AESO 2020 Long-term Transmission Plan

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Executive summary

The 2020 Long-term Transmission Plan (2020 LTP) describes how the Alberta Electric System Operator (AESO) plans to develop Alberta's electricity transmission system over the next 20 years.

The Long-term Transmission Plan (LTP) is the AESO's 20-year forward-looking blueprint of how the transmission system needs to be developed to support continued economic growth in Alberta. Updated every two years, the LTP provides for a safe and reliable electricity system that enables a fair, efficient and openly competitive electricity market, which is key to the economic well-being and continued prosperity of Alberta.

Consistent with global trends, Alberta's electricity industry is in a state of transformation, due in part to evolving technology, policies, and social and economic drivers that affect future generation development and load growth. The diversity of the province's fuel sources is also evolving. Historically, coal was Alberta's primary fuel source, providing on-demand generation through the bulk transmission 240 kilovolt (kV) network. The fuel source profile and transmission system began to change due to growth of the oil and gas industry, with the oil sands sector contributing significantly to both load and generation. With coal retirement on the horizon through to 2030, transmission planning and development must continue to evolve, accommodating potential conversions of coal to gas facilities and the prospective development of wind and solar resources.

The 2020 LTP seeks to optimize the use of the existing transmission system, and plan development of new transmission in a timely manner to provide for the safe, dependable and efficient delivery of electricity across Alberta, wherever and whenever it is needed. Recognizing that the electricity industry has entered a transformational change, the AESO has continued to evolve its approach to planning. This is reflected in the use of broad scenarios in the planning process to identify potential, yet flexible, transmission system upgrades within this 2020 LTP. The *AESO 2019 Long-term Outlook* (2019 LTO), which serves as the basis for the 2020 LTP, utilizes five scenarios to forecast the range of potential future states associated with evolving policies, technologies, fuel sources, and social and economic drivers in Alberta.

In June 2018, the AESO published a *Transmission Capability Assessment for Renewables Integration* (2018 Capability Assessment) as an update to the Renewables Generation Integration Plan section of the 2017 LTP. The 2018 Capability Assessment determined the capability of the existing transmission system to integrate renewables generation within central east and southern Alberta, and included the projects selected in Round 1 of the Renewable Electricity Program (REP).

An update was completed in 2019 as the REP Rounds 2 and 3 progressed. These capability assessments are useful indicators for current and prospective market participants, providing direction on where capability is available and optimal areas to situate projects to connect to the system. When investors and market participants site new generation close to existing and planned infrastructure, it supports effective utilization of transmission infrastructure, which is beneficial to both the AESO and its stakeholders.

The AESO is committed to ensuring that all forms of generation–regardless of location or type–can be reliably connected to the transmission system. With capability assessments completed for the central east and southern areas of Alberta, additional assessments for generation integration in the Northeast, Northwest and Edmonton Planning Regions were completed for the 2020 LTP.

The 2020 LTP provides guidance related to the pace and type of transmission developments anticipated in the future, and takes into account how forecasting inputs may impact need and timing. All transmission projects identified in the 2020 LTP will undergo further review prior to progressing towards implementation, and are subject to change based on new information that may become available. Through this approach, the AESO will adjust planned transmission projects as required, and will be prepared for a wide variety of economic and electric system changes that Alberta may face in the future.

Since mid-2014, the outlook for economic growth within the province has been revised downward, primarily in response to changes in the price outlook for crude oil. The downward revision of oil prices and economic growth for Alberta is consistent with industry outlook, and results in lower load growth than anticipated in previous AESO LTPs.

A complementary integration capability interactive map featuring 240 kV transmission lines and substations, as well as the location of projects selected for the REP, was introduced with the publication of the first *Transmission Capability Assessment for Renewables Integration*.

View the *Optimal Integration Capability Interactive Map* at: **www.aeso.ca/grid/ltp/capability**

The five scenarios from the 2019 LTO that are studied in the 2020 LTP include:

- **Reference Case**–aligns with the most recent information pertaining to Alberta's electricity framework and governing policies, and serves as the AESO's base case to plan the system in the near term (five-year horizon up to 2024), and one of the scenarios for the longer term (five+ years).
- **High Cogeneration Sensitivity**–assesses the long-term transmission needs associated with rapid cogeneration additions in the Fort McMurray area to support oil sands efficiency and emission reduction gains.
- **Alternate Renewables Policy**–represents a faster pace of renewables development on both the transmission and distribution networks, compared to the Reference Case.
- **High Load Growth**–provides the basis to pressure test the transmission plans developed under stronger economic growth that leads to higher load in the longer-term planning horizons; specifically, this scenario reflects stronger growth in oil and gas development activities.
- **Low Load Growth**–assumes load grows at a slower pace than anticipated under the Reference Case. This scenario is intended to capture and reflect the impacts of higher adoption rates of behind-the-fence (BTF) generation and higher concentrations of distributed energy resources (DER) in urban areas, such as rooftop solar systems. The impact on the transmission system as a result of the slower pace of growth is investigated.

Using different scenarios allows for the development of a resilient, yet flexible, long-term transmission plan. The 2020 LTP ensures the transmission network in Alberta remains reliable, with planned developments that cover various scenarios, while at the same time is designed to adjust quickly should material shifts in need occur.

The 2020 LTP satisfies the AESO's mandate as stated in the province's *Electric Utilities Act (EUA)* and *Transmission Regulation (T-Reg)*. By maintaining flexibility in its planning, the AESO is well-positioned to adapt to shifts in Alberta's load and generation needs. Whenever appropriate, the 2020 LTP considers the use of milestones to trigger the construction of approved transmission projects only as existing transmission system capability is utilized. This will assist in managing forecast uncertainty of future generation developments, and allow the AESO to ensure the timing of transmission infrastructure developments align with committed generation development plans, providing confidence to attract needed investment in Alberta.

1.1 2020 LTP HIGHLIGHTS

- The 2020 LTP identifies 20 transmission developments proposed over the next five years valued at approximately $1.4 billion. Each of these developments will require detailed needs analysis and regulatory approvals prior to proceeding. Overall, these developments are estimated to increase average transmission rates by about $0.50—$0.70 per megawatt hour, starting in 2025.

Generation integration plans

Northern Regions

With all coal-fired generation expected to retire by 2030, new conventional gas-fired generation is expected to replace Alberta's existing coal fleet capacity. As part of the 2020 LTP, the AESO performed integration capability assessments for conventional generation in areas where the utilization of existing transmission infrastructure offers an advantage. The capability assessments were informed by developer interest and active projects in the AESO project list. The studies are intended to provide guidance to generation developers to identify the areas with existing and planned transmission system capability, as well as to assess system reliability needs in the short and long term. The capability studies focused on the Northeast, Northwest, and Edmonton Planning Regions, as these areas are rich in natural gas resources and are traditionally where significant conventional generation development has taken place.

The existing bulk transmission system was found to be capable of integrating new conventional generation, especially at or close to brownfield sites. The areas with available transmission integration capability include Wabamun Lake in the Edmonton Planning Region, where a maximum of approximately 2,400 megawatts (MW) of conventional gas-fired generation can be accommodated in conjunction with the area's existing coal-fired generation. Main 240 kV substations in the northwest, including the Bickerdike substation near Edson, are capable of accommodating between approximately 100 MW to 1,000 MW of conventional generation. With Fox Creek area developments in place, the Bickerdike substation can accommodate approximately 300 MW, and the Sagitawah substation (near the Whitecourt substation) can accommodate approximately 1,150 MW.

In the Fort McMurray area, there is sufficient transmission system capability to integrate further oil sands development. From a cogeneration perspective, the system (with the Fort McMurray West [FMW] line) is currently capable of integrating approximately 500 MW of additional conventional generation. Approximately 300 MW of additional integration capability could be enabled by a 240 kV system upgrade in the area, bringing the total generation integration capability to approximately 800 MW. Alternatively, the Fort McMurray East (FME) 500 kV transmission line would increase the transmission system capability to approximately 1,800 MW. The planning assessments confirmed the need for the FME line in the High Cogeneration Scenario, which could be advanced to an earlier timeframe depending on the pace of cogeneration developments.

In areas of high renewables development potential where conventional generation can also develop—mainly the southwest, southeast and central east areas of the province—renewables capability assessments define existing and planned transmission system generation integration capability. However, the transmission system capability to integrate conventional generation in these areas could be slightly lower than those estimated for renewables due to coincident higher generation dispatch levels of existing thermal assets.

Central and Southern Regions

The 2020 LTP considers two different paces of renewables development. Under the Alternate Renewables Policy Scenario, there are more renewables connecting to the grid. To enable these anticipated renewables, the AESO developed a staged plan based on milestones. First, the Provost-to-Edgerton and Nilrem-to-Vermilion (PENV) Transmission Development, approved in 2019, is expected to provide approximately 350 MW of additional renewables integration capability.

The Central East Transfer-out (CETO) and Chapel Rock-to-Pincher Creek (CRPC) Transmission Developments are the most effective projects to integrate renewables generation in central east and southwest Alberta. The CETO development is expected to enable approximately 700 MW of renewables. In the southwest, CRPC is expected to enable approximately 600 MW of renewables generation. Depending on the pace and location of renewables developments, each project will have associated milestones to trigger project construction once the renewables projects themselves reach a stage of certainty to proceed. Other projects were investigated to further enable renewables integration. CRPC and CETO were confirmed to offer the best value in terms of incremental renewables integration capability versus associated costs and impacts.

Distributed energy resources

Currently, there are approximately 500 MW of DER connected to the Alberta electric system. With this level of DER capacity, the AESO is confident the existing requirements and practices allow for the management of transmission system reliability. However, as additional DER develop, especially in the urban areas, the technical requirements and standards will have to evolve to support continued reliable integration without negative impacts to the transmission system.

The AESO investigated the integration of up to 300 MW of additional DER in major urban areas, which reflects an approximate saturation level of solar resources in those areas. The assessment revealed that transmission system capability to integrate renewables in the south and central east is reduced by approximately 60 MW for every 100 MW of DER integrated in the City of Calgary, and by approximately 100 MW or higher for every 100 MW of DER integrated in the southwest, southeast and central east areas of the province. The integration of moderate DER in the cities of Red Deer and Edmonton will not reduce transmission system integration capability.

Distributed Energy Resources (DER) are small physical and virtual devices that are deployed and connected across the grid or distribution system. DER systems are decentralized and flexible technologies, typically close to the load they serve, and usually behind the meter. They can be used individually or in aggregate to provide value to the grid, individual customers, or both.

Near-term regional transmission plan highlights

The following regional highlights summarize potential transmission system developments needed over the next five years:

- **Northwest Planning Region**
  - 240 kV transmission enhancement in the Fox Creek area to address transfer-in constraints and reinforce local supply.
  - 144 kV transmission line and voltage support devices in the Grande Prairie/Grande Cache area to address local area supply.
- **Northeast Planning Region**
  - Additional voltage support device in the Fort McMurray area.
- **Edmonton Planning Region**
  - Transmission enhancement in the City of Edmonton's 72 kV system to maintain reliable long-term supply within the city.
  - Additional 500/240 kV transformation capacity to provide additional flexibility in the bulk transmission system in the region.
- **Central Planning Region**
  - 240 kV transmission line to increase transfer-out capability to integrate additional generation.
  - Additional voltage support devices at three locations within the region.
- **South Planning Region**
  - 500 kV Chapel Rock substation, 240 kV transmission line and a voltage support device to increase transfer-out capability to integrate additional generation and help restore the Alberta—British Columbia (B.C.) intertie.
  - Additional transmission enhancements to help restore the Alberta—B.C. intertie to its original path rating.
  - Expansion of the existing Tilley substation near Brooks to 240 kV operation to reinforce local load supply.
  - Additional voltage support devices at two locations within the region, as well as additional transmission reinforcements near Lethbridge.
- **Calgary Planning Region**
  - Short-circuit mitigation for the City of Calgary.
  - 138 kV transmission line near Chestermere to reinforce local load supply.

Longer-term system plans

The following scenario-based highlights summarize potential transmission system developments required for the longer term.

- **Reference Case**
  - Additional 240 kV transmission line and upgrade of existing lines in the Central Planning Region to further increase system capability to integrate additional generation.
  - Back-to-back high-voltage direct current (HVDC) converter for the Montana—Alberta Tie Line (MATL) to completely restore the Alberta—B.C. intertie to its original path rating.
  - Additional 500 kV or 240 kV developments in the Edmonton Planning Region to enhance the bulk transmission system.
- **Alternate Renewables Policy (Faster-Pace Renewables)**
  - Inclusion of Reference Case developments.
  - Eastern Alberta Transmission Line (EATL) conversion to bi-pole operation for additional transfer capability.
- **High Load Growth**
  - Inclusion of Reference Case developments.
  - Additional 240 kV developments in the Northwest Planning Region to reinforce local load supply.
- **High Cogeneration**
  - Inclusion of Reference Case developments.
  - Development of the approved 500 kV FME transmission line and 240 kV transmission line upgrade in the Northeast Planning Region to increase system capability for Fort McMurray to integrate additional cogeneration.

2.0 Background and objectives

Background and objectives

The AESO works with industry partners to keep electricity flowing throughout the province. Our system controllers balance supply and demand 24/7, ensuring four million Albertans have power when and where they need it.

The AESO is required by provincial legislation to operate the transmission system in a safe, reliable and economic manner and plan a transmission network that meets electricity demand today and in the future. It is governed by an independent board comprising nine members appointed by the Minister of Energy. Following the principles of sound governance, the AESO balances the interests of a wide range of stakeholders in order to fulfil its legislative mandate.

