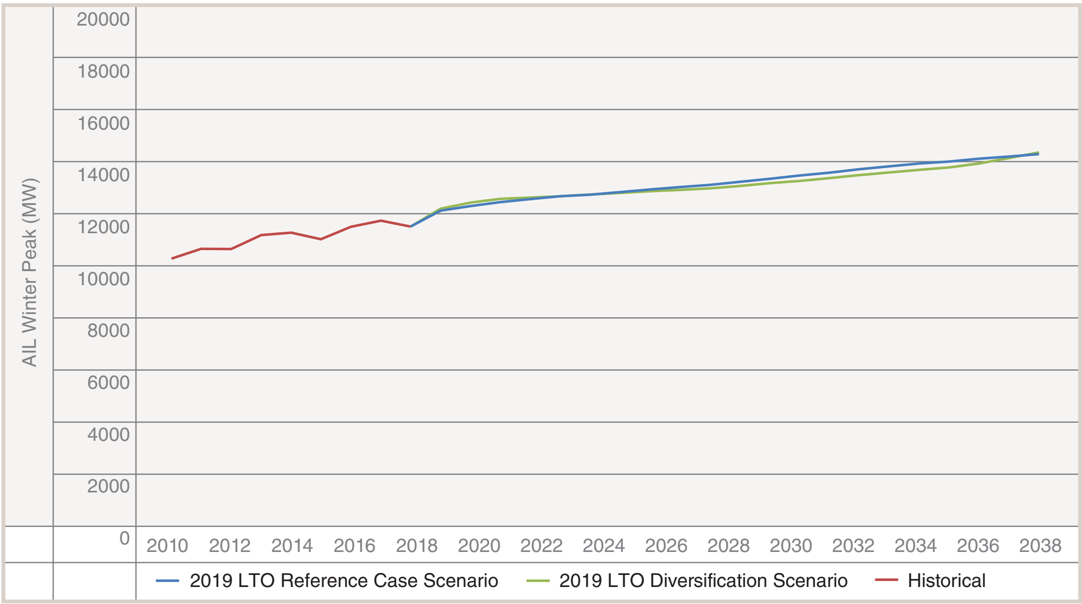



Table 13 shows the increased load growth in the Calgary and Edmonton regions relative to the Reference Case.

**TABLE 13: Reference Case Increase in Calgary and Edmonton Load**

| | Season Year Peak Load | 2019 (MW) | 2029 (MW) | 2039 (MW) |
|---|---|---|---|---|
| Edmonton | Diversification Scenario | 2,272 | 2,580 | 2,967 |
| | Reference Case | 2,243 | 2,393 | 2,553 |
| Calgary | Diversification Scenario | 1,761 | 1,872 | 2,258 |
| | Reference Case | 1,746 | 1,808 | 1,946 |

### 6.4.4 Diversification Scenario Generation Assumptions

The Diversification Scenario tests the impact of a more diversified generation capacity mix. While a variety of drivers could lead to a more diverse generation mix, the primary driver is a change in the cost structure for solar and assumed support for other renewables and storage. In comparison with the Reference Case Generation Scenario, the Diversification Scenario tests a higher energy storage penetration (500 MW) and assumes that more solar capacity develops.

There are many types of energy storage that could develop, including batteries, compressed air and pumped storage. The 2019 LTO does not intend to suggest one energy storage technology is more likely to develop than any other, but has considered four-hour lithium-ion batteries as the primary additions. As well as an expansion in solar and storage, this scenario also assumes an additional 350 MW of hydro generation to be developed late in the forecast. Cogeneration development is assumed to be driven by new industries instead of oilsands growth, which leads to 450 MW less cogeneration than the Reference Case.

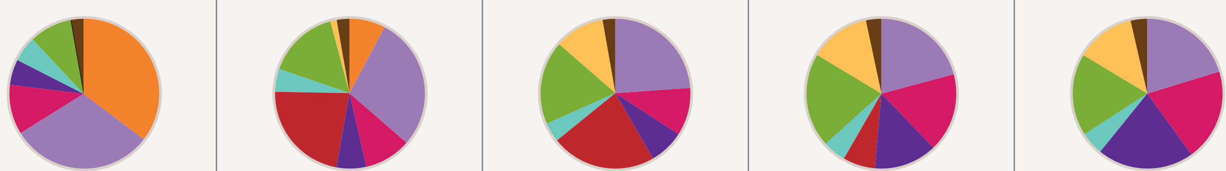
### 6.4.5 Diversification Scenario Generation Results

The Diversification Scenario results compared to the Reference Case include higher renewable generation and a more flexible gas-fired fleet. The percentage of generation from renewable sources is increased and peaks around 2035.

The improved economics of renewables leads to a significant increase in solar capacity – an increase of approximately 2,700 MW relative to the Reference Case. Wind additions also increase by approximately 700 MW compared to the Reference Case. The increases in wind and solar capacity, energy storage, and hydro generation result in reduced need for firm gas-fired generation.

**FIGURE 19: Diversification Scenario – Generation Capacity**

| | Existing | | 2024 | | 2030 | | 2034 | | 2039 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | AIL peak: 11,471 MW | | AIL peak: 12,711 MW | | AIL peak: 13,151 MW | | AIL peak: 13,563 MW | | AIL peak: 14,347 MW | |



| | % | MW | % | MW | % | MW | % | MW | % | MW |
|---|---|---|---|---|---|---|---|---|---|---|
| Coal-fired | 36% | 5,723 | 8% | 1,421 | 0% | 0 | 0% | 0 | 0% | 0 |
| Cogeneration | 31% | 4,937 | 29% | 5,094 | 24% | 5,184 | 21% | 5,184 | 20% | 5,229 |
| Combined-cycle | 11% | 1,748 | 10% | 1,748 | 10% | 2,227 | 17% | 4,143 | 20% | 5,101 |
| Simple-cycle | 6% | 921 | 6% | 1,138 | 7% | 1,603 | 14% | 3,323 | 21% | 5,414 |
| Coal-to-gas | 0% | 0 | 23% | 4,009 | 23% | 4,890 | 7% | 1,729 | 0% | 0 |
| Hydro | 6% | 894 | 5% | 894 | 4% | 894 | 5% | 1,244 | 5% | 1,244 |
| Wind | 9% | 1,445 | 16% | 2,804 | 18% | 3,904 | 20% | 4,972 | 18% | 4,631 |
| Solar | 0% | 15 | 1% | 231 | 11% | 2,331 | 13% | 3,231 | 13% | 3,231 |
| Other | 3% | 423 | 3% | 473 | 3% | 573 | 3% | 773 | 4% | 923 |
| Total capacity | | 16,106 MW | | 17,812 MW | | 21,606 MW | | 24,599 MW | | 25,773 MW |

aeso


# Appendix A: Levelized Cost of Energy

# Levelized Cost of Energy

Levelized Cost of Energy (LCOE) is the average cost per megawatt hour of energy to recover all capital and operating costs, including a specified rate of return, over the entire life of a power generation project. This section provides estimates of the LCOE for select natural gas-fired and renewable generation technologies, including sensitivities on certain key assumptions, in order to understand the relative cost differences between various generation types.

The AESO's LCOE estimates were derived using a discounted cash flow approach, determining the constant value required to cover all expenses. The costs included in the calculation are capital, operating and maintenance (O&M), fuel, carbon emissions, trading charges and transmission line losses. For the purposes of this analysis, income taxes were excluded from the LCOE calculation. While LCOE estimates are helpful to compare the relative economics of different generation technologies, there are limitations to them and LCOE estimates were only one of several sources used in development of the 2019 LTO. LCOEs alone fail to provide a full view of any generation type's profitability in the market. Additional details regarding the limitations of LCOE estimates are included at the end of this section.

## Assumptions

Four technologies were examined:

- Simple-cycle gas turbine, consisting of two aero-derivative turbines with a total net capacity of 93 MW and an assumed capacity factor of 34 per cent
- 1-on-1 combined-cycle (with duct firing) gas plant with a net capacity of 479 MW and an assumed capacity factor of 81 per cent
- Wind generation facility with a net capacity of 100 MW and an assumed capacity factor of 42.5 per cent
- Solar generation facility with a net capacity of 50 MW and an assumed capacity factor of 21 per cent

Assumptions were driven in part from the *AESO Cost of New Entry Analysis,*[1] the *Wind and Solar Assessment* prepared for the AESO by AWS Truepower, LLC[2] and other publicly available information. The following cost assumptions were used in this analysis:

**TABLE 1: LCOE Cost Assumptions in 2020 Dollars**

| Assumptions | Simple Cycle | Combined Cycle | Wind | Solar |
|---|---|---|---|---|
| **Overnight Capital Cost ($/kW)** | 1,450 | 1,344 | 1,924 | 1,898 |
| **Fixed Operating & Maintenance Costs ($/kW/year)** | 56.17 | 52.84 | 36.34 | 33.67 |
| **Variable Operating & Maintenance Costs ($/MWh)** | 4.51 | 2.65 | — | — |
| | | | | |
| **Capacity Factor (%)** | 34.0 | 81.0 | 42.5 | 21.0 |
| **Heat Rate (GJ/MWh)** | 9.68 | 7.03 | — | — |
| **Natural Gas Price Range ($ nominal /GJ)** | 1.58-3.54 | 1.58-3.54 | — | — |

1 https://www.aeso.ca/assets/Uploads/CONE-Study-2018-09-04.pdf

2 https://www.aeso.ca/download/listedfiles/AWS-TruePower-AESO-Wind-and-Solar-Assessment.pdf

LCOE analysis assumed that all plants were financed 50 per cent by debt and 50 per cent by equity, and the debt-to-equity ratio was held constant during the project life. It was assumed that the projects have a 6 per cent cost of debt and a 12.6 per cent cost of equity, resulting in a pre-tax weighted average cost of capital (WACC) of 9.3 per cent for a merchant plant. Projects that have a credible offtaker, such as those with Renewable Electricity Program contracts, could potentially develop at a lower WACC than a merchant plant.