The AESO's duties and responsibilities related to transmission planning are prescribed in the Province of Alberta's *EUA* and *T-Reg.*

These duties include the following:

- Determine future requirements of the provincial grid, identify transmission system enhancements needed to meet those requirements, and arrange to implement those enhancements in a timely and efficient manner and in accordance with statutory obligations.
- Prepare and maintain a transmission system plan that forecasts, on a 20-year horizon, system conditions and requirements to accommodate future load growth and anticipated generation additions.
- Direct the safe, reliable and economic operation of the interconnected electric system.
- Operate the power pool and facilitate the electricity market in a manner that is fair, efficient and openly competitive.
- Provide transmission access service consistent with an approved transmission tariff.
- Manage and recover the costs associated with line losses and ancillary services.
- Conduct a fair and open competitive process to determine the successful proponent who will develop, design, build, finance, own, operate, and maintain identified major transmission infrastructure in Alberta.

The AESO's transmission system planners and economists analyze provincial electricity consumption patterns using data from a variety of sources to determine where electricity demand is likely to grow. The AESO also forecasts the type, capacity and location of generation anticipated to efficiently meet electricity demand, enable the coal-fired generation phase-out, and integrate renewables generation across a range of scenarios to determine potential new transmission infrastructure that may be required.

The 2020 LTP further takes into consideration the following:

- Technical considerations, reliability standards and operating criteria that provide for system reliability and a well-functioning market.
- Key milestones fundamental to transmission development projects, including planned need dates and staging of developments to allow for flexibility.
- Feedback provided through transmission-connected customers, market participants, municipalities and other stakeholders.

The objective of the 2020 LTP is to present the AESO's vision of how Alberta's electric transmission system needs to be developed to support Alberta's economic and energy outlook over the next 20 years, and identifies the necessary developments to meet the need of emerging changes.

The 2020 LTP is designed to:

- Ensure the transmission system's ability to accommodate short- and long-term growth and to ensure continued reliability.
- Enable new technological advancement and more efficient use of energy, such as the development of DER in urban areas and energy storage facilities.
- Enable efficient renewables development in Alberta, in consideration of a potentially faster pace of development based on economics, policy, and other factors.
- Identify where existing transmission system capability is available and planned, providing direction to facilitate the efficient use of the transmission system and to ensure timely and economic resource development.
- Support and enable Alberta's economic recovery.
- Satisfy the AESO's mandate according to the *EUA* and *T-Reg* to provide an update every two years, and file it for information with the provincial Minister of Energy and the Alberta Utilities Commission (AUC).

2.1 STAKEHOLDER CONSULTATION AND ENGAGEMENT

The AESO engages Albertans across the province to develop the transmission system. This consultation process provides the AESO with a broad perspective and valuable input that is then used to assist in establishing forecast scenarios and corresponding transmission planning results.

Over the past year, the AESO conducted targeted LTP consultation and information sessions with transmission facility owners (TFOs), distribution facility owners (DFOs), industry associations, and specific regional municipalities. Additional information and feedback on the LTP was obtained by AESO representatives who were engaging with landowners and other stakeholders on transmission development projects through Participant Involvement Programs for Needs Identification Document (NID) Applications.

The AESO recognizes that stakeholder experience and expertise helps to improve the quality and implementation of decisions on the LTP, as well as a range of other regulatory issues, such as market rules and the tariff. In late 2019, the AESO introduced a draft *Stakeholder Engagement Framework*, which was developed to guide the AESO's engagement approach. Stakeholder feedback is being solicited to ensure the approach continues to allow their needs and interests to be consistently, transparently and meaningfully considered.

2.2 ECONOMIC, SOCIAL AND ENVIRONMENTAL CONSIDERATIONS

Public interest and the effects of transmission developments—from economic, environmental and social perspectives—are primary considerations in the planning, design, construction, location and operation of transmission infrastructure. Identified early in the planning process, these considerations are further assessed as a transmission development plan progresses through the AESO's NID Application process, and are evaluated during AUC regulatory proceedings.

The AESO is not directly responsible for the detailed siting and routing of transmission developments. This process falls to TFOs and the AUC. However, the AESO does consider a variety of factors when preparing a NID Application, including high-level landowner, visual and environmental impacts.

When carrying out its mandate, the AESO is required by Section 16.1 of the *EUA* to act in accordance with applicable *Alberta Land Stewardship Act* (ALSA) plans. When project needs dictate, the AESO participates in ALSA regional planning activities as part of its regional planning, and takes the objectives and outcomes of applicable ALSA regional plans into account.

> The decisions the AESO makes help to shape Alberta's economic prosperity; stakeholder feedback is a key part of the processes that the AESO undertakes to reach decisions.

3.0 Forecast process and methodology

Forecast process and methodology

Alberta's competitive electricity market determines investment in generation; the LTO provides a view of what generation is expected to develop to meet forecast demand and ensure a reliable supply of power now and in the future.

The AESO's most recent forecast, the 2019 LTO, was published in September 2019 and is a key input for the 2020 LTP. The 2019 LTO is the source for load and generation forecasts across several scenarios. Key elements of the 2019 LTO are outlined in this section. For additional information, please refer to the document at *www.aeso.ca/grid/forecasting.*

The 2019 LTO was developed during a period of uncertainty and 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 understand the effect of alternate potential outcomes, the AESO developed a series of scenarios in addition to its main corporate outlook.

The 2019 LTO is robust and comprehensive, and designed to align with current and expected trends. The following actions were undertaken in developing the plan:

- The most up-to-date information and best practices in forecasting methodology and tools were utilized.
- Third-party information was incorporated and validated against other credible forecasts whenever possible.
- Econometric models and market simulation were utilized to assist in forecasting future generation.
- Information was gathered, assumptions were confirmed, and outlooks were aligned through consultation with stakeholders, including industry groups, generation developers and DFOs.
- The province's largest source of electricity industry expertise—our own employees—were consulted.
- New technologies and industries that have recently started impacting Alberta's electricity demand were considered.

Load

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, i.e., point-of-delivery (POD), areas, regions, and the whole province, and uses historic load and input variables such as real Gross Domestic Product (GDP), population, employment, oil sands production, temperature, time of day, time of week, and time of year. The forecast includes the economic variables outlook, and the weather profile for the 90th percentile of the past 10 years of historical weather.

A reconciliation process is carried out to ensure that the POD, area and regional forecasts add up to the Alberta Internal Load (AIL) forecast. The econometric modelling and the locational reconciliation process in the 2019 LTO is an improvement from previous LTOs. POD forecasts rely on economic inputs to forecast load and the reconciliation process adjusts POD, area and regional forecasts based on the relative size of each site. New load modifiers that capture new load behaviors not apparent in the historical data are then layered on top of the reconciled output.

Generation

The LTO generation forecast is premised on sufficient generation capacity being developed to reliably meet demand. Generation in Alberta is developing through competitive market forces, and 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 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 fundamental drivers such as demand, fuel prices and renewables generation profiles.

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 that developers take into account when making investment decisions.

3.1 FORECAST SCENARIOS

The 2019 LTO utilized a set of scenarios to evaluate transmission system capability and potential expansion needs over the next 20 years. Following is a summary of the scenarios utilized in the 2020 LTP.

Reference Case

The 2019 LTO Reference Case was applied as the base case for both the near-term and longer-term 2020 LTP assessments; differences between the scenarios are immaterial in the near term.

The Reference Case is consistent with information available at the time of the 2019 LTO's development, including announcements made by the Government of Alberta, the Government of Canada and market participants.

Key Assumptions

Load

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 oil sands, residential and commercial load.

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 oil sands and improved efficiency in residential, commercial and non-industrial sectors. The overall impact of these energy efficiency improvements result in a 1.7 per cent or 251 MW decrease in winter peak by 2039, compared to no energy efficiency applied to the forecast.

Generation

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

Renewables generation development

The Reference Case assumes that the level of renewables development is based on known policy-supported projects, including the REP Rounds 1, 2 and 3, Alberta Infrastructure support for solar, and development by additional market-driven investments.

Coal retirements and conversions to gas

The Reference Case assumes that all of the approximately 5,275 MW of coal-fired capacity will be converted to natural gas-fired generation, beginning in the year 2021. These are assumed to operate as coal-to-gas 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.

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 5,574 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 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

For the purposes of transmission system planning and to fulfill the requirements of the *EUA* and *T-Reg:*

- Locations are assumed for future generation.
- Generation technologies are 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 system 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 renewables generation stated within the 2019 LTO represent a reasonable assumption, based on where the best potential resources are available.

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 developments are primarily assumed to occur within the established oil sands 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.

Forecast outcomes

Load

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

The Reference Case load forecast for the 2019 LTO is moderately higher than the 2017 LTO Reference Case in the near term. This increase is due to a higher oil sands 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.

Generation

A forecast of installed generation capacity was developed based on the 2019 LTO assumptions and methodology. In total, 13 gigawatts 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. Renewables development occurs in the near term from the REP Rounds 1, 2, and 3, and developments afterward are driven by market-based investment. 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, Load and Generation Scenarios, including regional data, can be found within the 2019 LTO and 2019 LTO data file available at *www.aeso.ca/grid/forecasting.*

High Cogeneration Sensitivity

Cogeneration development decisions will continue to be dynamic, with oil sands emission limits, carbon pricing and the potential need to replace aging steam boilers—all factors in decisions for existing and future cogeneration sites. There are a number of potential cogeneration projects currently under consideration. The High Cogeneration Sensitivity Scenario considers a larger amount of cogeneration developments compared to the Reference Case.

Assumptions

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

Forecast outcomes

In comparison with the Reference Case, the High Cogeneration Sensitivity Scenario results in additional cogeneration development which defers and displaces both renewables and gas-fired capacity. After the final REP projects are in service, wind additions are lower compared to 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.

Alternate Renewables Policy

The Alternate Renewables Policy Scenario provides an outlook for the Alberta generation fleet if it were driven by a renewable-energy target or policy that supports greater renewables 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 energy sources by the year 2030, and a higher carbon price of $30/tonne.

Assumptions

The Alternate Renewables Policy Scenario assumes the same load growth as the Reference Case. The key assumption in this scenario is an increase in the amount of renewables compared to the Reference Case. Assumed government support for renewables continues in line with observed renewables portfolio standards common in other jurisdictions. The additions are weighted to the lowest-cost renewables technology based on current estimates. As such, the main assumption is that wind capacity grows by approximately 5,300 MW over the 20-year forecast period.

Forecast outcomes

The Alternate Renewables Policy Scenario has a large amount of renewables generation compared to the Reference Case. Over 6,800 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.

High Load Growth

The High Load 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 oil sands 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.

Assumptions

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

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 oil sands, the amount of assumed cogeneration growth is increased such that there is 2,295 MW of cogeneration development.

Forecast outcomes

This scenario has a compound annual peak load growth of 1.8 per cent to 2039. The High Load 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.

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 to the Reference Case. The level of renewables additions is assumed to be marginally lower than the Reference Case.

Low Load Growth

The Low Load Growth Scenario tests the impacts of lower load growth corresponding to significantly reduced oil sands 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 photovoltaic (PV) rooftop solar.

Assumptions

This scenario assumes existing and under-construction oil sands 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.

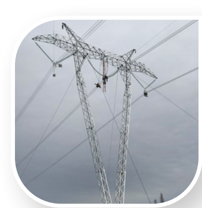
The majority of assumptions in the Low Load Growth Scenario remain the same as the Reference Case. The key difference is that with lower oil sands and load growth, corresponding cogeneration levels are also lower. With decreased growth in the oil sands, the amount of assumed cogeneration growth is reduced such that 90 MW of new cogeneration develops.

Forecast outcomes

The long-run load growth in the Low Load 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. As described in the load assumptions section, the decrease in the load outlook compared to the Reference Case is due to a lower oil sands and economic outlook and an increased energy efficiency assumption.

Due to lower load growth of this scenario in comparison with the Reference Case, less generation develops over the forecast horizon. The Low Load 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 that have received contracts under the REP are assumed to develop, while additional wind development is reduced 50 per cent compared to the Reference Case.

Additional details of the previously described LTO scenarios can be found within the 2019 LTO and 2019 LTO data file available at *www.aeso.ca/grid/forecasting.*



> The retirement of existing coal units over the 20-year forecast period, coupled with an increase in demand, result in the system needing considerable new generation to ensure a reliable supply of power to meet load requirements.

4.0 Transmission planning and developments

Transmission planning and developments

The 2020 LTP is designed to be flexible to accommodate a number of possible scenarios. Transmission developments will be staged using milestones to ensure that transmission facilities are ready and available at the right location and at the right time.

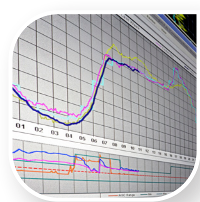
4.1 2020 LTP DEVELOPMENT STRATEGY

The AESO's 2020 LTP development strategy identifies the necessary transmission developments to meet the need of emerging changes, and is intended to be responsive to the needs of market participants, focusing on the following areas:

- Enable new technological advancement and more efficient use of energy, such as the development of DER in urban areas, and integration of energy storage facilities.
- Show where transmission system capability is available and planned, facilitating use of established infrastructure and providing locational signals to ensure timely and efficient resource development.
- Support and enable Alberta's economic growth.

4.2 OVERVIEW OF EXISTING TRANSMISSION SYSTEM

Transmission developments are generally driven by load and generation, as the purpose of the transmission system is to move power from generators to load. The location and density of load, and the size and location of generation, dictate the capacity, location and configuration of the transmission network required to serve the integrated system.