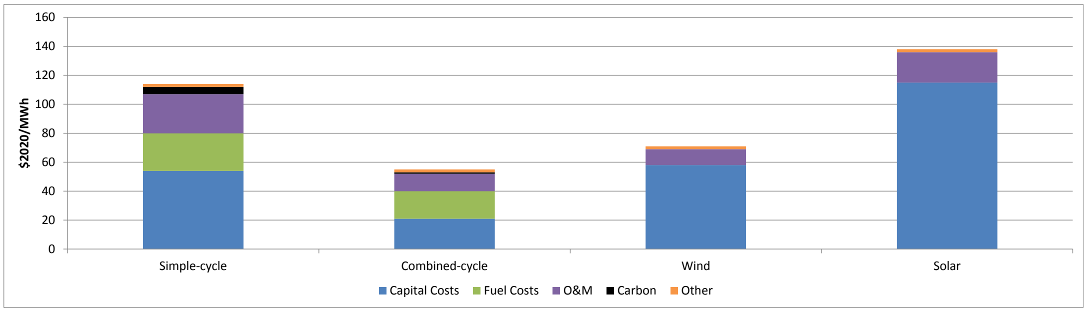
LCOE estimates assumed an in-service date of Jan. 1, 2020 for all technologies and a 20-year economic life was modelled for all assets. The LCOE calculations assumed a carbon price of $20/tonne (t) in 2020, which was increased by 2 per cent annually thereafter. It was assumed that gas units would be benchmarked against a CO2 emission standard of 0.3663 t/MWh in 2020 and the emission standard would decrease by 0.0037 t/MWh each year. In this analysis, the LCOE for wind and solar did not consider any revenue from carbon offsets or carbon credits.

Other cost assumptions included a transmission loss factor of 2.75 per cent based on available forward power prices, a trading charge of $0.47/MWh in 2020 and a commodity fuel charge[3] of 1.66 per cent of gas prices. Trading charges, fixed O&M and variable O&M costs were assumed to increase 2 per cent annually.

Annual capacity factors for simple-cycle and combined-cycle plants were based on the dispatch output from the 2019 LTO Reference Case for new generation units. Capacity factors for wind and solar facilities were based on current, commercially available technologies and resource availability in Alberta.

[3] Commodity fuel charge is the average of the 12-month period (May 2018 to April 2019) of total usage plus MVAR from the fuel usage and measurement variance table from NOVA Gas Transmission Ltd. (NGTL).

**FIGURE 1: LCOE Results for Projects in Service in 2020**

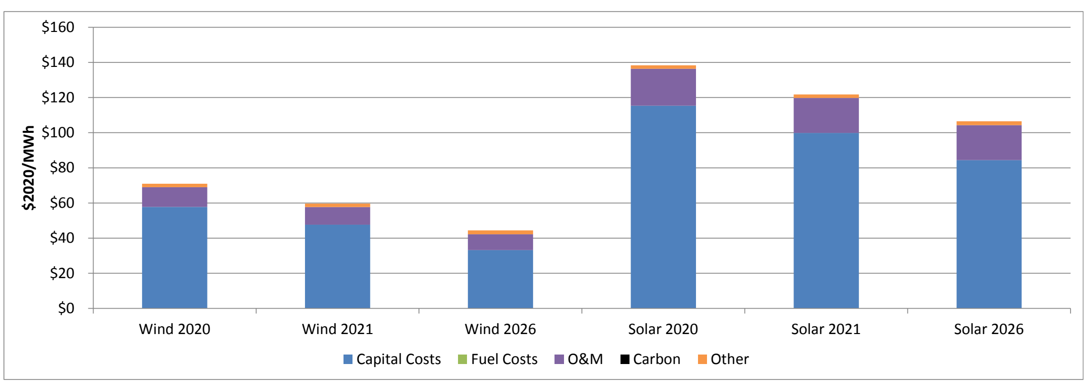



LCOE results shown in Figure 1 are displayed in 2020 dollars per megawatt hour (MWh). The results show that within the technologies considered in this analysis, combined-cycle generation is the least expensive technology at $55/MWh. Wind is the second least expensive technology with an LCOE of $71/MWh. Both simple-cycle and solar have higher LCOE values at $114/MWh and $138/MWh respectively. Capital costs are the largest component of the LCOE for renewable technologies, while fuel, capital cost, and O&M make up the largest components for the thermal units.

The LCOE for future wind and solar generation projects are expected to decline based on continuing capital and fixed O&M cost improvement in these technologies. As such, the wind and solar LCOE has been calculated for two future timeframes and are shown in Figure 2. These LCOE estimates are for the 2021-2025 and the 2026-2030 timeframes. The base LCOE for wind is $71/MWh, declining to $60/MWh in 2021 and to $44/MWh in 2026[4]. The base LCOE for solar is $138/MWh, declining to $122/MWh in 2021 and to $106/MWh in 2026[5].

Given the reduction in capital and fixed O&M costs, wind becomes the lowest-cost technology in future timeframes. As previously indicated, revenue from any emission credits or green attributes have not been included for the renewable technologies.

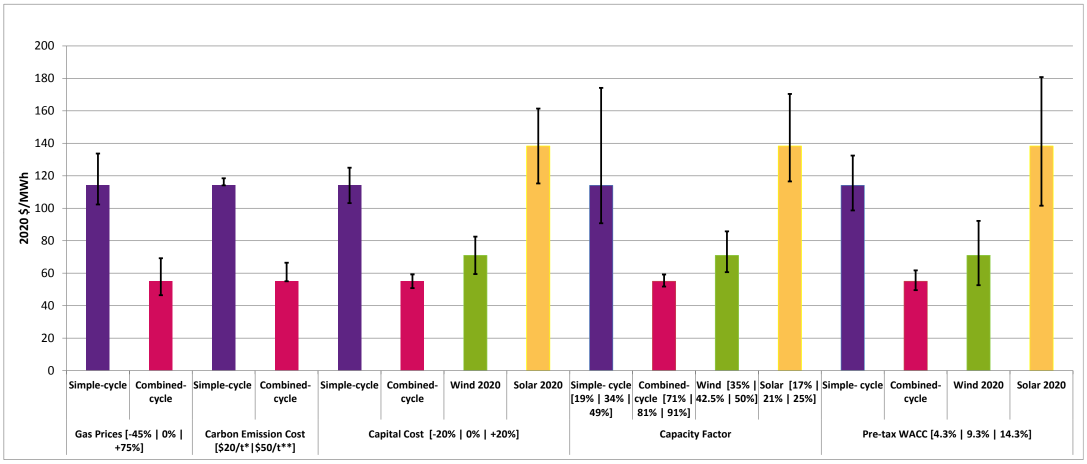
**FIGURE 2: LCOE for wind and solar at different time intervals**




[4] Wind capital cost and fixed O&M (FOM) in 2020 are $1,924/kW and $36.34/kW per year respectively. Wind capital cost and FOM in 2021 are $1,586/kW and $32.50/kW per year respectively. Wind capital cost and FOM in 2026 are $1,105/kW and $29.25/kW per year respectively.

[5] Solar capital cost and FOM in 2020 are $1,898/kW AC and $33.67/kW AC per year respectively. Solar capital cost and FOM in 2021 are $1,643/kW AC and $31.85/kW AC per year respectively. Solar capital cost and FOM in 2026 are $1,388/kW AC and $31.85/kW AC per year respectively.

## LCOE Sensitivities




** $20/t in 2020 with 2% escalation thereafter and 0.37 tCO2/MWh in 2020 with decline.*
*** See Carbon Price and Policy in Table 2 for more detail.*

### TABLE 2: Sensitivity Range Values

The following sensitivities were considered:

| Assumptions Change | Simple-cycle | Combined-cycle | Wind-2020 | Solar-2020 |
|---|---|---|---|---|
| **Natural Gas Price** | - 45 / + 75 percent | | n/a | |
| **Carbon Price and Policy** | $30/tonne in 2020, $40/tonne in 2021 and $50/tonne in 2022 and increasing annually 2% thereafter | | — | |
| | Benchmark of 0.37t/MWh in 2020 and thereafter | Benchmark of 0.37t/MWh in 2020 and declining to 0t/MWh in 2030 | n/a | |
| **Capital Cost** | +/- 20 percent | | | |
| **Capacity Factor** | +/- 15 percentage points | +/- 10 percentage points | +/- 7.5 percentage points | +/- 4 percentage points |
| **Pre-tax WACC** | +/- 5 percentage points | | | |

### LCOE Limitations

While LCOE estimates are helpful to compare the relative economics of different generation technologies, they do have limitations, including:

- LCOE is an energy-based cost metric and is highly impacted by energy-based input assumptions such as capacity factors. Using LCOEs to compare different technologies must be used with caution.
- The LCOE is not an indicator of potential profitability or economic viability. Actual investment decisions are influenced by factors and metrics outside LCOE.
- LCOE ignores project risks such as construction issues and regulatory risks.
- The assumptions used in the LCOE are representative only and can vary based on many factors, including: geography, generator application, site specifics, financial strength of the company and changes in technology. All inputs are assumed for a generic greenfield utility-scale plant in Alberta. The LCOE may not necessarily match those derived in other studies that employ different approaches or definitions of cost estimation.

# Appendix B: Technology Assessment Reports

# Technology Assessment Reports

## Introduction

Alberta's electricity industry and technologies are dynamic and constantly evolving. Over the next 20 years, the electricity industry will experience transformational change driven by technology advancements, digitalization, changing consumer preferences and demographics, all leading to a profound impact on the electricity value chain. To ensure the 2019 LTO aligns with current and expected trends, the AESO continually monitors relevant industry developments that may affect future load growth and generation development.

This section is intended to provide background and details of the generation technologies and load modifiers considered in the 2019 LTO.

## Generation in the Forecast

The AESO has examined Alberta's current and anticipated generation mix. The Reference Case generation forecast makes explicit assumptions about the generation types included in the forecast. Taking into account their historical and anticipated role within the Alberta market helps guide the forecast and provides insights into determining the likely costs, location and size of future development of different generation sources. Natural gas and renewables are expected to drive future growth with a nominal amount of storage emerging.

The following generation technologies were considered:

- Natural Gas
  - Combined-cycle
  - Simple-cycle
  - Cogeneration
  - Coal to Gas
- Coal
- Wind
- Solar
- Storage
- Hydro

### Natural Gas Generation

Natural gas-fired generation plays an important role in the Alberta electricity market by providing reliable baseload and peaking capacity. The technology is mature, has locational flexibility, relatively low GHG emissions, and good economics. There are also relatively few barriers to its development. The resource potential of natural gas-fired generation in Alberta is significant and it is expected to be part of the long-term equilibrium mix in Alberta.

#### Combined-cycle

There is currently 1,748 MW of combined-cycle capacity within the province which provides reliable generation. Combined-cycle generation is a system in which a gas turbine generates electricity and the waste heat creates steam to generate additional electricity within a steam turbine. The high efficiency of a combined-cycle unit means it has low variable fuel costs and low CO2 emissions. These projects tend to be larger and more complicated, requiring significant upfront capital investment and development timelines compared to smaller gas-fired units. Combined-cycle units can serve as a replacement for retiring coal-fired units.

#### Simple-cycle

Within the province there is currently 905 MW of simple-cycle capacity. Simple-cycle units operate by burning natural gas fuel in a combustion chamber and propelling hot gas through a turbine in order to generate electricity. They differ from combined-cycle units in that their waste heat is not utilized, leading to a relatively lower thermal efficiency. Simple-cycle generation is an important part of any electrical system as the fast-ramping characteristic is valuable.

There are three types of smaller gas-fired generators that could develop further in Alberta: aero-derivative, frame, and reciprocating internal combustion engines (RICE). Aero-derivative gas turbines are adaptations of gas turbines used in aircraft; these are the most frequently built examples currently in the Alberta market. Their marginal cost and thermal efficiency are in between both the frame and reciprocating engine. Frame gas turbines have a lower capital cost but also a lower thermal efficiency rating compared to the other two technologies. RICE generators use a reciprocating motion to convert energy into power. Relative to the other technologies, they offer a high thermal efficiency but also have the highest capital costs.

#### Cogeneration

Cogeneration is the simultaneous production of electricity and another form of useful thermal energy used for industrial, commercial, heating or cooling purposes. This technology has seen significant development within the province with 5,004 MW currently in operation. Cogeneration is an efficient process to recover energy that would have otherwise been lost. The main driver of cogeneration growth is related to increases or improvements in industrial activities. As industrial activity increases and there is need for both heat and energy, cogeneration is a suitable technology. This means there are inherent constraints in developing future capacity since cogeneration units are co-located with industrial loads and processes. Cogeneration is expected to continue to develop in step with industrial and oilsands expansion.

## Coal to Gas

Existing coal-fired units have the option to switch from using coal as the main fuel to using natural gas. There are a variety of drivers to switch fuel sources, including natural gas prices, environmental standards, potential to extend plant life, and plant operation. The amount of switching is limited to the number and size of existing coal plants, and access to natural gas supplies. Access is not anticipated to be a constraint within Alberta once pipelines are built. Owners of coal facilities have expressed intentions to switch the units from coal to natural gas, and have begun acquiring the required natural gas infrastructure. Applications to convert units to gas have been submitted and approved by the AUC for the Sundance, Keephills, Sheerness and Battle River 5 facilities.

### *Conversion*

Conversion requires modifying an existing coal-fired facility by installing new equipment such as natural gas burners and retiring coal-handling equipment. Converting an existing coal-fired facility to gas is anticipated to require only a short maintenance period. The facility's capacity is expected to remain similar, while the thermal efficiency could see a small reduction.

### *Co-fire*

Co-firing is the ability to combust two different materials, in combination or individually, to generate power. In the case of an existing coal-fired facility, the design could be modified to provide the additional ability to burn natural gas. This allows for more optionality in use of fuel supply and the ability to optimize changes in relative fuel costs. Much of the current coal fleet is constructed with small amounts of natural gas supplemental firing that has recently been utilized to supplement coal consumption, allowing for reduced air emissions and reduced fuel costs. Some units currently have dual-fuel capability and plans have been announced for the Genesee facility to operate as dual fuel.

### *Repower*

Repowering entails the removal of the existing boiler and coal handling equipment and the addition of a combustion turbine and heat recovery steam generator (HRSG). Repowering a unit is more complex in nature, requiring significant plant-specific design and a larger maintenance period to complete the repowering. Capital investment is also higher than other methods of switching a coal-fired unit to natural gas because of the additional cost of a new combustion turbine and HRSG. The thermal efficiency of a repowered unit is anticipated to improve from what was historically observed by the unit, but still not be as efficient as a standard combined-cycle unit.

## COAL GENERATION

There is currently 5,723 MW of coal-fired capacity within Alberta, and coal has historically been the province's core fuel type for baseload generation of power. Based on federal regulations, no new coal-fired facilities are expected to develop. Further, no energy from coal-fired generation is expected beyond Dec. 31, 2029. More details on policy impacting coal-fired generation can be found in Section 3.2.1 of the 2019 LTO.

Table 3 contains the assumed retirement dates for the coal and coal-to-gas units in the 2019 LTO. The coal-to-gas commencement dates are based on publicly available information found within AUC applications or through corporate announcements. These dates reflect a potential conversion date, not the date when the unit could increase its natural gas usage. Given progress made on natural gas infrastructure upgrades, some could operate on natural gas as dual-fuel units before the conversion date.

Retirement dates are based on federal regulations. For units converting to natural gas, this includes a life extension of up to five years for subcritical coal units and up to eight years for supercritical coal units. The retirement schedule assumes that the market will pace retirements so that they do not occur together, and that at most, two units retire in any given year. The actual retirement and coal-to-gas commencement dates will depend on individual asset owner decisions.

**TABLE 3: Coal Retirement Date Assumptions**

| Asset** | Year of Commissioning | End of Useful Life under Federal Coal Regulations | 2019 LTO Coal to Gas Commencement | 2019 LTO Coal to Gas Retirements |
|---|---|---|---|---|
| Battle River #3 (BR3) | 1969 | Dec. 31, 2019* | — | — |
| H.R. Milner (HRM) | 1972 | Dec. 31, 2019* | — | — |
| Battle River #4 (BR4) | 1975 | Dec. 31, 2025* | — | — |
| Sundance #3 (SD3) | 1976 | Dec. 31, 2026 | Apr. 1, 2022 | Dec. 31, 2030 |
| Sundance #4 (SD4) | 1977 | Dec. 31, 2027 | Apr. 1, 2021 | Dec. 31, 2031 |
| Sundance #5 (SD5) | 1978 | Dec. 31, 2028 | Apr. 1, 2022 | Dec. 31, 2030 |
| Sundance #6 (SD6) | 1980 | Dec. 31, 2029 | Apr. 1, 2021 | Dec. 31, 2031 |
| Battle River #5 (BR5) | 1981 | Dec. 31, 2029 | Apr. 1, 2021 | Dec. 31, 2029 |
| Keephills #1 (KH1) | 1983 | Dec. 31, 2029 | Apr. 1, 2023 | Dec. 31, 2032 |
| Keephills #2 (KH2) | 1984 | Dec. 31, 2029 | Apr. 1, 2023 | Dec. 31, 2032 |
| Sheerness #1 (SH1) | 1986 | Dec. 31, 2029 | Apr. 1, 2023 | Dec. 31, 2033 |
| Genesee #2 (GN2) | 1989 | Dec. 31, 2029 | Apr. 1, 2028 | Dec. 31, 2034 |
| Sheerness #2 (SH2) | 1990 | Dec. 31, 2029 | Apr. 1, 2023 | Dec. 31, 2033 |
| Genesee #1 (GN1) | 1994 | Dec. 31, 2029 | Apr. 1, 2028 | Dec. 31, 2034 |
| Genesee #3 (GN3) | 2005 | Dec. 31, 2029 | Apr. 1, 2029 | Dec. 31, 2037 |
| Keephills #3 (KH3) | 2011 | Dec. 31, 2029 | Apr. 1, 2024 | Dec. 31, 2037 |

**These units are assumed to retire at their federally mandated end of useful life.*
***Some units can currently run as dual fuel to a reduced level of capacity.*

## WIND AND SOLAR RENEWABLE RESOURCES

The AESO retained AWS Truepower, LCC (AWST) to assess wind and solar resources within Alberta. The assessment examined wind speed and solar resource intensity, expected capacity factors, correlations between production profiles and the levelized cost of energy for the province of Alberta. This report is available on the AESO website.[6]

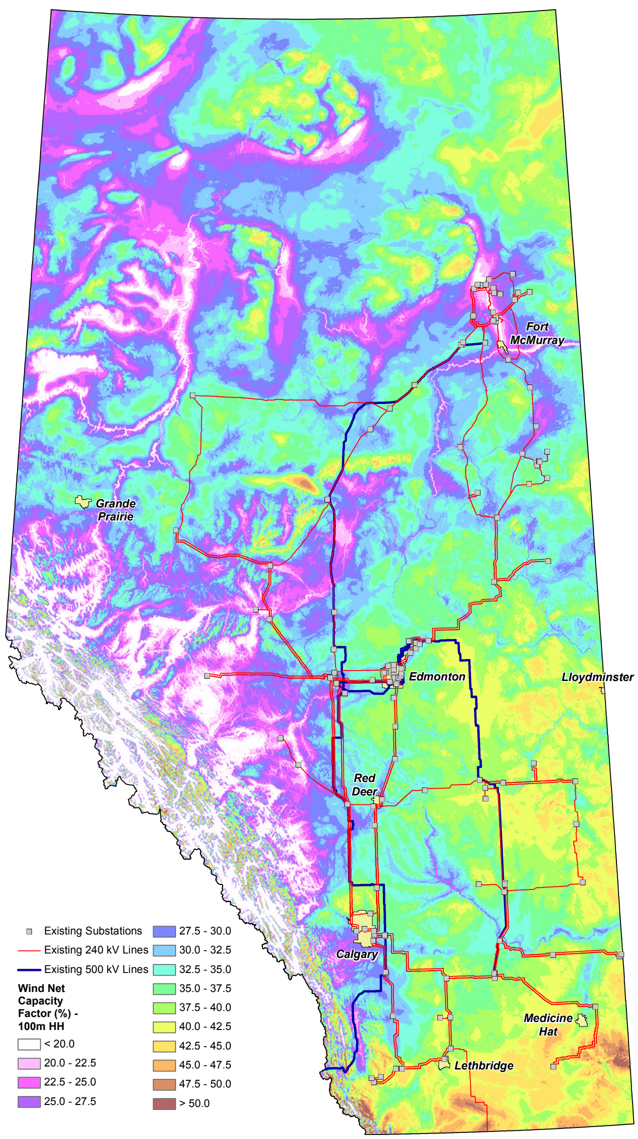
[6] https://www.aeso.ca/download/listedfiles/AWS-TruePower-AESO-Wind-and-Solar-Assessment.pdf

## Wind Generation

The provincial wind fleet capacity is currently 1,445 MW which does not include Renewable Electricity Program (REP) projects; the fleet is projected to double over the near-term horizon due the addition of these projects. The wind industry is anticipated to continue to move towards larger units with taller towers and longer rotor blades, leading to larger ratings of turbine units and increased energy capture.