Investors in generation bear the risks of selecting the most cost-effective fuel source, size and location of generation to maximize their competitiveness in the wholesale power market.

Current load and generation profile

The load profile in Alberta is diverse, with a large percentage being comprised of industrial customers, major urban centres, and some sparse rural areas. Rich in oil sands resources, the Fort McMurray area represents a unique feature of industrial load makeup, accounting for approximately one-third of the province's load. The two largest urban centres, Calgary and Edmonton, also account for approximately one-third of the load, with the South, Central and Northwest Planning Regions accounting for the balance of demand. These regions are primarily industrial and agricultural with sparse rural load.

Generation development in Alberta during the mid-to-late 1900s was primarily coal based, with the majority located near Wabamun Lake, Stettler and Hanna. As the oil sands were developed in the Fort McMurray area, a large amount of gas-fired cogeneration was added to support the heating requirements of oil sands processing, while also generating electricity for local consumption and, in many cases, providing surplus electricity to the Alberta grid.

The abundance of natural gas in the province, coupled with low prices, has resulted in the growth of gas-fired generation facilities, the largest of which is the Shepard Energy Centre, an 860 MW combined-cycle facility located in Calgary. Alberta has a relatively small amount of hydroelectric generation (approximately 900 MW), which includes smaller plants on the Bow River and tributaries, as well as the larger Bighorn and Brazeau plants in the North Saskatchewan watershed.

Renewable energy, specifically in the form of wind generation, has grown substantially over the past 10 years to a total of about 1,500 MW in the south and central east areas of the province. Alberta has significant renewable energy resource potential, namely wind and solar, in these areas. Additional wind generation totaling about 1,400 MW was awarded as part of the REP Rounds 1, 2 and 3, with target commercial operation dates between 2019 and 2021.

Existing transmission system

Historically, Alberta's transmission system was developed in response to load growth and generating facilities constructed to meet the need. As coal-fired generation developed in the Wabamun Lake area between the mid-1950s and mid-1990s, transmission infrastructure was needed to connect the generation to major load centres in Calgary and Edmonton. In recent years, oil sands development near Fort McMurray has driven transmission development to—and within—that area. The transmission system has also been enhanced in the south and central east areas to integrate new generation from those renewable-resource rich areas of the province.

Following the AESO's identification of the need for transmission, comprehensive planning and engineering studies present high-level technical alternatives that will address the need. These alternatives are then evaluated, compared and ranked based on their technical, economic, environmental and social merits.

Bulk transmission system

The bulk transmission system consists of 500 kV and 240 kV lines that move large amounts of power from generation sources to load centres (Figure 4.2-1). A 500 kV network located primarily around the Wabamun/Edmonton area serves as a central hub of the Alberta Interconnected Electric System (AIES). This 500 kV network extends east to the Heartland substation in the Fort Saskatchewan area, as well as north to the Thickwood Hills substation in the Fort McMurray area. Two 500 kV HVDC lines connect the north 500 kV bulk system to the south. Near Calgary, the western HVDC line connects to the 240 kV network and the 500 kV intertie with B.C. Near Brooks, the eastern HVDC line connects to the regional 240 kV network. The HVDC lines are able to transfer power in both directions. The 500 kV bulk system is supported by an underlying network of 240 kV lines.

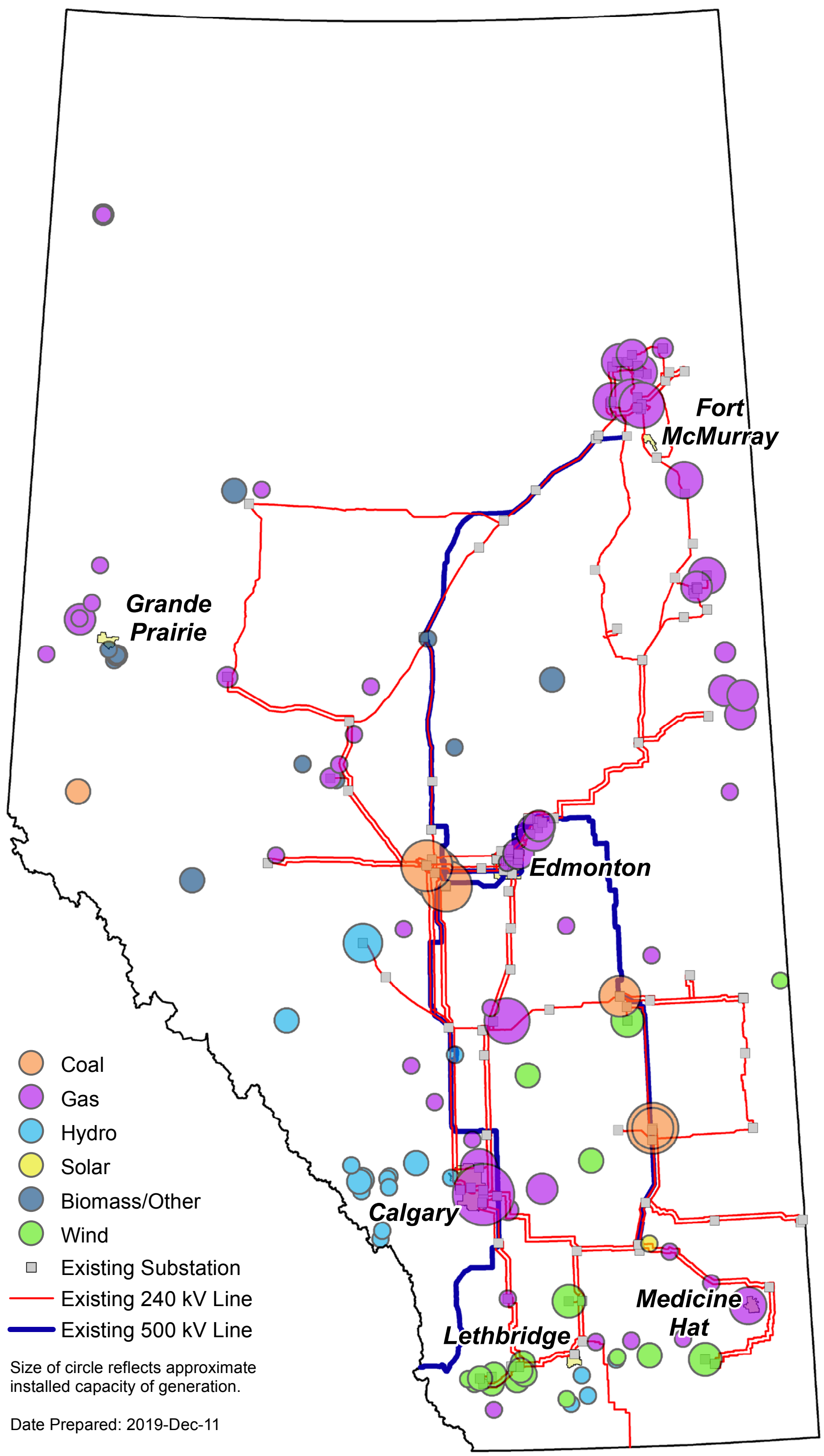
Many components of this bulk transmission system were completed in the past 10 years. These include:

- **FMW 500 kV Transmission Project**–500 kV single circuit transmission line between the Sunnybrook substation in the Wabamun Lake area and the new Thickwood Hills substation southwest of Fort McMurray.
- **Heartland 500 kV Transmission Development**–500 kV double circuit transmission line between the Ellerslie substation and the Heartland substation to strengthen supply into the industrial zone and to the northeast.
- **North-South Transmission Reinforcement**–two 500 kV HVDC lines, EATL and Western Alberta Transmission Line (WATL), connecting the north and south planning areas.
- **South and West of Edmonton**–240 kV and 138 kV transmission system enhancements.
- **Red Deer Area Transmission Development**–240 kV and 138 kV transmission system reinforcements in the Red Deer area.
- **Foothills Area Transmission Development**–240 kV and 138 kV enhancements in and south of Calgary, including a new 240/138 kV substation near High River to accommodate renewables generation in the south, as well as other Calgary area generation.
- **Hanna Region Transmission Development Phase 1**–240 kV and 144 kV transmission developments in the Hanna, Sheerness and Battle River areas.
- **Southern Alberta Transmission Reinforcement (SATR)**–240 kV transmission system reinforcements in southern Alberta to integrate renewables generation.

These reinforcements provide necessary transmission capacity to move power between the major regions and strengthen the bulk transmission system.

Rich in oil sands resources, the Fort McMurray area represents a unique feature of industrial load makeup, accounting for approximately one-third of the province's load. Over the past 10 years, load growth in this area has been the strongest of any region.

Figure 4.2-1: Existing bulk transmission system and existing generation (by size)



Regional transmission systems

Regional transmission systems take power from the bulk transmission system and move it to load-serving substations that serve distribution systems. Major urban centres have concentrated systems comprising several load-serving substations in a relatively small geographic area. In other areas, regional transmission systems can be present in sparsely populated areas such as the south or central parts of the province, where there are significant distances between substations and load.

Interties

As part of the North American electricity grid, Alberta's interconnections with neighbouring systems are an essential component of a reliable transmission system and competitive electricity market. Alberta is one of the least interconnected systems in North America. With the third-largest peak demand for electricity among all provinces in Canada at approximately 11,500 MW, Alberta's simultaneous intertie capability is approximately 10 per cent of our peak demand.

Currently, Alberta is interconnected with neighbouring systems through three paths:

- **B.C. Intertie**–has an existing export capability of 1,000 MW and an import capability of 800 MW.
- **Saskatchewan Intertie**–is capable of transferring approximately 150 MW.
- **Montana Intertie**–is capable of transferring approximately 300 MW.

4.3 TRANSMISSION SYSTEM ASSESSMENTS

The 2020 LTP assesses the system using two different time frames:

- **Near-term assessment (five years):** The purpose of the near-term assessment is to examine the transmission system on a regional basis in detail. The detailed assessment allows the AESO to understand the regional needs for the next five years, resulting in higher-level certainty in load and generation development trends. Transmission development plans identified here are to mitigate violations observed during the assessment. Some of the plans have also been identified in previous LTPs. These plans will still need to undergo further need identification and alternative evaluation for the AESO to determine that a specific project is needed. Only then would the AESO bring the project forward for regulatory approval. Given the time required for these subsequent steps in the planning process, the earliest any of the large projects identified in the near-term plan would be constructed is five years in the future. However, the AESO continues to monitor developments in the system and will prioritize the needed system investments to ensure the system remains reliable.
- **Longer-term assessment (five+ years):** The longer-term assessment examines the transmission system from a bulk, system-wide basis based on a range of future scenarios. It also captures major effects of the various scenarios discussed in the forecast section. As such, only outages on elements at 240 kV and above were assessed, and elements at 138 kV and above were monitored. The longer-term assessment is to provide the framework for which the transmission system could develop in the longer term to allow the AESO to be prepared for all possible future outcomes.

4.4 TELECOMMUNICATION NETWORK PLAN

Alberta's province-wide utility telecommunication network utilized by the electricity system is essential to the reliable, efficient and safe operation of the grid. This sophisticated infrastructure overlays the transmission system and is vital to monitoring, operating and protecting the interconnected electric system and all reporting functions.

The utility telecommunication network carries critical telecommunication services used to protect, monitor and control the transmission system. It helps to quickly isolate faulted elements to maintain system stability, monitor transmission network integrity, protect equipment from unnecessary damage, and allow system operators to respond to changes and take corrective action as needed. Outages on the utility telecommunication network can require outages on the transmission system. These critical services require the telecommunication network to be highly reliable and have appropriate capacity.

The following are key benefits of the utility telecommunication network:

- Enables coordinated monitoring, control and operation of the transmission system.
- Enables larger power flows on transmission lines by facilitating faster fault-clearing times and advanced protection schemes.
- Enables the connection of additional and diverse generation on existing transmission lines.
- Enables the connection of additional load on existing transmission lines.
- Provides emergency voice and data telecommunication for effective power system restoration.

The utility telecommunication network is a private network owned and operated by TFOs. Utility telecommunications need to be highly reliable, available and functional under all and, most importantly, severe operating conditions.

Technology, system evolution and the following technological trends affect the utility telecommunication network:

- Shift toward packet-based telecommunication equipment.
- Further leveraging of telecommunication to optimize transmission system usage.
- DER growth.
- Distribution system applications that benefit the overall electric system.
- Utilization of the utility telecommunication network by market participants to provide required data to the AESO.
- Lower-cost telecommunication solutions.

The utility telecommunication network is planned in coordination with the AESO and TFOs. A telecommunication work group is in place with the major TFOs (AltaLink, ATCO, ENMAX and EPCOR) and DFO (Fortis Alberta) in the province. As the operators and primary planners of their utility telecommunication networks, the work group supports the AESO in the creation of the wider *2020 Telecommunication Long-term Plan* (2020 Telecommunication LTP). The AESO's role in telecommunication planning at the provincial level is to lead coordinated planning between the utilities, provide long-term direction and identify inter-organizational opportunities.

In developing the 2020 Telecommunication LTP, which is primarily an update to the *2017 Telecommunication Long-term Plan*, the AESO evaluated the current and future needs and drivers for the utility telecommunication network. The 2020 Telecommunication LTP aligns with long-term transmission planning, which is a major driver of new telecommunication development and opportunities.

In planning the utility telecommunication network, critical and core services remain the primary need drivers. Other services can be considered based on their benefit to the system.

The following are considered to be the critical and core telecommunication services:

- Teleprotection.
- Supervisory control and data acquisition.
- Inter-control centre communication protocol.
- Voice communications.
- Mobile land radio communications.