The wind resource map in Figure 4 shows the mean annual wind speeds at a wind turbine height of 100 metres. Studies show the highest wind speeds are anticipated in the south and central east portions of the province, with the potential for some small wind development in the northwest and northeast. The 2019 LTO assumes continued wind growth over the forecast horizon, primarily in southern and eastern parts of the province.

**FIGURE 4: Alberta Wind Resource Map**



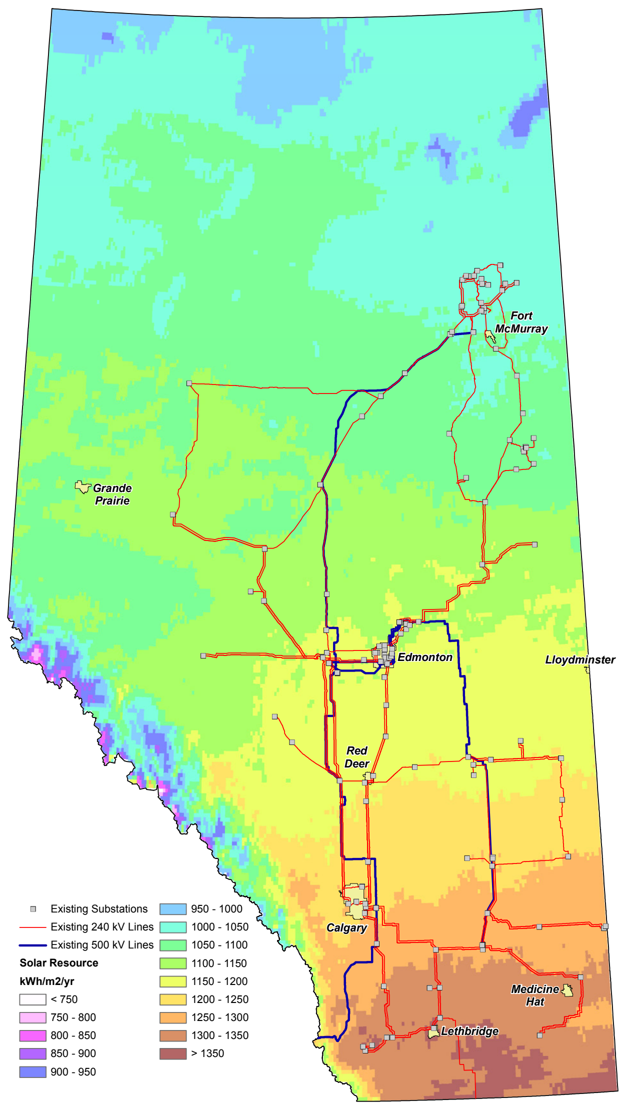

*Source: AWS Truepower, LLC*

## Solar Generation

There is currently over 50 MW of solar microgeneration in Alberta,[7] and the province's first large-scale solar project, the 15 MW Brooks Solar plant, began operation in 2017.

The solar resource map in Figure 5 shows the mean annual irradiation. Solar potential is relatively more abundant along the southern border compared to northern locations. The 2019 LTO assumes some continued growth in solar capacity over the forecast horizon. Improvements in technology, including bi-facial panels and track mounting, are increasing the amount of energy captured.

**FIGURE 5: Alberta Solar Resource Map**




*Source: AWS Truepower, LLC*

7 https://www.aeso.ca/market/market-and-system-reporting/micro-generation-reporting/

### Storage

Alberta currently does not have any transmission-connected energy storage projects; however, multiple projects have applied for connection and some have received funding to support their development. Energy storage technologies that have applied for connection within Alberta include lithium-ion batteries, compressed air energy storage and pumped hydro storage. Currently across the U.S. and other global jurisdictions, energy storage technologies are being considered and installed for many purposes. These include energy price arbitrage, ancillary services, transmission and distribution investment deferral, voltage and frequency support, back-up supply, enabling intermittent generation dispatch, and emissions reductions.

There are multiple factors that make the economics of energy storage challenging in Alberta, including transmission charges and limited opportunities for revenues within the operating reserve markets.[8] While the current legislated framework does not prohibit the participation of energy storage in the energy and ancillary services markets, in practice the existing legislation, regulations and AESO Authoritative Documents do not fully contemplate the unique attributes and challenges associated with the participation of energy storage in Alberta's electricity system. The A*ESO Energy Storage Roadmap*[9] will approach energy storage as a unique asset type, facilitate integration, and will be impartial to energy storage technology.

### Hydro

Alberta currently has 894 MW of installed hydro capacity with significantly more hydro potential. In the 1950s, about half of Alberta's generation source was hydro. Since then, the generation mix has changed significantly due to capitalization of the province's low-cost coal and gas resources. Several other challenges also constrain the development of Alberta's hydro facilities, including long construction periods, substantial capital costs, location challenges, and significant environmental impact. Moreover, about 75 per cent of Alberta's potential hydro capacity is located in the Athabasca, Peace River and Slave River basins within the northern part of the province.[10] Remoteness of these basins increases transmission difficulties and cost.

Hydro generation is one of the most technologically mature renewable generation solutions as it has a long operation history, well-established operational knowledge base, and the highest generation efficiency among all power generation methods. Its main operational principle is to convert potential and kinetic energy of running water into electrical energy using turbines. Since hydro generation is sustainable, highly efficient, and emits very little greenhouse gas, it is regarded as a promising solution to meet GHG emission targets by many countries around the world.

There are two major types of hydro generation methods: impoundment and diversion. Impoundment is the most common facility and employs a dam to store water in a reservoir, releases it to activate the turbines when electricity is needed, and finally converts mechanical energy into electrical energy. A diversion facility is also known as run-of-river and it channels a portion of a river through a canal or penstock.[11] A dam is not required for a diversion facility.

[8] See the AESO's Dispatchable Renewables and Energy Storage Report for further details on energy storage within Alberta

[9] https://www.aeso.ca/market/current-market-initiatives/energy-storage/

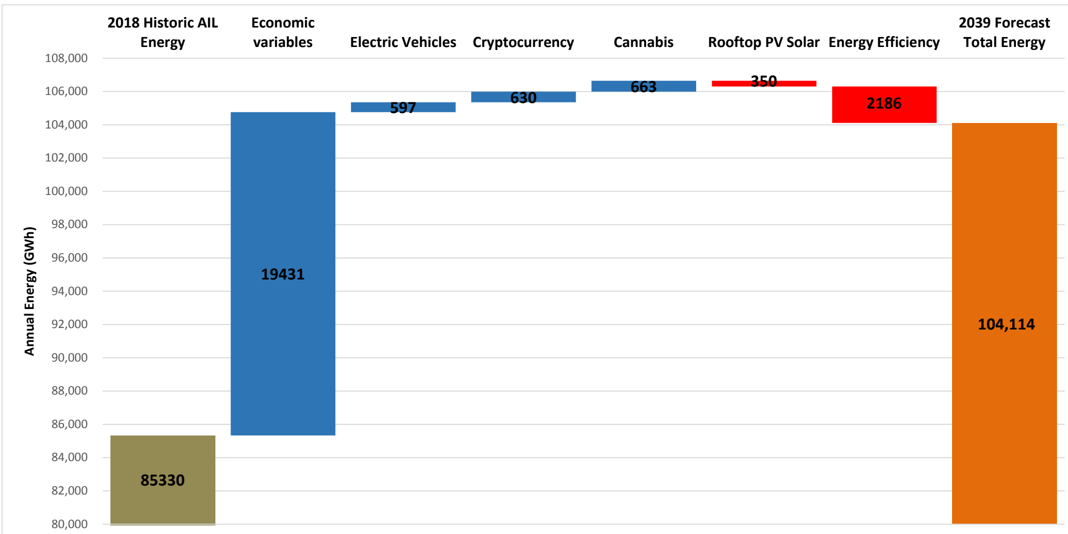
[10] http://www.history.alberta.ca/energyheritage/energy/hydro-power/hydroelectricity-in-alberta-today.aspx

[11] https://www.energy.gov/eere/water/types-hydropower-plants

## Load Modifiers in the Forecast

The AESO has carefully considered several load modifiers that have emerged rapidly in the last few years in Alberta. The Reference Case load forecast makes explicit assumptions about the future of the cannabis farming industry, rooftop solar photovoltaics, cryptocurrency mining operations, and electric vehicles. While cryptocurrency mining operations and cannabis farming lead to higher load growth in the near term, electric vehicle adoption adds to load more rapidly as adoption increases in the longer term. Rooftop solar contributes to a decline in grid-served load over the longer term. Figure 6 shows the breakout of load growth and reductions for the Reference Case Scenario from 2018 through 2039.