Projects in the 2020 Telecommunication LTP have been selected to significantly reduce both planned and unplanned outages on the telecommunication network, and therefore improve the overall reliability and availability of the transmission system. Particular focus is placed on improvements to the 500 kV and 240 kV transmission systems. As standard process, individual business cases and justification documents are still required to support execution and determine the required timing of proposed telecommunication projects.

The 2020 Telecommunication LTP lists key projects for the near-term (five year) and medium-term (ten-year) time periods. When applicable, project alternatives are also outlined. The selected projects follow the outlined planning guidelines and, where possible, leverage existing telecommunication infrastructure.

The 2020 Telecommunication LTP outlines planning guidelines for the following:

- Secondary paths.
- Bandwidth capacity.
- Fibre deployment.
- Microwave radio deployment.

Other telecommunication initiatives are also specified that deal with voice and data communications between utility control and operation centres, DER communications, mobile radio system upgrades, and emergency restoration planning.

Of these other telecommunication initiatives, DER communication is the least defined, with several telecommunication options. The telecommunication requirements for DER are still to be determined, and their influence on the distribution and transmission systems is being evaluated.

The utility telecommunication network represents a key component of Alberta's transmission system. For the full details of the 2020 Telecommunication LTP, please refer to the document at *www.aeso.ca/grid/LTP.*

4.5 TRANSMISSION CAPABILITY ASSESSMENTS TO INTEGRATE ADDITIONAL GENERATION

South and Central East

The AESO published the 2018 Capability Assessment to elaborate on information provided in the 2017 LTP. This assessment included the transmission system's capability to integrate additional renewables generation subsequent to the announcement of the projects selected for the REP Round 1. The primary focus was on—but not exclusive to—generation integration capability in renewables-rich central east and southern Alberta.

In early 2019, the AESO published an *Addendum* to the 2018 Capability Assessment covering the impacts on system capability from the REP Rounds 2 and 3. The *2019 Transmission Capability Assessment for Renewables Integration* was subsequently published in April 2019, and includes the results from the Addendum, various sensitivity studies, and captures the impacts of proposed system projects.

Methodology

Integration capability information for the south and central east areas was updated as part of the planning studies for the 2020 LTP. The most recent assessment identifies the remaining capability in central east and southern Alberta, and provides an update on capability that will be added as a result of planned transmission.

In assessing existing and planned transmission system capability for the south and central east areas:

- Incremental generation was guided to the locations which lead to maximized utilization of the transmission system.
- Integration capability was evaluated so thermal constraints do not occur under system-normal conditions and are manageable under contingency conditions using Remedial Action Schemes (RAS) that could result in curtailing renewables generation.
- Capabilities indicated for these regions are applicable for both renewables and conventional generation. However, the transmission system capability to integrate conventional generation in these areas could be slightly lower than those estimated for renewables due to coincident higher generation dispatch levels of existing thermal assets.

Current transmission system capability

If the transmission system is optimized and RAS are employed, there is an upper limit of approximately 450 MW of remaining integration capability in the south and central east. Optimal distribution of this 450 MW of integration capability is approximately 300 MW in the southwest and 150 MW in the southeast. When the transmission system is optimized, capability in the central east area is 0 MW; however, a small quantity of generation can still be integrated into this area, recognizing that this could decrease overall system capability. To optimize use of the existing transmission system in renewables-rich areas of Alberta, the AESO assumes connection of new generation to 240 kV substations.

Based on the connection interest expressed to the AESO and the projects that formally applied under the REP, the south and central east areas continue to garner significant interest from the market for renewable energy development. These development interests are also in alignment with the availability of wind and solar resources in the province as shown in Figures 4.5-1 and 4.5-2.

View Assessments for Transmission Capability for Renewables Integration:
www.aeso.ca/grid/ltp/capability

Figure 4.5-1: Alberta's wind resource potential

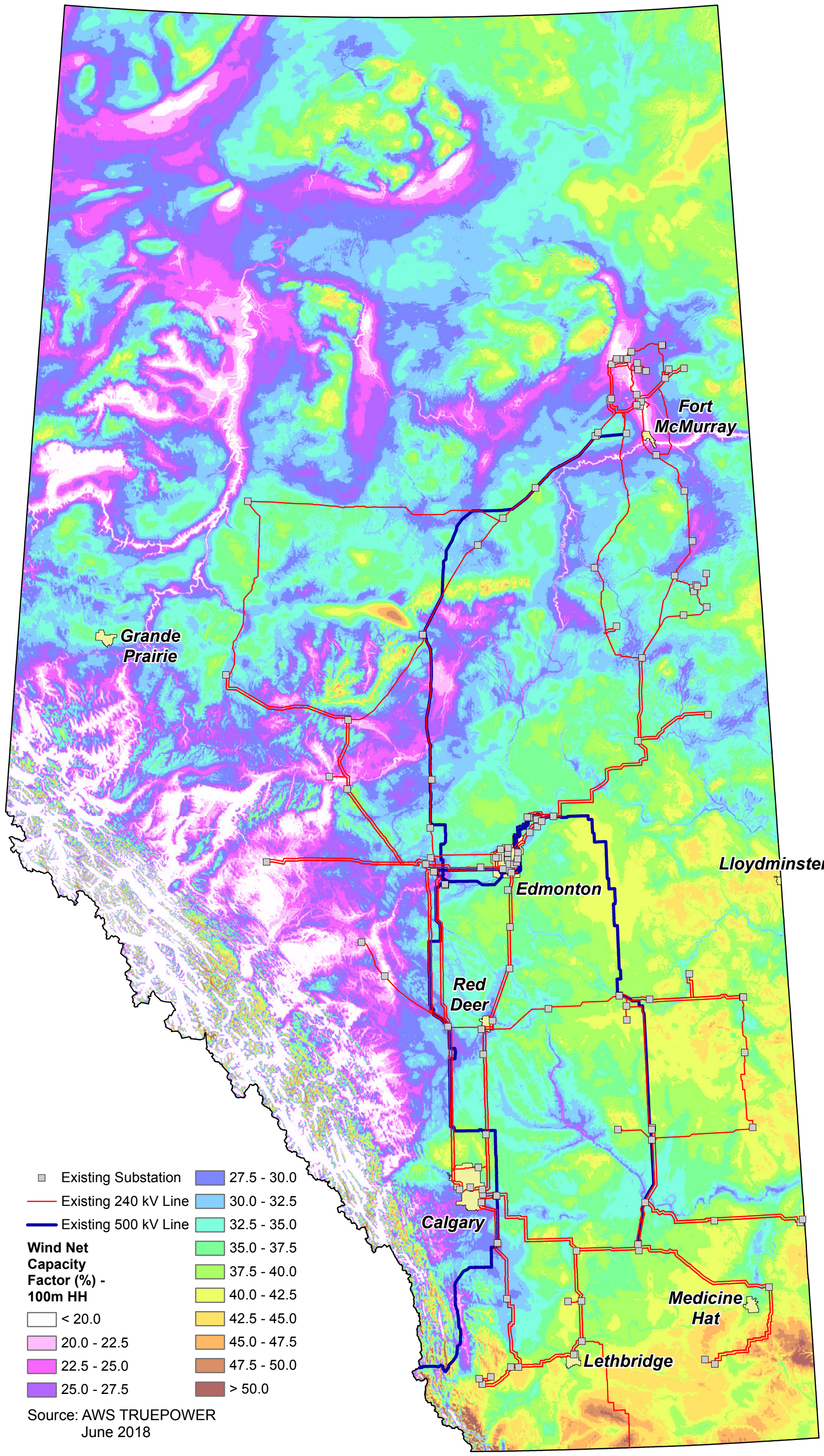
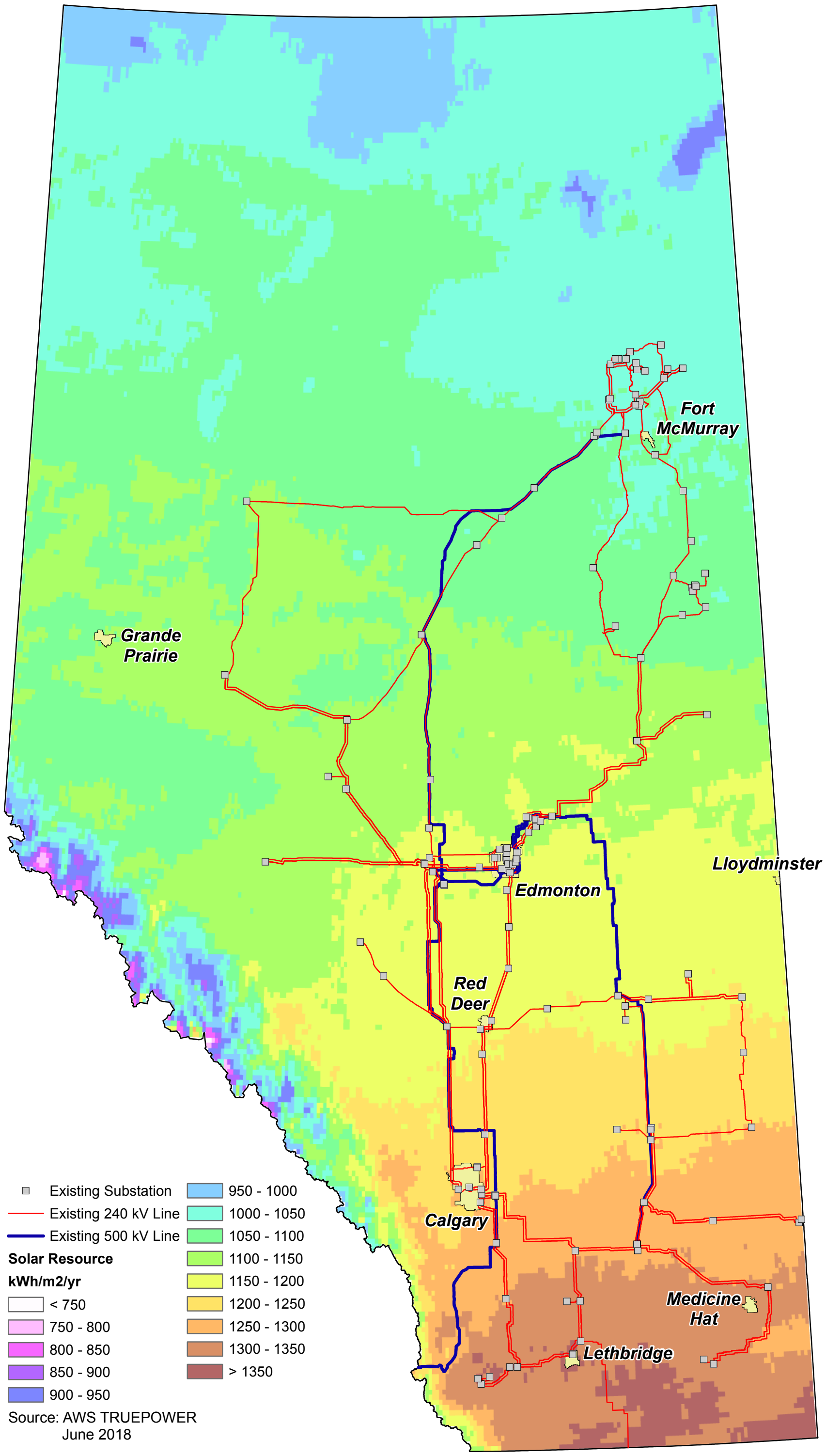


Figure 4.5-2: Alberta's solar resource potential



Capability enhancement plans

Two transmission developments previously identified by the AESO remain the most effective for integrating the maximum amount of renewables generation in southern and central east Alberta: CRPC and CETO.

These developments will enhance the electric system's capability to transfer power out of the areas where it is produced and deliver it to the load centres where it is needed. Both projects are being staged with construction milestones to introduce flexibility, enabling incremental transfer capability as renewable resources are developed.

The approved PENV project is also an important component of the renewables integration plan, providing generation collection capability and extending the 240 kV transmission system in the central east area to Vermilion and Edgerton. The project will add approximately 350 MW of overall system capability and is expected to be in service by 2022. The CRPC, CETO and PENV transmission developments are shown in Figure 4.5-3.

Chapel Rock-to-Pincher Creek Transmission Development

CRPC enables the use of the existing 240 kV system in the Pincher Creek and greater southwest areas, extending east to Lethbridge for collecting renewables generation.

This development will add approximately 600 MW of generation integration capability in the southwest. It will include one new 240 kV transmission circuit (approximately 40 km long) between the Pincher Creek area and a new 500 kV substation to be called Chapel Rock, and the addition of voltage support equipment at the existing Goose Lake substation. This 40 km transmission development will expand the collector system in the area and enhance the transfer-out capability by providing an additional 240 kV/500 kV path that will connect the Pincher Creek area to Calgary. This new development allows the system to better utilize the Lethbridge—Milo—Langdon, Windy Flats—Foothills and Chapel Rock—Bennett transmission paths connecting the southwest to the Calgary-area load centre. The AESO is planning to submit a NID Application to the AUC in 2020 and will propose a construction milestone based on future sufficiently certain generation developments in the area.

In addition to CRPC, a number of other transmission developments designed to enhance renewables integration capability were carefully evaluated: Foothills Area Transmission Development West (FATDW), Etzikom Coulee–Whitla line (ECW), the Picture Butte–Etzikom Coulee line (PBEC), and Goose Lake–Etzikom Coulee (GLEC).

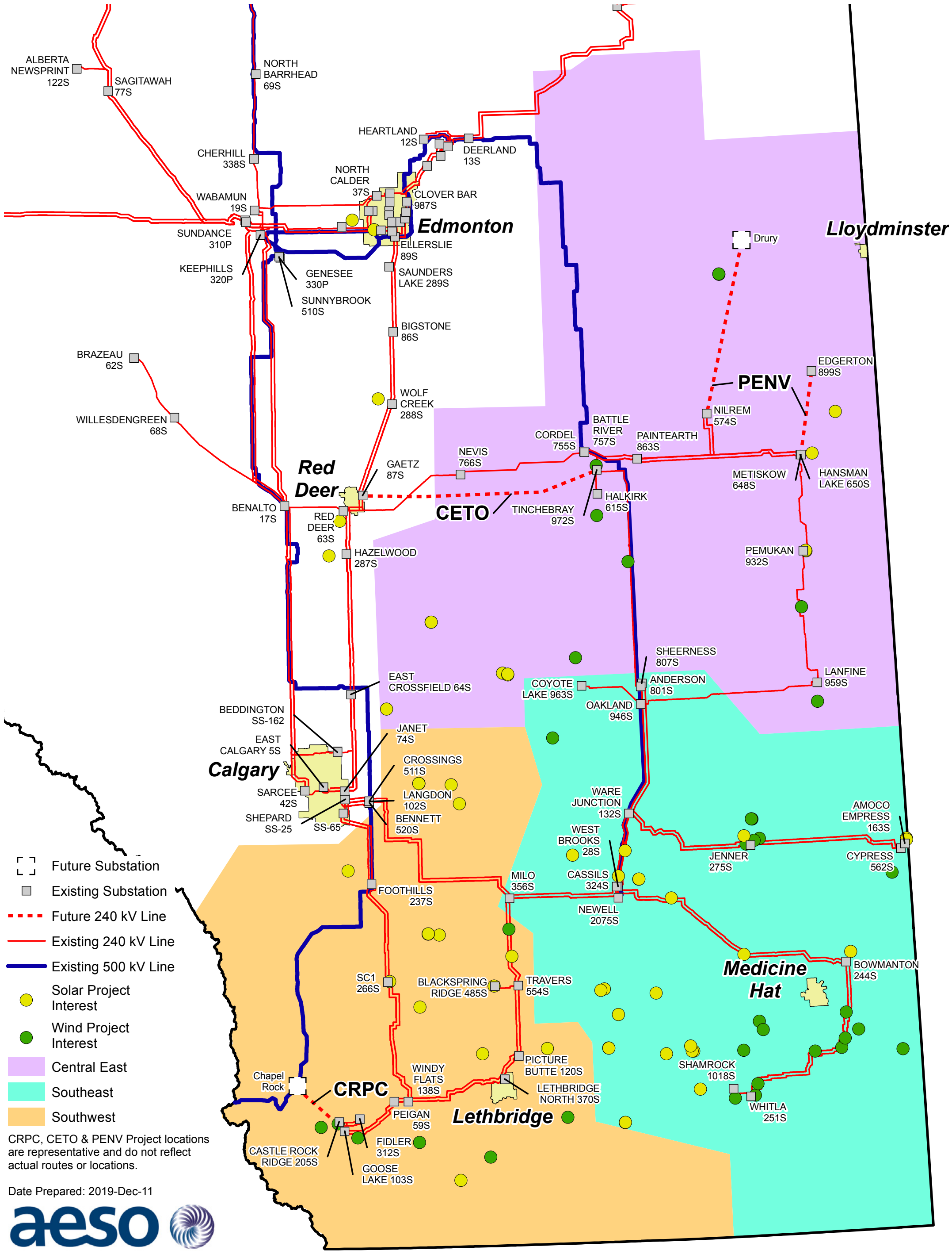
Among these projects, it was determined that CRPC allows the highest level of renewables generation integration in the southwest, effectively enhances transfer-out capability from the area, and also contributes to the restoration of the Alberta—B.C. intertie capability. Consistent with the AESO's goal of optimizing transmission system capability, the FATDW, ECW, PBEC and GLEC proposed development projects will be cancelled.

Central East Transfer-out Transmission Development

CETO will strengthen the existing regional transfer-out path and is the most efficient enhancement to integrate incremental renewable-resource generation in central east Alberta. The selected configuration of CETO is the addition of two 240 kV transmission circuits from the Tinchebray substation to the Gaetz substation.

The two circuits will add approximately 700 MW of integration capability. Combined with PENV, CETO will enable approximately 1,000 MW of new renewables generation capability, primarily in central east Alberta. The AESO plans to submit a NID Application to the AUC in 2020 and will propose construction milestones for the project.

Figure 4.5-3: Planned transmission projects supporting integration of renewables development (CRPC, CETO and PENV)



Northwest, Northeast and Edmonton

The AESO also performed integration capability studies for regions where significant conventional generation has traditionally developed.

In assessing existing and planned transmission system capability for the conventional generation-rich Northwest, Northeast, and Edmonton Planning Regions:

- Assessments were made such that thermal constraints do not occur under system-normal conditions and contingency conditions without using RAS.
- The capabilities indicated are applicable for both renewables and conventional generation, with the capability for integrating renewables being slightly different due to differences in generation pattern and merit order, as well as the use of RAS.
- The assessment is informed by developer interest and active projects in the AESO project list, and the results are intended to provide guidance to generation developers in the areas with existing and planned transmission system capability.

Methodology

In developing generation integration capabilities for the Northwest, Northeast, and Edmonton Planning Regions, the AESO considered only locations with strong transmission system backbone (transmission buses at 240 kV or above in study areas). Incremental generation is added to the transmission backbone to maximize utilization of the transmission system capability without leading to thermal and voltage violations under contingency conditions and assumes no reliance on RAS. Capability would increase further if generation-shedding RAS is considered. Existing generation is dispatched to its respective maximum capacity, with the assumption that retirement of the existing generation can be replaced with other generation at a 1-1 ratio in capacity. Therefore, this capability study reflects the amount of generation that can be accommodated in these locations in addition to what is currently connected.

The three regions with higher potential for conventional generation developments have different system characteristics resulting in different presentations of capability information:

- **Northwest Planning Region**–the region is complex with three 240 kV transmission lines connecting to the Wabamun Lake area and many 138/144 kV local transmission networks. Transmission capabilities are provided at individual 240 kV buses without a regional total because system capability for the Northwest needs to consider both outflow constraints limited by the main 240 kV system and local constraints driven by the 138/144 kV networks.
- **Northeast Planning Region**–the focus of the assessment is primarily the system outflow capability of the 240 kV loop in the Fort McMurray area. The area is outflow constrained by a single 500 kV line and three 240 kV transmission lines linking the Fort McMurray area with the rest of the system.
- **Edmonton Planning Region**–with its strong 500 kV and 240 kV transmission network, the capability is primarily driven by the total outflow from the three existing sites: Sundance, Keephills and Genesee.

Current transmission system capability

Table 4.5-1 below summarizes the current approximate integration capabilities for the Northwest, Northeast and Edmonton Planning Regions. These capabilities indicate the amount of additional generation that can be integrated in addition to the facilities that already exist today. If existing generators retire, it is assumed new generators with the same capacity can develop in their place.

Table 4.5-1: Northwest, Northeast and Edmonton existing integration capability

Planning Region	Existing Capability (MW)
Northwest	**N/A**
Wesley Creek	250
Little Smoky	300
Louise Creek	1,000
Mitsue	550
Sagitawah	1,000
Bickerdike	100
Northeast (Fort McMurray)	**500**
Edmonton	**2,400**
Sundance	650
Keephills	500
Genesee	1,250

Capability enhancement plans

As identified in the near-term studies, the Fox Creek area has thermal constraints under peak load conditions when the Northwest is importing power from the rest of the system. This thermal constraint results in very limited capability at Bickerdike. However, with the Fox Creek area transmission reinforcement identified in the near-term transmission plan for the Northwest, the Bickerdike substation can accommodate additional generation. Operational measures such as re-configuring the transmission system after a contingency could potentially be utilized to further increase system capability to accommodate additional generation. The AESO continues to monitor developments in the area and will propose the appropriate transmission reinforcements as required.

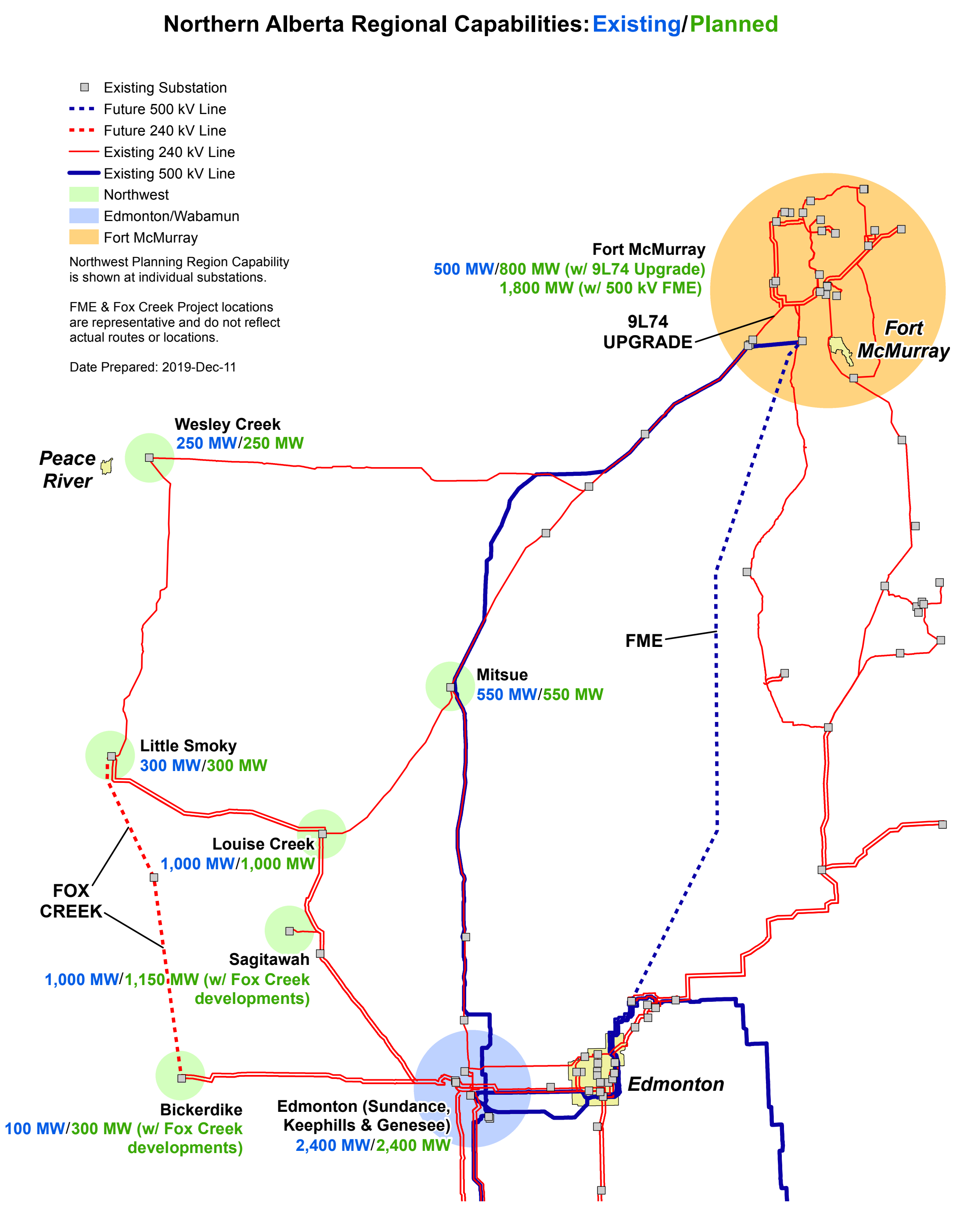
For the Northeast, the thermal rating of the 240 kV line 9L74 between the Birchwood Creek and Dover substations is the limiting constraint for the 12L41 (500 kV FMW line) contingency. If the thermal rating of 9L74 is upgraded, the integration capability for the Northeast can increase from 500 MW to 800 MW. If generation development is expected to be above 800 MW, the approved 500 kV FME line will need to be developed, increasing the generation integration capability from 500 MW to 1,800 MW.

Table 4.5-2 below and Figure 4.5-4 on the following page summarize the planned increase in generation integration capabilities when compared to the existing capabilities. Planned capabilities shown are inclusive of the existing capabilities, and reflect the total capability after transmission developments are in place. The table also shows the existing and planned transmission capabilities for different regions of the system.

Table 4.5-2: Total generation integration capability considering planned transmission developments

Planning Region	Existing Capability (MW)	Planned Capability (MW)	
Northwest	**N/A**	**N/A**	
Wesley Creek	250	250	
Little Smoky	300	300	
Louise Creek	1,000	1,000	
Mitsue	550	550	
Sagitawah	1,000	1,150 (with Fox Creek developments)	
Bickerdike	100	300 (with Fox Creek developments)	
Northeast (Fort McMurray)	**500**	**800 (with 9L74 upgrade)**	**1,800 (with 500 kV FME)**
Edmonton	**2,400**	**2,400**	
Sundance	650	650	
Keephills	500	500	
Genesee	1,250	1,250	

Figure 4.5-4: Integration capabilities for the Northwest, Northeast and Edmonton Planning Regions



4.6 DISTRIBUTED ENERGY RESOURCES

DER are typically smaller in scale than centralized and conventional power generation facilities and are directly connected to the distribution system. To date, there are approximately 500 MW of DER in Alberta. At this current volume, the AESO is confident that existing requirements and practices allow for reliable management of the transmission system. In the future, however, there is potential for higher DER levels to develop, which may influence the planning and operation of the transmission system and require additional visibility and control.