**FIGURE 6: Composition of Load Growth 2018-2039 (Reference Case)**




The following load modifiers were considered:

- Cannabis Farming Industry
- Cryptocurrency Mining and Data Centres
- Electric Vehicles
- Rooftop Solar Photovoltaics

## Cannabis Farming Industry

The Government of Canada legalized cannabis production, an electricity-intensive agricultural commodity, on Oct.17, 2018. Consequently, many producers have constructed or are in the process of constructing production facilities in Alberta to take advantage of low electricity rates.[12] Large-scale indoor warehouse production requires high intensity light, cooling and dehumidification for the three stages of cannabis growth. In contrast, greenhouse growing, which currently comprises the majority of production in Alberta, reduces energy demand when compared to exclusively indoor warehouse operations because of reduced lighting needs and the infrastructure required to deal with intense heat generated by the bulbs. For this reason, the cannabis farming industry load analysis assumed a different load profile for greenhouses and warehouses in order to calculate the electricity intensity of each facility.

[12] https://www.canada.ca/en/health-canada/services/drugs-medication/cannabis/laws-regulations.html

The load forecast for the cannabis farming industry is based on electricity intensity calculations, size and type of facility, announced and under-construction facilities in Alberta, and the examination of licenses granted by Health Canada. The load at each substation is verified with facility applications in order to determine the forecast at each substation, and is then reconciled into the regional-level forecasts. The majority of growth is forecast to emerge in Edmonton and the Southern Alberta region.

With high demand for growing operations setting up in the short term, saturation of this industry is likely to occur in the longer term. Capacity added in the next five years is forecast to peak in the year 2020, after which supply catches up with demand, resulting in limited growth past 2020. The analysis assumes that growth in the cannabis farming industry in the long term will be captured by the economic growth index in the forecast.

### Cryptocurrency Mining and Data Centres

Cryptocurrency mining is an electricity intensive process in which transactions for various forms of cryptocurrency are verified and added to the blockchain digital ledger. In the last few years, Alberta has seen an emergence of both large-scale and smaller-scale cryptocurrency mining operations. These facilities are attracted by Alberta's cool weather and low electricity costs compared to the higher rates and regulations found in other international jurisdictions. The local speed and reliability of the internet and a solid legal framework are almost as important, which is why Alberta is an ideal location for cryptocurrency mining operations. Currently Alberta has approximately 110 MW of mining in operation.

The forecast of load from cryptocurrency mining operations in the 2019 LTO is based on industry research and current and existing applications. Because many new projects in the AESO's Project List[13] have not materialized in the past year, the forecast is conservative with 72 MW of new cryptocurrency mines being added by 2039. With some other Canadian jurisdictions recently offering attractive rates and discounts for new load customers and the volatility in many cryptocurrencies, the analysis does not expect load from these operations to grow significantly in Alberta.

In addition to cryptocurrency mining operations, data centres are also included in the forecast. The Diversification Scenario forecasts smaller data centres in urban areas, and the High Growth Scenario includes a larger data centre in the Edmonton Planning Region. No data centers are included in the Low Growth Scenario forecast.

### Electric Vehicles

The AESO forecasts electric vehicle (EV) volumes to better understand the impacts that these resources may have on system-level demand forecasts. Currently, EV levels do not have a material impact on load, given their small volume in Alberta and the corresponding charging demand relative to total system demand. The AESO recognizes that technological advances may enable aggregation of EVs and the participation of aggregated EVs as vehicle-to-grid resources into the electricity market, and as potential resources to be used to optimize distribution systems.

EVs include battery-powered electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs). Both can be charged by plugging into an electricity source and in the future have the potential to discharge back onto the grid. Although Alberta's EV numbers are still low, they are growing exponentially, with EV registrations in Alberta up 759 per cent over five years. As of March 2019, there were 1,297 BEVs and 20,702 hybrid vehicles in Alberta.[14] PHEV data is not available separately from hybrid electric vehicle data.

[13] https://www.aeso.ca/grid/projects/project-reports/

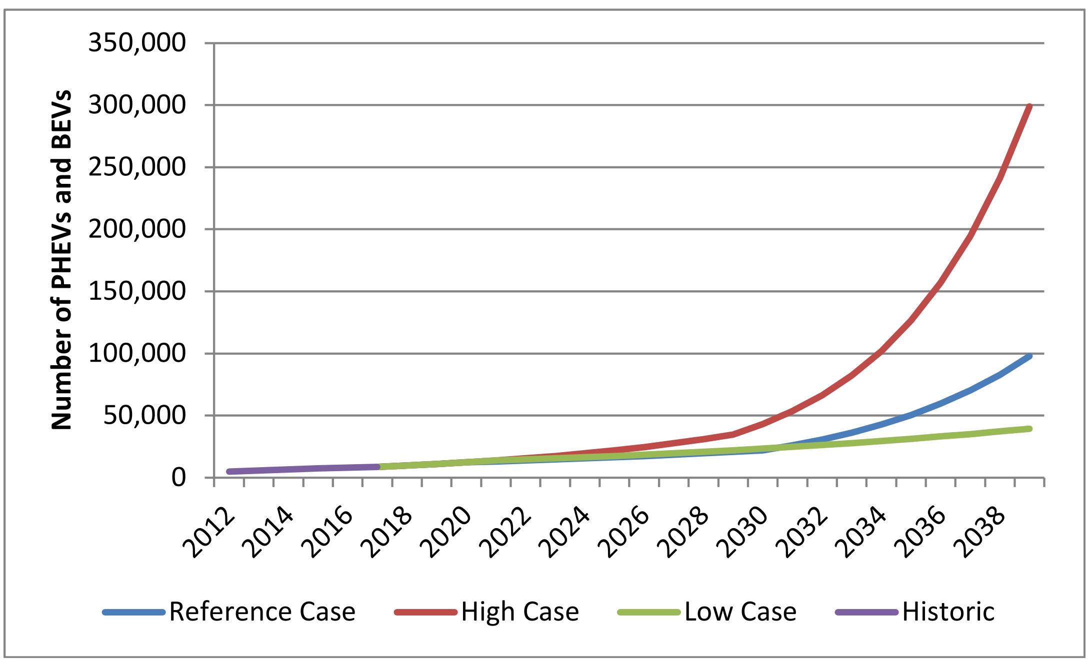
[14] https://open.alberta.ca/dataset/c5eb22a7-f3e6-41ce-8363-17d1ea979bc7/resource/a0aba675-6a0d-4ed5-baa2-9c54e4ea77ff/download/vehicle-registrations-fuel-type-2019.pdf

The EV analysis was conducted using available data as of March 2018 when BEVs were approximately 635 or 0.02 per cent of all registered vehicles and hybrids were 18,364. In order to analyze the impact on the electricity grid, half of hybrid EVs (approximately 8,000) were assumed to be PHEVs located in major city centres such as Calgary and Edmonton. Vehicle purchasing patterns in Alberta indicate a preference for light-duty trucks which make up approximately a third of vehicles on the road today. Although there are few PHEV offerings for SUVs and trucks today, the analysis assumes that with higher availability of trucks, EV adoption is likely to increase in the province. A separate load profile is created for trucks and cars, as trucks would consume more electricity due to their larger battery size. In addition, a separate winter and summer weather residential load profile is estimated for the summer and winter months due to increased power demand for heating, and decreases in efficiency of engines and batteries from colder temperatures. Charging profiles were sourced from an EV study done on behalf of Yukon Energy Corporation.[15]

The EV analysis includes a Low, Reference, and High EV adoption case with varying assumptions on adoption rates. The tipping point, when EVs are the same price as internal combustion engine cars, is assumed to be 2030 for both the Reference and High cases. No tipping point is assumed for the Low case where battery cost reductions, increased range, policy incentives, and oil/diesel price increases do not occur. At the time of conducting this analysis, no federal incentive program was announced such as the one in place today.[16]

The Low Growth Scenario uses the Low EV adoption case, while the High Growth and Diversification Scenarios use the High EV adoption case and the Reference Case Scenario uses the Reference EV adoption case. Figure 7 shows the results of each case included in the electric vehicles analysis.

**FIGURE 7: EV Scenario Results**




[15] https://yukonenergy.ca/media/site_documents/Yukon_EV_Investigation_Report.pdf

[16] https://emc-mec.ca/new/federal-ev-incentive-program-to-start-on-may-1-2019/

### Rooftop Solar Photovoltaics

Solar generation is a rapidly growing resource in Alberta with three primary growth drivers: government policy combined with targets and/or incentives; economic incentives to save on electricity costs; and strong consumer demand for greener energy. In the 2019 LTO forecast, behind-the-meter rooftop solar is treated as a reduction in load. Adoption is based on a projection of the historic uptake rate, economic incentive, and projected Alberta housing stock.

Rooftop solar reduces transmission and distribution costs for residential and commercial customers. The revenue from producing electricity and reduction in transmission and distribution costs creates a return on the solar investment. If the electricity revenues and transmission and distribution cost savings provide a large enough return relative to the initial solar investment, a percentage of those customers will install solar. The higher the return, the more customers are expected to adopt this new technology.

The AESO assumes that while a higher economic return increases rooftop solar adoption, only a small percentage of those with the economic incentive to adopt solar will follow through and install panels. The assumption is that only two to three per cent of those with an economic incentive will actually adopt solar by 2039 in the Reference Case Scenario, and three to five per cent in the Low Growth Scenario. Higher percentage adoption corresponds to a high return and lower percentage adoption corresponds to a low return. This assumption that only a small percentage of those with an economic incentive will install rooftop solar is made to account for customers who are not aware of the economics of solar, and those who are aware but choose not to adopt for other reasons.

Historic adoption follows an exponential function – the uptake of solar increased exponentially over the past ten years. The historic trend has been extrapolated out into the future. The variable charge for transmission and distribution forms a large portion of the savings experienced by customers who install solar, which is why areas with the highest charges remain the most attractive areas for solar adoption in Alberta.


# Appendix C:
# Other Considerations

# Other Considerations

## Introduction

In addition to the technology assessments described in Appendix B, the AESO further evaluated other forecast considerations as part of the 2019 LTO process. This section is intended to provide background and details of these other considerations. While only some of the items described are considered in the 2019 LTO, it is important to consider their potential impacts on future load and generation. The AESO will continue to track emerging trends and developments and adjust future Long-Term Outlooks and scenarios as required.