Following are considerations:

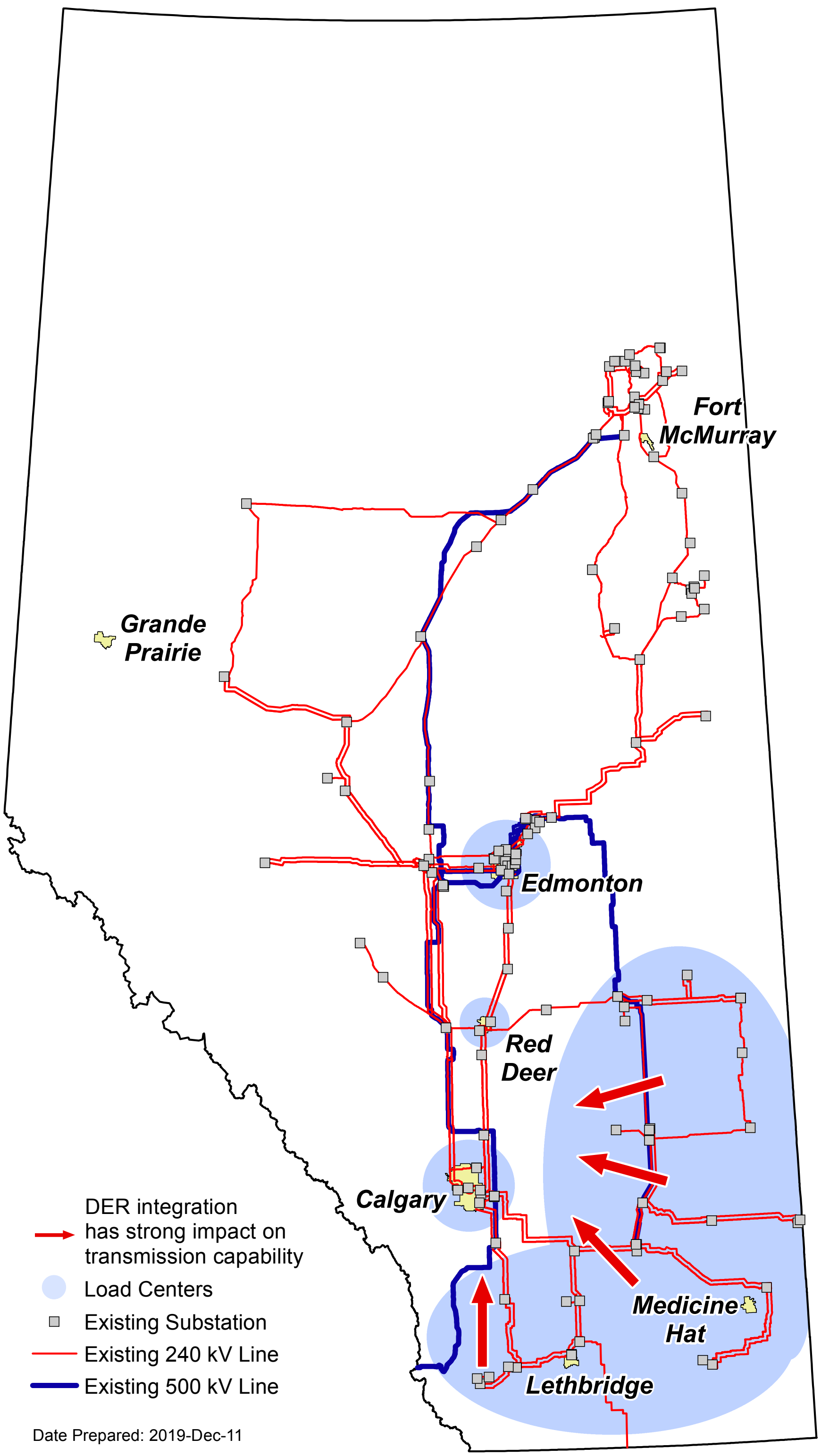
- If DER locates near load and is able to reliably follow the local load pattern, it can potentially reduce loading on the transmission system. However, in areas where transmission is constrained by generation outflow, adding more DER exacerbates transmission constraints and can cause congestion.
- Load levels in the southern and central east areas are relatively low compared to in-merit generation, and it is generation surplus that drives congestion. More DER in these areas will add to the constraint, since existing generation is already serving local load. DER could also change the flow pattern on local transmission systems or further exacerbate loading, depending on local constraints (Figure 4.6-1).
- DER in the form of rooftop solar could reach higher levels in more densely populated urban areas.

An assessment was undertaken on the impacts of DER integration on transmission system capability at key urban areas within Alberta. The assessment assumes up to approximately 300 MW of PV solar energy in major cities; this is based on the assumption that approximately 20 to 25 per cent of homes would install rooftop PV modules.

Key findings are as follows:

- There is a reduction of approximately 60 MW in transmission system capability in the south and central east for every 100 MW of DER integrated in the City of Calgary (up to 300 MW of DER generation was assessed).
- Integration of 100 MW of DER in the cities in the south and central east areas will use 100 MW of transmission system capability for renewables integration in these regions (up to 200 MW of DER generation was assessed).
- DER integration in the cities of Edmonton and Red Deer will not impact transmission system capability to integrate renewables generation in the south and central east areas (up to 300 MW and 70 MW of DER generation was assessed in the City of Edmonton and the City of Red Deer respectively).
  - The cites of Edmonton and Red Deer are near strong transmission hubs in the AIES and integration of additional generation on the distribution system in these areas will have minimal impact on existing transmission system capability.
- The location and size of future generation is an important factor to consider when integrating generation on the distribution system, as it may produce local system constraints.
- More transmission system capability is planned for the south and central east areas and it will allow more DER to develop in these areas along with transmission-connected generation.

Figure 4.6-1: DER integration impact



4.7 ENERGY STORAGE

Over the past few years, utility-scale energy storage technology has become an important consideration in the planning and operation of the power system, as energy storage can take on multiple attributes:

- Generation-like when discharging onto the grid to supply stored energy.
- Load-like when charging from the grid to store energy to discharge at a later time back onto the grid.
- Transmission-like or distribution-like when connected to the transmission/distribution system to reduce peak demand, congestion, and defer capital build.
- Customer-like when on the customer's side of the meter, managing customer bill costs.

Overall, energy storage can offer important value and benefits:

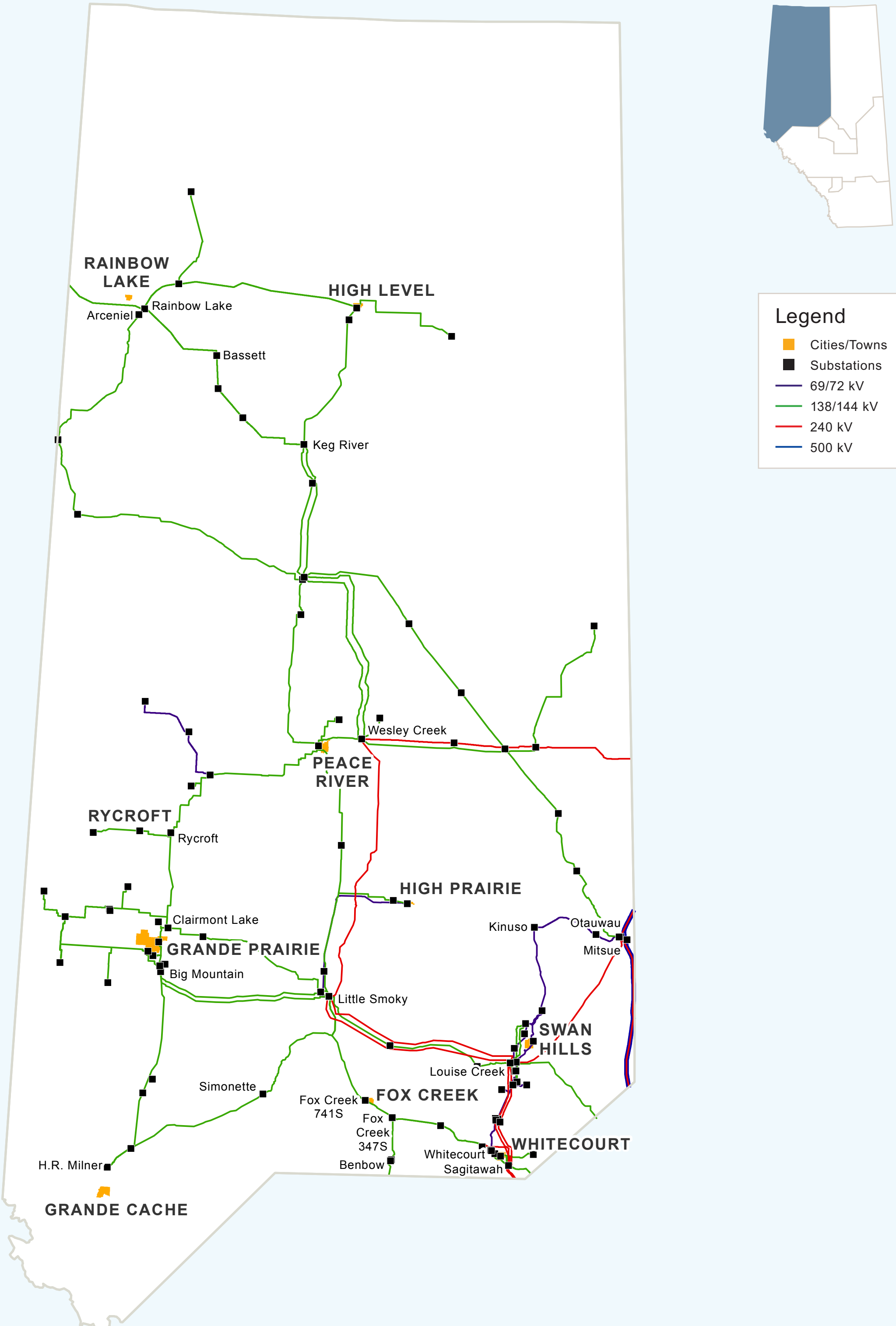
- It has the potential to optimize intermittent generation, thereby helping to strengthen reliability.
- It can reduce costs to transmission system infrastructure through transmission and distribution deferral, resulting in potential cost benefits to customers.
- Fast frequency response from energy storage can enable reductions in required volumes of certain ancillary services, also resulting in potential cost benefits to customers.

The *AESO Energy Storage Roadmap,* published in August 2019, sets out the AESO's plan to facilitate the integration of energy storage technologies into AESO Authoritative Documents and grid & market systems. The objective of the roadmap is to enable energy storage in Alberta following guiding principles that include treating energy storage as its own unique asset class and removing barriers to its integration.

> The AESO will continue to refine the Energy Storage Roadmap, review and consider active connections projects wanting to connect in 2020, and prepare for long-term implementation of roadmap recommendations.

NORTHWEST PLANNING REGION

Existing transmission system



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4.8 NEAR-TERM REGIONAL TRANSMISSION PLANS

Northwest Planning Region

Overview and forecast

From a geographic perspective, the Northwest Planning Region represents approximately one-third of the province, with five per cent of the population. The largest centre is the City of Grande Prairie, with a population of less than 100,000. Residential and commercial electricity demand is relatively low compared to northwest industrial demand, especially when compared to residential and commercial demand in other regions. There is also some agricultural activity in the region.

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

The Northwest Planning Region currently contains 988 MW of generation capacity, primarily gas-fired. There has been an increase in gas-fired and biomass generation capacity over the past 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).

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

Table 4.8-1: Northwest regional reference case load and generation forecast

Calendar Year	2018 (MW)	2024 (MW)
Region Peak Load	1,223	1,254
Coal-fired / Coal-to-gas	144	0
Cogeneration	147	162
Combined-cycle	73	73
Simple-cycle	442	535
Hydroelectric	0	0
Wind	0	0
Solar*	0	0
Other	182	182
Total Generation Capacity	988	952

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

Existing transmission system

The Northwest Planning Region is primarily served by a 240 kV network that moves power into the region from generation in the Wabamun Lake area, and from cogeneration in the Northeast Planning Region. Local load is supplied via 144 kV networks from the Louise Creek, Little Smoky, Wesley Creek, Sagitawah, Bickerdike, Mitsue, and North Barrhead 240 kV substations. A portion of the load in the Swan Hills, High Prairie and Peace River areas is served by 69/72 kV networks.

Transmission project status

- **Rycroft project NID Application for reactive power support**–filed with the AUC in December 2017 and approved in May 2019. The targeted in-service date for this project is 2021.

Transmission plans

Several 138/144 kV transmission lines in the Whitecourt to Fox Creek area can overload under system normal or outage conditions, depending on system dispatch conditions. In addition, transformers at the Little Smoky substation can also overload if the companion transformer is out of service. Thermal overload and low voltage conditions are observed in the Grande Prairie and Grande Cache areas under outage conditions as well. Overload is also observed in the Rainbow Lake area and there are under voltage conditions in the High Prairie area.

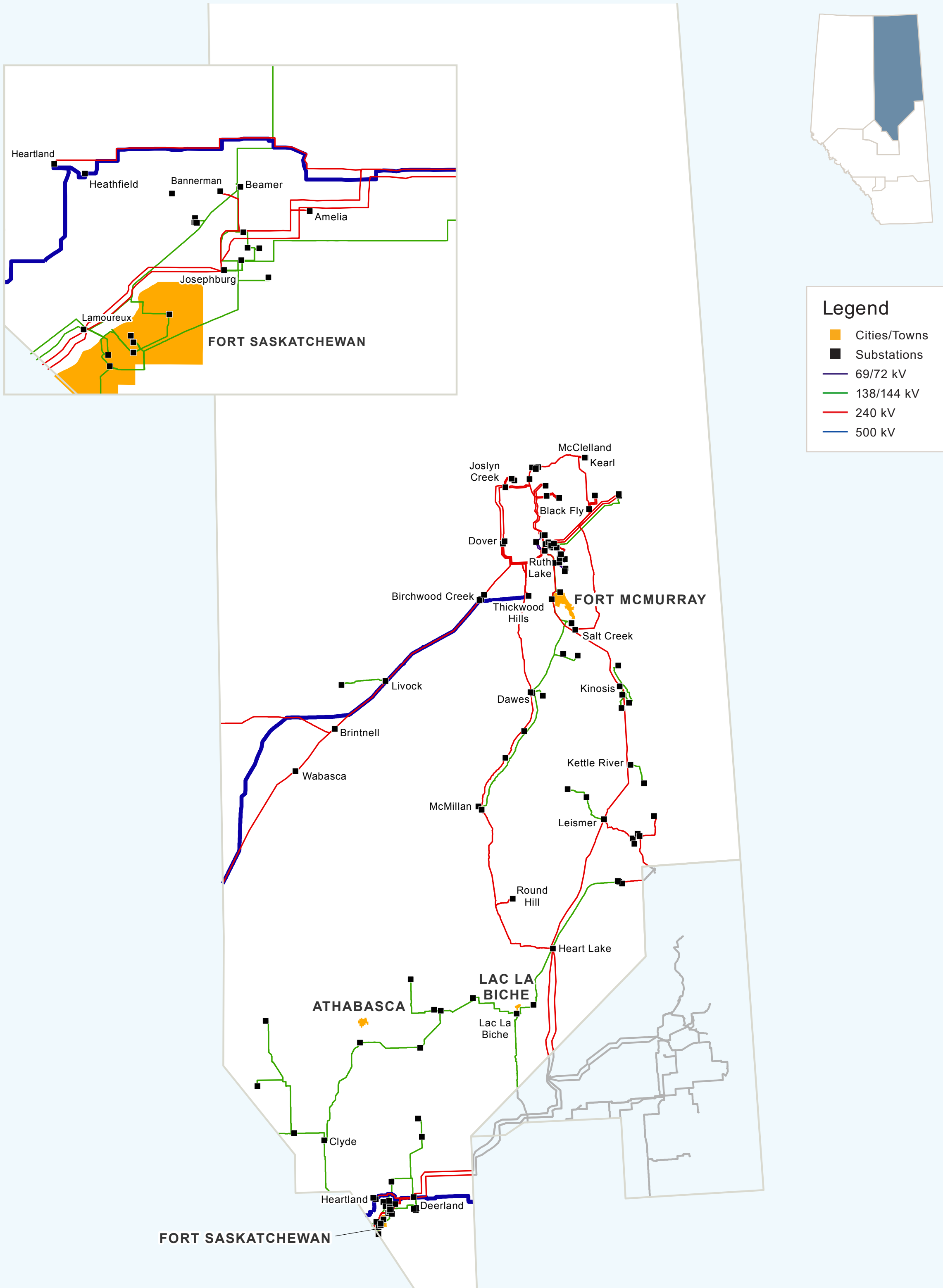
There are a number of generation proposals in the Northwest Planning Region. While not specified in the forecast provided, the AESO has assessed them in various sensitivity considerations. System performance in the area will be improved with the addition of some generation, but too much could trigger additional transmission system reinforcements.

Table 4.8-2: Developments required to mitigate the identified constraints

Development	Description	Driver
Fox Creek Reinforcement	Build a 240/144 kV substation near Fox Creek Build a new single-circuit 240 kV line from Little Smoky 813S to new Fox Creek to Bickerdike 39S Increase line rating for 7L199 from Fox Creek 741S to Fox Creek 347S Increase line rating for 720L from Fox Creek 347S to Benbow 397S	Load - thermal
Grande Prairie Area	Build a new 240/144 kV substation on 9L11 Build a new single-circuit 240 kV line from the new substation to Clairmont Lake 811S, initially operated at 144 kV	Load - thermal
Grande Cache Area	Voltage support device at H.R. Milner 740S and/or Simonette 733S	Load - voltage
Little Smoky substation – increase transformation capacity	Replace existing 240/144 kV transformers with higher-capacity units (or add a third unit) at Little Smoky 813S	Load - thermal
Rainbow Lake	Increase line rating for 7L64 from Bassett 747S to Arceniel 930S	Load - thermal
High Prairie Area	Voltage support device at Kinuso 727S or new transformer at Otauwau 729S	Load - voltage

NORTHEAST PLANNING REGION

Existing transmission system



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Northeast Planning Region

Overview and forecast

The Northeast Planning Region is sparsely populated, accounting for approximately three per cent of the provincial population with commensurately small residential and commercial load. 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 oil sands industry and is directly linked to future oil sands projects.

Despite the low population, the Northeast Planning Region contains about 28 per cent of Alberta load. 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 as oil sands 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. Due to the ramp up of oil sands and other industrial projects, this is Alberta's fastest-growing planning region in terms of load, with almost 1,171 MW of new load expected by 2039.

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 past 10 years, the Northeast Planning Region has seen the largest amount of generation capacity growth compared to any other planning region. Most generation development in the region has come from industrial activity and cogeneration related to the oil sands industry.

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 4.8-3: Northeast regional reference case load and generation forecast

Calendar Year	2018 (MW)	2024 (MW)
Region Peak Load	3,309	3,582
Coal-fired / Coal-to-gas	0	0
Cogeneration	3,489	3,760
Combined-cycle	0	0
Simple-cycle	0	0
Hydroelectric	0	0
Wind	0	0
Solar*	0	0
Other	149	149
Total Generation Capacity	3,638	3,909

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

Existing transmission system

The Northeast Planning Region transmission system consists of a 240 kV network primarily serving large industrial operations in the Fort McMurray and Fort Saskatchewan areas. In addition, local 138/144 kV networks serve load across the planning region. Several 144 kV networks connect load and BTF facilities in the Fort McMurray area.

Transmission project status

- **FMW 500 kV Transmission Project**–a new 500 kV alternating current (AC) transmission line between the Sunnybrook substation in the Wabamun Lake area and the new Thickwood Hills substation southwest of Fort McMurray. In the spring of 2019 the project was energized and is now in service.
- **Beamer–Shell 138 kV line Rebuild**–approved by the AUC with both load-based and generation-based construction milestones. The milestones have not been reached at this time.

Transmission plans

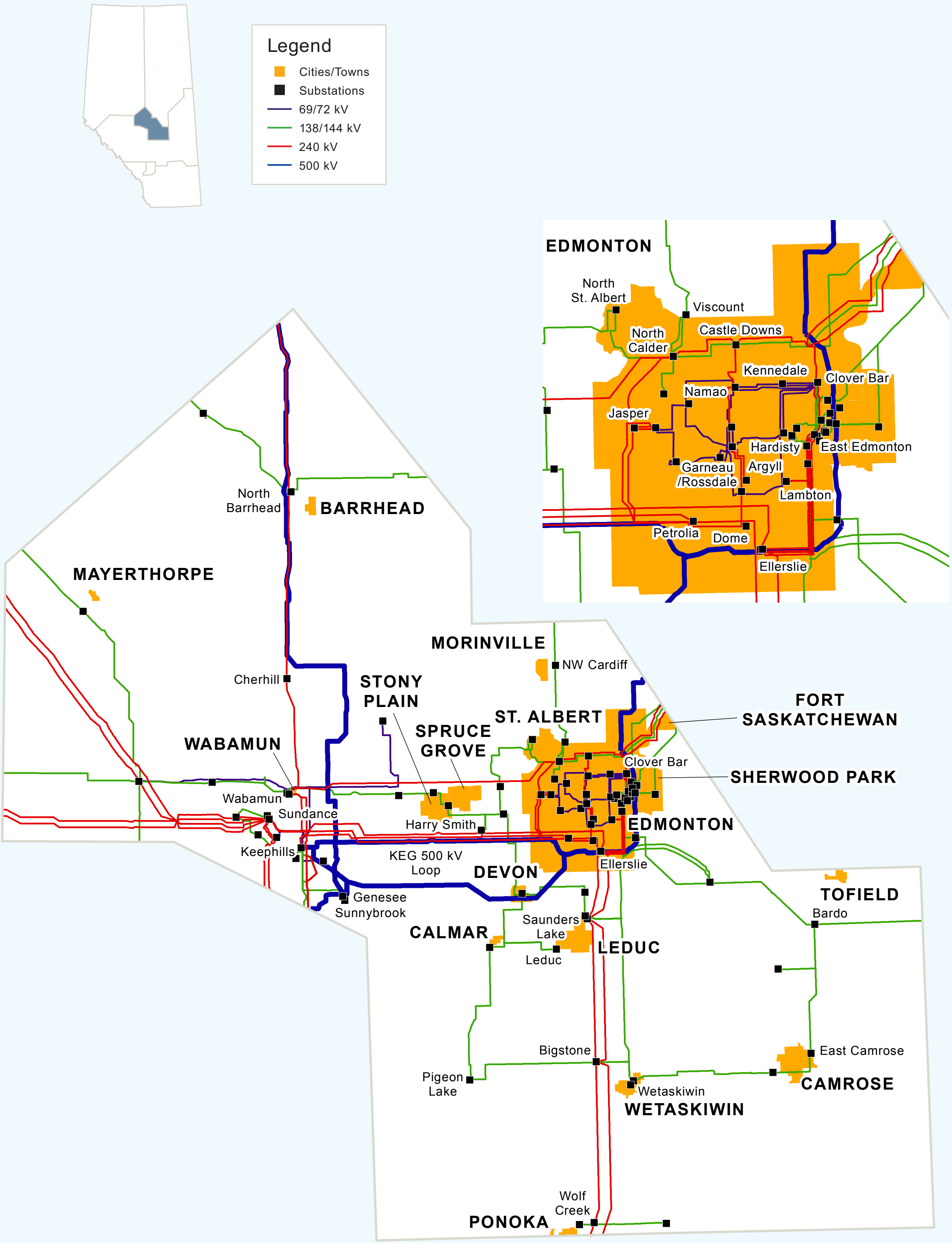
Voltage criteria violation is observed at the Kearl substation under high load conditions. To mitigate this violation, a new voltage support device is required at the McClelland substation. There is no other observed thermal and voltage criteria violation in the near term.

Table 4.8-4: New voltage support device required to mitigate voltage criteria violation

Development	Description	Driver
NE of Fort McMurray	New voltage support device at McClelland 957S	Load - voltage

EDMONTON PLANNING REGION

Existing transmission system



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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 accounts for the most significant amount of provincial generation capacity, specifically in the Wabamun Lake area.

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 region consists of residential, commercial, oil refining, manufacturing and pipelines. 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 developments. 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.

The Edmonton Planning Region contains approximately 4,400 MW of generation capacity, with coal-fired generation contributing approximately 4,100 MW, and gas-fired generation contributing to the balance of the mix. The region has remained constant in terms of net generation capacity over the past 10 years. The 463 MW Keephills Unit 3 came in service in 2011, while the retirements of Sundance Units 1 and 2 have offset that capacity. Additionally, many of the coal-fired units have upgraded their facilities to gain incremental capacity.

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

Table 4.8-5: Edmonton regional reference case load and generation capacity forecast

Calendar Year	2018 (MW)	2024 (MW)
Region Peak Load	2,140	2,326
Coal-fired / Coal-to-gas	4,100	4,100
Cogeneration	49	49
Combined-cycle	0	0
Simple-cycle	250	250
Hydroelectric	0	0
Wind	0	0
Solar*	0	0
Other	0	0
Total Generation Capacity	4,399	4,399

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

Existing transmission system

The Edmonton Planning Region contains a large concentration of generation sources. It is the central transmission hub for the provincial network, connecting the north and south with transmission lines operating at 500 kV and 240 kV. These bulk transmission lines transfer power from this region to the rest of the province.

Local load in this region is served by a transmission network consisting of 500 kV, 240 kV, 138 kV and 69/72 kV lines. A 500 kV loop between the Wabamun Lake area and Edmonton feeds power from coal-fired generating plants in the Wabamun Lake area to the southeast corner of the City of Edmonton. The loop also extends to the Heartland substation in the Northeast Planning Region. A 72 kV system in Edmonton is dedicated to serving load within the city. The 138 kV system feeds load in the areas outside of the City of Edmonton as well as the heavy industrial area to the east.

Transmission project status

- **FMW 500 kV Transmission Project**–this project is connected to the Wabamun Lake area. Please see the Northeast Planning Region section for more details.

Transmission plans

There are several areas in and around Edmonton where overloads are observed. This includes the 72 kV system in the City of Edmonton, the 138 kV system north of the city towards the Town of Morinville, and the 138 kV system near the City of Leduc. There are also overloads on some 240 kV transmission lines and 500/240 kV transformers.