The following potential generation technologies were considered:

- Small Nuclear Reactors
- Geothermal
- Hydrogen

## Small Nuclear Reactors

Nuclear power generation is a type of thermal power in which electricity is generated from steam produced by the fission, or splitting, of uranium atoms. The major difference between nuclear power generation and coal or natural gas-fired generation is the fuel source. Nuclear power plants use uranium for fuel, and instead of burning it, they use the heat created by the nuclear fission process.

In recent years, the potential to use a small-scale nuclear reactor to generate power for remote communities and smaller electrical grids has been explored extensively. These novel, small-scale nuclear generation technologies are commonly referred to as Small Modular Reactors (SMRs). In contrast to traditional nuclear reactors that typically have generation capacity of up to 1,600 megawatts electric (MWe), SMRs usually generate less than 300 MWe and are significantly smaller in size.[17]

Just like traditional nuclear reactors, SMRs use fission to create heat to power steam turbines and generate power. However, their approach to fuel cooling is quite different. Traditional nuclear reactors use the Canada Deuterium Uranium (CANDU) design, which is a type of Pressurized Water Reactor (PWR), while SMR designs propose several different materials such as circulating gas, molten salt and liquid metal to act as fuel coolants.[18] Currently there are four main SMR design options being considered: light water reactors, fast neutron reactors, graphite-moderated high temperature reactors, and molten salt reactors. The light water reactors are the most technologically feasible, while the fast neutron reactors feature a smaller, simpler design and have a longer operation period.[19]

With an increased interest in developing these modular reactors, many countries have become actively involved in the research and development of this technology with the U.S., U.K., Canada, China, and Russia leading the way. The U.S. government has invested substantially in developing the light water-cooled SMRs that will likely be deployed in the next 10 to 15 years. In addition, a 60 MWe unit could start to operate in the mid-2020s in the U.K. The most advanced SMR project is currently in China. It consists of two high temperature gas-cooled reactors which could generate 210 MW of

17 https://www.cbc.ca/news/canada/calgary/nuclear-power-oilsands-1.5142864

18 https://nuclearsafety.gc.ca/eng/resources/news-room/feature-articles/ready-to-respond-smrs.cfm

19 http://www.world-nuclear.org/information-library/nuclear-fuel-cycle/nuclear-power-reactors/small-nuclear-power-reactors.aspx

electricity.[20] This SMR is expected to start generation in late 2019. In Canada, the Canadian Nuclear Safety Commission (CNSC) has received the first license application from Global First Power for an SMR to be deployed at Chalk River in Ontario.[21] This SMR is a 15 MW (thermal), 5 MW (electrical) high temperature gas reactor which is expected to begin operation by 2026. Moreover, nine other small reactors have been conducting pre-licensing vendor design reviews with the CNSC.

Though SMRs require less capital costs and construction time than traditional nuclear power plants, their licensing and regulatory process is not necessarily less than that of larger nuclear plants due to security concerns. For instance, CNSC's pre-licensing vendor design review process could take 5,000 hours of staff time for Phase I and twice the time for Phase II.[22] This lengthy administrative process poses significant challenges for investors and government authorities. In addition, the technology for developing SMRs is not as mature compared to traditional nuclear reactors, therefore wide implementation of SMR design is not expected in the near future. However, many efforts have been made to push for the strategic development of SMR technology in Canada. The Canadian government conducted a nationwide study on SMR technology in 2018 with partnered provinces and power utilities to construct a roadmap that outlines future steps in development and deployment of SMRs in Canada. Alberta Innovates is an active participant in the structuring of this roadmap and has expressed interest in building SMRs for heavy industry applications such as oil and gas extraction.

### Geothermal

As a renewable energy source, geothermal technology extracts heat from the Earth's inner layers to produce electricity. In most cases, this is accomplished by pumping fluids from several thousand feet below ground to an electrical generating facility. Geothermal energy is considered a renewable energy source because when managed efficiently, a site will provide a long-term supply of heat.

Electricity can be generated from geothermal energy in two main ways: flash and binary. Flash systems pump high-pressure, high-temperature fluids up into a low-pressure chamber, driving a generator with the steam produced from the resulting pressure change. Binary systems facilitate a heat exchange between geothermal water and a hydrocarbon with a low boiling point. The hydrocarbon vaporizes and the steam produced is used to generate electricity and heat. Enhanced Geothermal Systems (EGS) enhance or replenish a geothermal reservoir by injecting water into the site, thereby allowing for flash or binary generation.

[20] https://www.neimagazine.com/features/featurehtr-pm-making-dreams-come-true-7009889/

[21] http://world-nuclear-news.org/Articles/First-Canadian-SMR-licence-application-submitted

[22] http://www.world-nuclear.org/information-library/nuclear-fuel-cycle/nuclear-power-reactors/small-nuclear-power-reactors.aspx

In Alberta, geothermal energy systems are currently limited to small residential heating and cooling systems. However, a few pilot projects have been developed to exploit the potential of geothermal energy which include electricity generation. A project at Swan Hills is a hybrid geothermal power plant that generates electricity using both geothermal power and existing oil and gas infrastructure. This project, developed by Razor Energy Corp., is expected to provide three to five MW of electricity from geothermal energy and 15 MW of electricity from natural gas-powered turbines.[23] This project allows Razor Energy to add some economic value through renewable energy development to its existing hydrocarbon assets. In addition to this, another commercial geothermal project located in Greenview has received $25.45 million of funding from the federal government. The Greenview project is expected to have capacity of 5 MW and reduce greenhouse gas emissions by about 20,000 tonnes.[24]

In addition, a pilot project developed by Eavor Technologies is currently under construction in central Alberta and is expected to be completed by the end of 2019. This project is the world's first truly closed-loop geothermal system, consisting of a large U-shaped tube well at a depth of 2.4 km, with several kilometres of multilateral horizontal wellbores and a pipeline connecting the sites on the surface. The Eavor-Loop project is not intended to be commercially viable; instead, it aims to demonstrate the critical elements of Eavor's technologies at the lowest cost in order to achieve the most efficient path to commercialization.[25]

The resources in the northwest region of the province are the most suitable for geothermal development. However, with a low geothermal gradient averaging 30°C/km, Alberta is not geologically situated to develop large-scale geothermal power generation.[26] Early estimates limit future geothermal generation in Alberta to beween 300 and 500 MW.[27]

### Hydrogen

Hydrogen is one of the most abundant elements found on Earth. On its own, hydrogen does not act as a fuel or energy provider; however, when it burns, it reacts with water to create heat that is then used for energy.[28]

As an energy carrier, hydrogen provides a few advantages that other feedstocks lack:

- it can be used without direct emissions of air pollutants or greenhouse gases;
- it can be made from a diverse range of low-carbon energy sources such as biomass and nuclear power.[29]

[23] https://www.ualberta.ca/science/science-news/2019/july/geothermal-energy-pilot

[24] https://www.dailyheraldtribune.com/news/local-news/geothermal-power-plant-under-development-in-greenview

[25] https://www.jwnenergy.com/article/2019/8/drilling-underway-10mm-alberta-geothermal-project/

[26] The rate of increasing temperature in relation to the increasing depth below the earth's surface: Simulation of Geothermal Flow in Deep Sedimentary Basins in Alberta, T. Graft, Energy Resources Conservation Board Alberta Geological Survey, July 2009.

[27] Borealis GeoPower. CanGea 3rd Geothermal Power Forum, November 4, 2011

[28] http://www.chfca.ca/education-centre/what-is-hydrogen/

[29] https://www.g20karuizawa.go.jp/assets/pdf/The%20future%20of%20Hydrogen.pdf

The production of hydrogen uses natural gas, coal, biomass, oil, and other renewable energy sources. Though hydrogen itself is regarded as a clean fuel, its production process can be quite polluting since it is almost entirely supplied by coal and natural gas today. However, some environmentally friendly production methods and improvements have been invented to remedy this issue. These technologies allow hydrogen to be captured from waste generated by industrial processes, and Carbon Capture and Storage technology to be integrated with hydrogen production processes to reduce carbon dioxide emissions.

Currently, the global hydrogen demand is dominated by industrial processes such as oil refining, ammonia production, methanol production, and steel production.[30] However, hydrogen's energy carrier characteristic extends its use to various other applications, especially in our current energy supplies.[31] It can be used as a vehicle fuel in both internal combustion engines and fuel cells. Because of its easy-to-store nature, it can also be first generated using wind, solar, nuclear and hydroelectric power, then stored for future use. The use of hydrogen in the power sector helps to balance load and renewable generation.

Of the existing and potential applications of hydrogen, hydrogen fuel-cell is the emerging technology that has received the most publicity. Hydrogen fuel-cells enhance the performance of clean energy systems by balancing fluctuations in energy loads. They are therefore regarded as an effective technology in the trend towards renewable energy alternatives.

Canada is one of the largest hydrogen producers in the world and its pioneering technologies are well recognized around the globe. The sector develops hydrogen fuel-cell applications for passenger vehicles, ships and planes, stationary and back-up power, and material handling. 51 per cent of fuel-cell facilities are located in British Columbia and 18 per cent are located in Ontario.[32] Alberta has only about 2 per cent of Canada's total hydrogen fuel-cell facilities, but the province recently started an industry-led, $15 million project that will test the ability of hydrogen to fuel the province's heavy-duty freight transportation sector.[33] This project involves the design and manufacture of two heavy-duty, hydrogen fuel-cell electric hybrid trucks that will transport freight year-round between Edmonton and Calgary.

[30] https://www.g20karuizawa.go.jp/assets/pdf/The%20future%20of%20Hydrogen.pdf

[31] http://www.h2fcprogress.collaboration.gc.ca/publ/pdf/upd-mis-eng.pdf

[32] http://www.chfca.ca/media/CHFC%20Sector%20Profile%202018%20-%20Final%20Report.pdf

[33] https://www.cesarnet.ca/blog/15-million-project-test-hydrogen-fuel-alberta-s-freight-transportation-sector

## Industries, Technology and Trends

The following industries, technologies and trends were considered:

- Petrochemical and Industry
  - Oilsands Extraction Technologies
  - Petrochemical
  - Export Pipelines
  - Carbon Capture and Storage

- Technology and Trends
  - Small Household Storage
  - Smart Meters
  - Smart Grid

## PETROCHEMICAL AND INDUSTRY

### Oilsands Extraction Technologies

The oilsands sector is a key driver of the provincial economy and a pivotal industry for electricity demand and supply. The 2019 LTO models load associated with the oilsands sector using SAS energy forecasting software. The oilsands forecast for the 2019 LTO is inputted into the econometric models for regions, areas and PODs that are known to have oilsands-related load. The econometric model trains on historic data and determines the quantitative relationship between electricity demand and oilsands production. The oilsands forecast is then used to forecast load growth along with the GDP forecast and other inputs. The forecast assumes that current extraction technologies like SAGD and mining will continue to be used in the future.

There are a number of other extraction technologies currently being developed that could be applied on a large scale in Alberta's oilsands. The main focus of new technologies is to reduce the amount of water and energy used to extract bitumen. Projects include Petroteq's Clean Oil Recovery Technology,[34] CanmetENERGY's Direct Contact Steam Generation,[35] and Imperial Oil's Enhanced Bitumen Recovery Technology.[36]

### Petrochemical

Petrochemicals are a category of chemicals derived primarily from two feedstocks: natural gas liquids (NGL) obtained from natural gas processing plants, and oil refinery streams such as naphtha and light gas oil.[37] Some common petrochemicals include propane, ethane, ammonia, formaldehyde, and urea. The wide applications of these petrochemicals make them ubiquitous in our daily life. Plastics packaging, fertilizer, and synthetic rubber are just a few examples.

Studies have shown that growth of petrochemical products correlates with world GDP and the demand for petrochemicals is surging continuously.[38] As a result, the manufacturing, consumption, and trade of petrochemicals have significant impact on the global economy. The petrochemical industry also plays a crucial role with respect to environmental considerations such as GHG emission intensity and plastic recycling.

[34] https://petroteq.energy/technology/oil-sands-extraction

[35] https://www.cosia.ca/initiatives/water/projects/direct-contact-steam-generation

[36] https://www.jwnenergy.com/article/2018/5/alberta-invests-70-million-clean-bitumen-production-technologies/

[37] https://www.ic.gc.ca/eic/site/chemicals-chimiques.nsf/eng/bt01135.html

[38] https://www.iea.org/petrochemicals/

Fueled by abundant and low-cost feedstock, Alberta has the largest petrochemical production within Canada, accounting for nearly 45 per cent of total petrochemical plants in Canada.[39] The province's petrochemical industry is mainly based on olefins (about 92 per cent of petrochemical production capacity)[40] and accounts for approximately one-third of Alberta's total manufacturing exports.[41]

There is potential for the petrochemical industry to grow in Alberta and the scenarios in the 2019 LTO cover some of the potential sites. The Reference Case Scenario includes one new petrochemical plant opening in Alberta over the next five years, and the Diversification Scenario includes two additional petrochemical plants opening over the same time period.

## Export Pipelines

The major oil pipelines considered in the 2019 LTO are listed in Table 4 below. Some of these projects have been cancelled but are included in the High Growth Scenario to consider the possibility of similar projects being developed in the future.

**TABLE 4: Major Oil Export Pipelines**

| Pipeline Name | Capacity (bbl/day) | Current Expected Start Date |
|---|---|---|
| Transmountain Pipeline Expansion | 590,000[42] | Mid-2022[43] |
| Keystone XL | 830,000 | 2021[44] |
| Enbridge Line 3 Replacement | 370,000[45] | 2020[46] |
| TC Energy East Conversion Line[47] | 1,100,000 | Cancelled |
| Enbridge Northern Gateway[48] | 525,000 | Cancelled |

[39] https://www.ic.gc.ca/eic/site/chemicals-chimiques.nsf/eng/bt01135.html#clusters

[40] http://ceri.ca/assets/files/Study_169_Full_Report.pdf

[41] https://investalberta.ca/industry-profiles/petrochemicals/

[42] https://www.transmountain.com/project-overview

[43] https://www.cbc.ca/news/canada/calgary/trans-mountain-construction-starts-notice-1.5254743/

[44] https://www.enbridge.com/~/media/Enb/Documents/Projects/Line%203/ProjectHandouts/ENB_Line3_Public_Affairs_ProjectSummary.pdf

[45] https://www.enbridge.com/~/media/Enb/Documents/Projects/Line%203/ProjectHandouts/ENB_Line3_Public_Affairs_ProjectSummary.pdf

[46] https://www.enbridge.com/projects-and-infrastructure/projects/line-3-replacement-program-canada

[47] https://www.cer-rec.gc.ca/pplctnflng/mjrpp/nrgyst/index-eng.html

[48] https://thenarwhal.ca/topics/enbridge-northern-gateway/

## Carbon Capture and Storage

Carbon Capture and Storage (CCS) technology is able to capture up to 90 per cent of the carbon dioxide (CO2) emitted from industrial and electricity generation processes and safely store it deep underground. CCS technology could expand in Alberta depending on climate policy and its competitiveness with other greenhouse gas reducing technologies.

The CCS cycle consists of three major steps: CO2 emissions capture, emissions transportation, and injection of CO2 into deep underground rock formations for permanent storage. Three major methods can be used for CO2 capture: pre-combustion capture, post-combustion capture, and oxy-fuel combustion. Once captured, the CO2 emissions then need to be transported to a safe site for storage. The transportation is usually done by similar technologies used for transporting natural gas and oil. After being transported to the storage site, the CO2 gas undergoes a few structural changes before reaching its most stable state for storage. Since CO2 becomes less mobile as it is stored longer, the risk of leakage reduces over time.[49]

Globally, there are 18 large-scale CCS facilities in operation, five under construction (all expected to be operational by 2020), and 20 in the development stage.[50] Of the 18 operational large-scale CCS facilities, three are located in Canada, with two facilities in Alberta and one in Saskatchewan. The Quest project, with capture capacity of 1 metric tonne per annum (Mtpa), started operating in 2015 near Edmonton. It captures CO2 from oilsands upgraders and transports it 65 km north for permanent storage approximately two km underground.[51] The newest project, the Alberta Carbon Truck Line (ACTL), is scheduled to be operational later this year and has a larger capture capacity of 1.7 Mtpa. The ACTL will take CO2 from a local refinery and fertilizer plant and transport it 240 km through a pipeline to an Enhanced Oil Recovery (EOR) project in central Alberta.[52]

Current examples of CCS in Alberta show that the technology is technically feasible. The cost of the technology along with environmental policy will play a major role in determining the amount of new CCS projects that develop in the future.

[49] http://www.ccsassociation.org/what-is-ccs/

[50] https://www.globalccsinstitute.com/resources/global-status-report/

[51] https://www.alberta.ca/carbon-capture-and-storage.aspx

[52] https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/snpsht/2019/01-05crbncptr-eng.html

## TECHNOLOGY AND TRENDS

### Small Household Storage

Home energy storage devices are essentially batteries that store electricity for household usage. They can be paired with solar panels to self-generate power independent of the electrical grid. These devices are especially useful and economical for remote households that may be off-grid. Some battery designs allow users to send energy that they have not consumed back to the grid to gain credits on their utility bills.[53] In addition, wide installation of these devices could increase grid flexibility and relieve load during peak hours.

The technology behind home energy storage devices is relatively simple. Most of them use lithium-ion batteries because their recharge cycle is high and self-discharge is low. Some of the mainstream home batteries include Tesla's Powerwall, Panasonic's Tabuchi, and recycled electric vehicle batteries from automobile companies such as Nissan and BMW. These home batteries typically have storage capacity around 10 to 20 kWh and are scalable to meet the specific demand of different households. To provide some context, the average three-bedroom house uses about 30 kWh of energy per day.[54]

### Smart Meters

Traditional electromechanical meters simply record the amount of electricity consumed, and they usually require manual reporting by users or meter readers from utility companies. In contrast, digital smart meters provide much more convenience, transparency and flexibility in managing energy consumption. They continuously send out consumption and billing data back to utilities and allow users to easily check their energy usage on mobile devices or online. These features are designed to save electricity expenses for customers since manual reporting is no longer required. In addition, customers can adjust their energy consumption once they are more aware of their energy usage pattern. Smart meters are also important base infrastructure for developing smart grids.[55]

Most developed countries have initiatives to push for wide installation of smart meters. In the U.S., smart meter coverage has already reached nearly 50 per cent in 2016. Though a specific coverage number is not available for Canada, almost all provinces and territories have plans to increase smart meter coverage, and Ontario has replaced most of its traditional meters already.[56] Major electricity retailers in Alberta such as EPCOR Power also announced their intention to replace almost all of their existing meters with smart meters in the coming years.[57]

### Smart Grid

The boom in big data and interconnected communication networks has sparked tremendous interest in power systems. The driver for integrating intelligence into the traditional power grid is the potential for efficiency gains within the existing utilities management model. Smooth operation of the traditional power grid is challenged by increasing renewable energy penetration as well as increasing numbers of electric vehicles and energy storage facilities. These challenges require modern power grids to be flexible in how they dispatch power.

[53] https://www.panasonicsolar.ca/residential

[54] https://www.nspower.ca/en/home/for-my-home/heating-solutions/battery-storage/faqs.aspx

[55] http://www.auditor.on.ca/en/content/annualreports/arreports/en14/311en14.pdf

[56] https://pdfs.semanticscholar.org/9269/4e2d07d2aeea6c1ed45321485b55184bbfcd.pdf

[57] https://www.cbc.ca/news/canada/edmonton/are-epcor-smart-meters-too-smart-edmonton-customer-raises-privacy-concerns-1.3832266

The major difference between smart grid and traditional power grid operation is the concept of bidirectional power and information flow, meaning that instead of having supply following demand, the grid is able to manage both in real time. Other key features of a smart grid include advanced metering, automated distribution, use of big data analytics, and highly optimized control systems.[58] In the future, we could expect to see a highly automated power grid which enables the near-instantaneous balance of supply and demand at the device level through monitoring and communications of real-time information.[59]

The development of a smart grid requires the implementation of both hard and soft infrastructure. Some of the essential hard infrastructure includes smart meters, transmission and distribution enhancements, distributed energy storage, and smart household appliances. Soft infrastructure includes constructing industrial standards, educating customers, adjusting business models, and developing stakeholder agreements.[60] Many ongoing studies are investigating the specific technology needed and possibilities of implementing large-scale smart grids.

A fully interconnected, large-scale smart grid has not yet been established; however, many smart-grid related initiatives and programs such as smart meters, micro-grids, and vehicle-to-grid systems have been launched to facilitate their development. In Canada, Ontario is leading the development of a smart grid by installing more than 3.4 million smart meters and implementing Time-of-Use (TOU) pricing.[61] A smart grid project known as SPEEDIER at Parry Sound, Ontario recently received $2.9 million of investment from the federal government. This project aims to enable Parry Sound to generate as much energy as it consumes, eventually becoming one of the first net-zero communities in Canada.[62]

In Alberta, the deployment of smart grid related technology is mainly carried out by the system operator, transmission companies, and distribution system owners. The AESO has implemented operator decision support tools and short-term wind forecasting, which together facilitate wind integration. In addition, the AESO is working to establish regulatory policies for energy storage facilities to be integrated into the existing power grid.[63] AltaLink LP has installed a Dynamic Thermal Line Rating (DTLR) system on its transmission lines between the Peigan and Pincher Creek substations, where a large amount of wind generation is transmitted. These transmission lines can become congested under certain operating conditions and the DTLR technology helps to maximize their operational efficiency by determining their capability to transmit electricity in real time.[64] Other smart grid related projects are also being proposed, including EPCOR's solar farm project in southwest Edmonton. This solar farm will be incorporated with a battery energy storage component and intelligent controls and monitoring systems to complete the smart grid set-up.[65]

58 http://www.sgcanada.org/what-is-smartgrid

59 https://www.energy.gov/sites/prod/files/oeprod/DocumentsandMedia/DOE_SG_Book_Single_Pages.pdf

60 https://electricity.ca/wp-content/uploads/2017/05/SmartGridpaperEN.pdf

61 https://www.eia.gov/analysis/studies/electricity/pdf/intl_sg.pdf

62 https://www.newswire.ca/news-releases/modernized-electric-grid-coming-to-parry-sound-890601170.html

63 https://www.aeso.ca/assets/Uploads/Appendix-Q-Energy-Storage-Integration-Recommendation-Paper-and-Stakeholder-Comments.pdf

64 https://www.smartgrid.gov/files/Alberta_Utilities_Commission_Smart_Grid_Inquiry_Final_Report_201107.pdf

65 https://edmontonjournal.com/news/local-news/more-power-to-epcors-proposed-solar-farm-cash-from-feds-and-province


# Appendix D: Glossary

## GLOSSARY

**Alberta Internal Load (AIL):** The total electricity consumption within the province of Alberta, including behind-the-fence (BTF) load, the City of Medicine Hat and losses (transmission and distribution).

**Baseload generation:** Generation capacity normally operated to serve load on an around-the-clock basis.

**Biomass:** Organic matter that is used to produce synthetic fuels or is burned in its natural state to produce energy. Biomass fuels include wood waste, peat, manure, grain byproducts and food processing wastes.

**Brownfield:** Land previously or currently used for industrial or certain commercial purposes.

**Capability:** The maximum load that a generating unit, generating station or other electrical apparatus can carry under specified conditions for a given time period without exceeding limits of temperature and stress.

**Cofiring:** The combustion of two or more different types of fuels.

**Emission offset:** A financial instrument representing a reduction in greenhouse gas (GHG) emissions.

**Feedstock:** Material used to supply or fuel a machine or industrial process.

**Cogeneration:** The simultaneous production of electricity and another form of useful thermal energy used for industrial, commercial, heating or cooling purposes.

**Combined-cycle:** A system in which a gas turbine generates electricity and the waste heat is used to create steam to generate additional electricity using a steam turbine.

**Demand (electric):** The volume of electric energy delivered to or by a system, part of a system, or piece of equipment at a given instant or averaged over any designated period of time.

**Dispatch:** The process by which a system operator directs the real-time operation of a supplier or a purchaser to cause a specified amount of electric energy to be provided to, or taken off, the system.

**Distributed energy resources (DER):** Small-scale power sources typically connected to a distribution system at customer locations.

**Emission intensity:** The ratio of a specific emission (such as carbon dioxide) to a measure of energy output. For the electricity sector, emission intensity is usually expressed as emissions per megawatt hour (MWh) of electricity generated.

**Generating unit:** Any combination of an electrical generator physically connected to reactor(s), boiler(s), combustion or wind turbine(s) or other prime mover(s) and operated together to produce electric power.

**Geothermal energy:** Where the prime mover is a turbine driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids beneath the surface of the Earth.

**Gigawatt (GW):** One billion watts.

**Gigawatt hour (GWh):** One billion watt hours.

**Greenfield:** Land being considered for development that has not previously been used for commercial or industrial purposes.

**Greenhouse gas (GHG) emissions:** Gases that trap the heat of the sun in the Earth's atmosphere, producing a greenhouse effect.

**Grid:** A system of interconnected power lines and generators that is operated as a unified whole to supply customers at various locations. Also known as a transmission system.

**Independent system operator (ISO):** A system and market operator that is independent of other market interests. In Alberta the entity that fulfils this role is the Alberta Electric System Operator.

**kilowatt (kW):** one thousand watts.

**kilowatt hour (kWh):** one thousand watt hours.

**Levelized cost of energy (LCOE):** The average cost per megawatt hour of energy to recover all capital and operating costs, including a specified rate of return, over the entire life of a power generation project.

**Load (electric):** The electric power used by devices connected to an electric system.

**Megawatt (MW):** One million watts.

**Megawatt hour (MWh):** One million watt hours.

Peak load: The maximum power demand (load) registered by a customer or a group of customers or a system in a stated time period. The value may be the maximum instantaneous load or, more usually, the average load over a designated interval of time such as one hour, and is normally stated in kilowatts or megawatts.

**Point-of-delivery (POD):** Point(s) for interconnection on the transmission facility owner's (TFO) system where capacity and/or energy is made available to the end-use customer.

**Reserve margin:** The percentage of installed capacity exceeding the expected peak demand during a specified period.

**Simple-cycle:** Where a gas turbine is the prime mover in a generation plant, a gas turbine consisting typically of one or more combustion chambers where liquid or gaseous fuel is burned. The hot gases are passed to the turbine where they expand, driving the turbine that in turn drives the generator.

**Solar photovoltaic (PV):** A technology that converts sunlight into electricity using semiconductors.

**Solar (power):** A process that produces electricity by converting solar radiation into electricity or to thermal energy to produce steam to drive a turbine.

**Tariff (transmission):** The terms and conditions under which transmission services are provided, including the rates or charges that users must pay.

**Transmission:** The transfer of electricity over a group of interconnected lines and associated equipment, between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems.

**Transmission system (electric):** An interconnected group of electric transmission lines and associated equipment for moving or transferring electricity in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers, or is delivered to other electric systems.

**Watt:** The unit of power equal to one joule of energy per second. It measures a rate of energy conversion.

**Watt hour (Wh):** An electrical energy unit of measure equal to one watt of power supplied to or taken from an electric circuit steadily for one hour.


# Appendix E:
# Errata

# Errata

On September 30, 2019 the AESO posted the *2019 Long-term Outlook* on *www.aeso.ca*. The following corrections reflect immaterial changes that were subsequently identified. The document was updated and reposted on October 17, 2019.

| Description | Page | Section |
|---|---|---|
| Changed “government, policies” to “government policies” in the fourth paragraph of the Executive Summary | 1 | 1.0 |
| Removed (t) after “420 tonnes” from the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations section | 11 | 3.2.1 |
| Clarified language in the first paragraph of the Technology Innovation and Emissions Reduction Program and the Alberta Emissions Offset System section | 12 | 3.2.2 |
| Clarified language in the first paragraph of the 2019 LTO Reference Case Scenario section | 16 | 4.0 |
| Corrected forecast of new generation capacity from 12 GW to 13 GW in the Reference Case Generation Results section | 23 | 4.2.3 |
| Clarified language in the High Cogeneration Sensitivity Assumptions section | 23 | 4.2.4 |
| Corrected generation capacity in the Central Planning Region from 2,641 MW to 2,635 MW and clarified language in the Generation section | 29 | 5.3 |
| Corrected generation capacity in the Northwest Planning Region from 1,003 MW to 988 MW in the Generation section | 31 | 5.4 |
| Clarified language in the second paragraph of the Generation section for the Northeast Planning Region | 33 | 5.5 |
| Corrected wind capacity from 5,300 MW to 5,900 MW in the Alternate Renewable Policy Scenario Generation Assumptions section | 36 | 6.1.2 |
| Corrected wind capacity additions from 6,800 MW to 5,900 MW in the Alternate Renewable Policy Scenario Generation Results section | 37 | 6.1.3 |
| Corrected cogeneration development from 2,295 MW to 2,362 MW in the High Growth Scenario Generation Assumptions section | 39 | 6.2.4 |
| Corrected the legend in Figure 13 to reference the Low Growth Scenario instead of the High Growth Scenario | 41 | 6.3.1 |
| Corrected cogeneration development from 90 MW to 157 MW in the Low Growth Scenario Generation Assumptions section | 42 | 6.3.4 |
| Corrected the approximate increase in solar capacity from 700 MW to 2,700 MW in the Diversification Scenario Generation Results section | 47 | 6.4.5 |
| Clarified the heading in Table 1 to indicate LCOE cost assumptions are in 2020 dollars | 50 | Appendix A |
| Added “Appendix D:” to the Glossary cover page | | Appendix D |
| Added new cover page for Appendix E: Errata | | Appendix E |
| Added table of changes since original publication date of Sept. 30, 2019 | 76 | Errata |

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