Table 4.8-6: Developments required to mitigate the identified constraints

Development	Description	Driver
North Calder to NW Cardiff	Increase line rating for 898L from North Calder 37S to Viscount 92S Increase line rating for 792L from Viscount 92S to NW Cardiff 191S	Load - thermal
The City of Edmonton	Build a new 240/72 kV transformer at Castle Downs substation and a new 240/72 kV Blatchford substation near Namao Build a new 72 kV circuit from Castle Downs substation to Kennedale substation, a new 72 kV circuit from Namao substation to Kennedale substation and a new 72 kV circuit from the new Blatchford substation to Namao substation Discontinue use of 72CK12 and 72CK13 from Clover Bar substation to Kennedale substation Upgrade 72 kV circuits between Clover Bar–Hardisty substations and Garneau–Rossdale substations	Load – thermal
South Edmonton	New 500/240 kV transformer for the Keephills–Ellerslie–Genesee (KEG) Loop	Generation - thermal
Leduc Area	Increase line rating for 805L from Bigstone 86S to Pigeon Lake 964S New voltage support device at Leduc 325S	Load – thermal and voltage

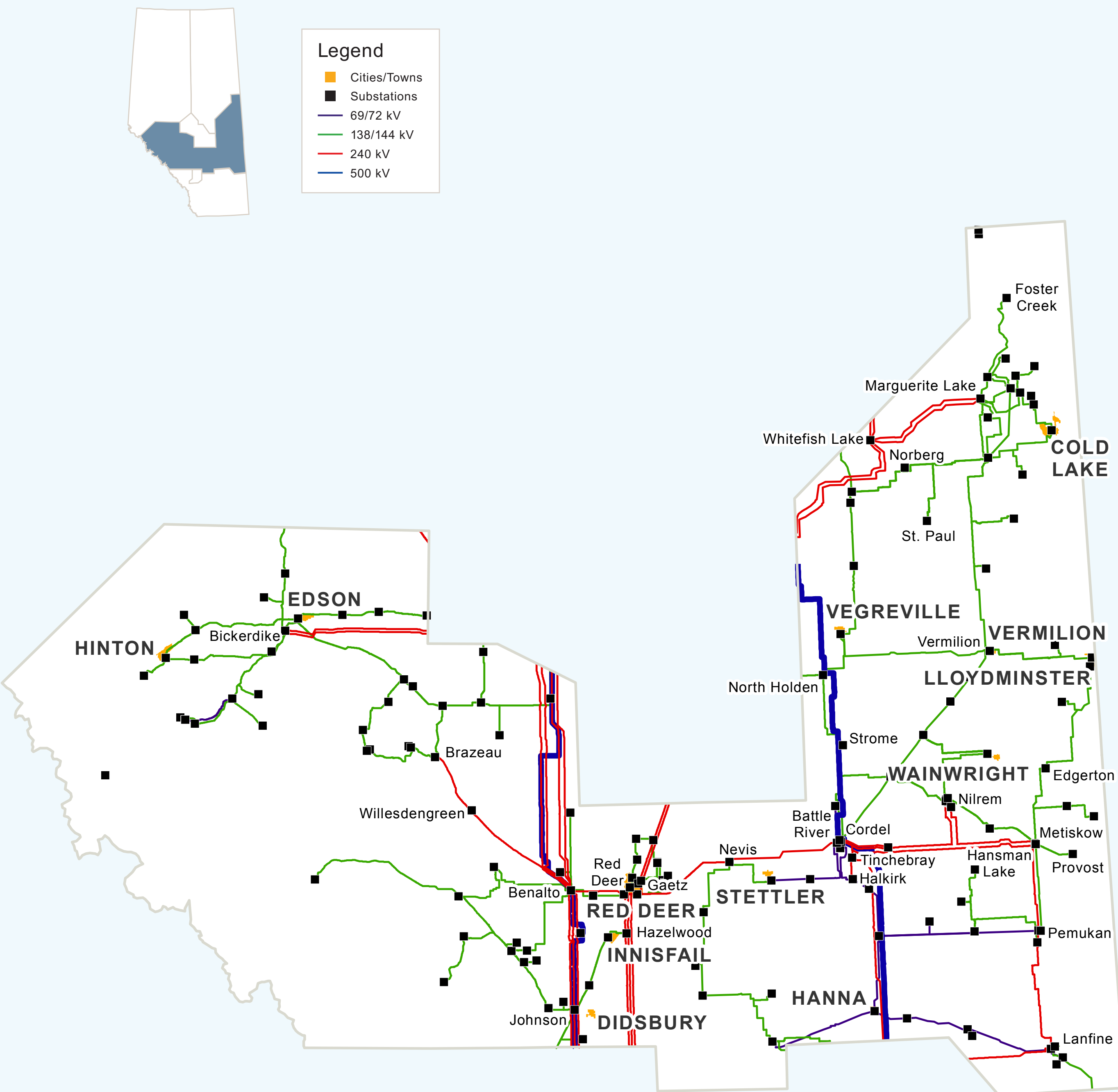
The 240 kV system and 500/240 kV transformer overloads in south Edmonton are observed under certain system conditions. For example, lower generation from the 240 kV connected units located in the Wabamun Lake area, coupled with renewables generation in the south flowing into the Edmonton region via the 500 kV HVDC lines, results in more power being injected onto the 500 kV system, particularly at the Ellerslie substation. A number of existing operational measures are effective in alleviating the observed overloads on 240 kV transmission lines. However, an additional transformer is required to help alleviate overloads on the 500/240 kV transformers.

The AESO is currently working with EPCOR Distribution and Transmission Inc. to determine the preferred solution to provide reliable long-term supply for the City of Edmonton. The primarily 72 kV looped normally open transmission network has a number of aging oil-filled cables, and is becoming constrained due to growing load within the Edmonton region. A long-term solution is required to provide reliable supply commensurate with an urban centre the size of the City of Edmonton.

Under peak load conditions, thermal overloads on the 138 kV path between East Edmonton and Fort Saskatchewan can be observed. The AESO is currently investigating a number of potential reinforcements to support this area. One of the options under consideration is the use of a storage system to support the area in the short and medium term, and defer transmission developments into the future.

CENTRAL PLANNING REGION

Existing transmission system



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Central Planning Region

Overview and forecast

The Central Planning Region spans the province east–west between the borders of B.C. 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. This area contains notable amounts of manufacturing, and there is significant oil sands development to the east in the Cold Lake area. The Central Planning Region also features a considerable amount of pipelines, particularly in the eastern portion of the region.

The 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 oil sands growth, and urban growth in the Red Deer area.

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. Net generation additions of 592 MW are primarily from wind and cogeneration.

The forecast for the Central Planning Region anticipates growth in gas-fired and renewables 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 4.8-7: Central regional reference case load and generation capacity forecast

Calendar Year	2018 (MW)	2024 (MW)
Region Peak Load	2,277	2,398
Coal-fired / Coal-to-gas	689	540
Cogeneration	1,145	1,241
Combined-cycle	0	0
Simple-cycle	5	51
Hydroelectric	485	485
Wind	261	509
Solar*	0	0
Other	50	50
Total Generation Capacity	2,635	2,876

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

Existing transmission system

There are six north-south 240 kV transmission lines that terminate in several substations within the Central Planning Region. These 240 kV lines connect the Edmonton and Calgary Planning Regions, and provide a strong source of supply from the bulk transmission system to areas within the Central Planning Region. The 240 kV system also extends to the western and eastern portions of the planning region, acting as sources to supply local area load, and also functioning as transfer-out paths for generation integration. In addition, both 500 kV HVDC lines run north-south through the region.

Local area load is supplied by looped 138 kV and 144 kV systems. The transmission system includes 72 kV lines and substations serving load in the eastern part of the Central Planning Region. The Hanna area is served by a 240 kV system, which also provides transmission access for renewables generation.

The Cold Lake area is served by a 240 kV double-circuit line and local 144 kV network to support oil sands and industrial operations. The western part of this planning region is primarily supplied by 138 kV lines serving load. The Brazeau hydroelectric plant is also located in this region.

Transmission project status

- **PENV**–the NID Application for this project was approved by the AUC in Q2 2019. The first stage, which is a 138 kV configuration, is expected to be in service by 2022.

Transmission plans

PENV will help to reinforce the area by providing more access for renewables development in the central east area and will help mitigate local load-driven overloads that were observed in previous LTPs. CETO will also be needed in order to provide an additional 700 MW of integration capability for renewables development in the region. The CETO transmission development will be triggered via a milestone associated with sufficiently committed generation developments.

There are currently three temporary RAS that mitigate voltage violations by tripping load after the first contingency at the Strome, Foster Creek and Norberg substations. To remove these RAS, additional voltage support devices will be required at the Strome, Foster Creek and St. Paul substations.

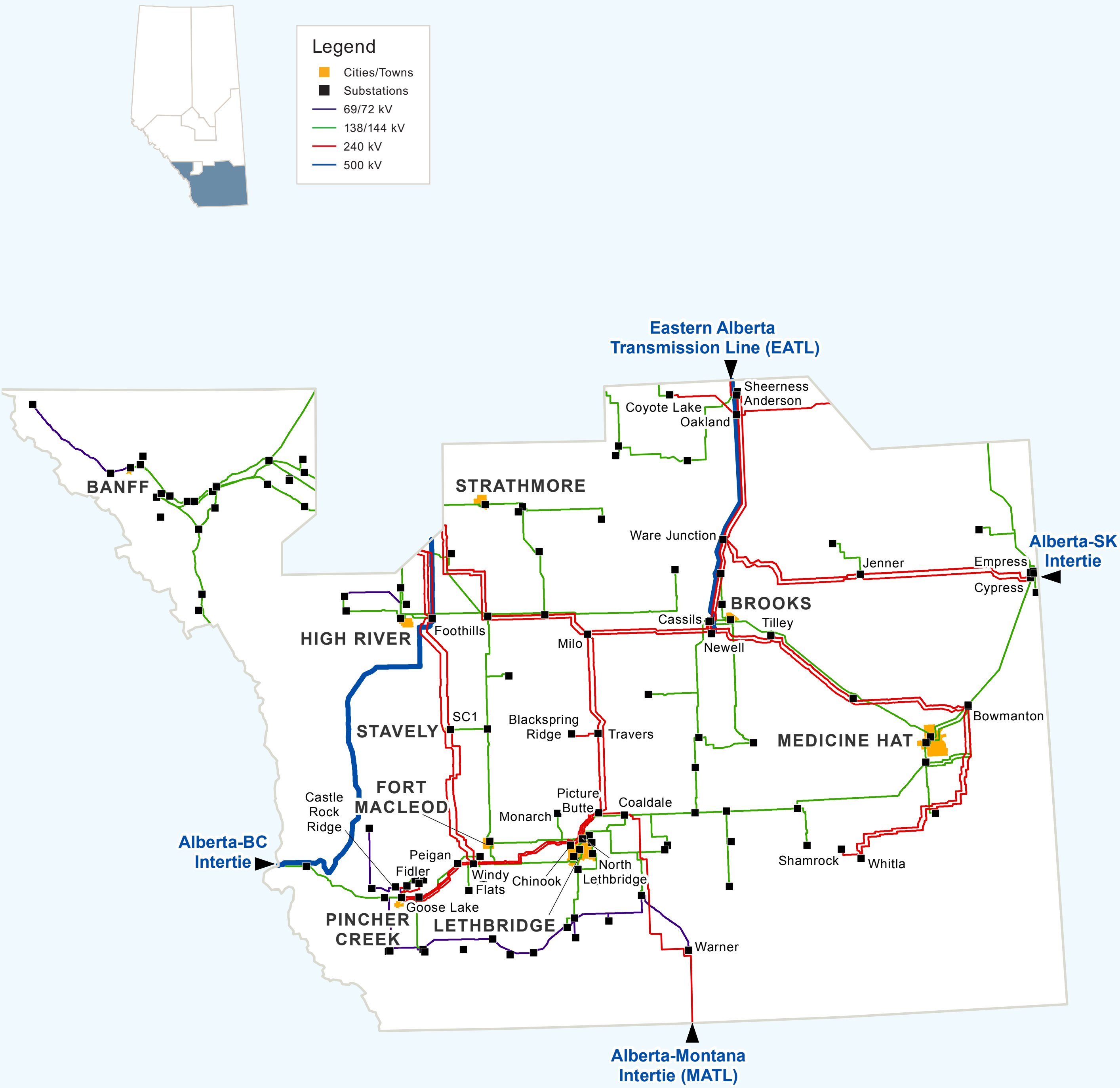
The Hanna Region Transmission Development was originally approved in two phases. Phase 1 has been completed and Phase 2, which covers 240 kV and 144 kV transmission lines, transformers, and capacitor banks in the Hanna area, is on hold. The AESO is reassessing the need for Phase 2 and a decision will be made in 2021 on the next steps.

Table 4.8-8: Developments required to mitigate the identified constraints

Development	Description	Driver
CETO	Two new 240 kV circuits from Tinchebray to Gaetz substations	Generation – thermal
Voltage Support	New voltage support devices at Strome, Foster Creek and St. Paul	Load - voltage

SOUTH PLANNING REGION

Existing transmission system



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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.

The South Planning Region represents about 11 per cent of 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 in urban centres.

This region currently contains 2,974 MW of generation capacity. Wind generation comprises the largest portion at 1,184 MW followed by coal-fired at 790 MW. The South Planning Region, which also contains hydro, solar, and cogeneration, has shown substantial growth in generation development over the past 10 years with a net growth of 769 MW of capacity.

The generation forecast for the South Planning Region anticipates growth in both gas-fired and renewables generation 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; approximately 1,100 MW of new wind generation is expected to come online in the near term from REP projects.

Table 4.8-9: South regional reference case load and generation capacity forecast

Calendar Year	2018 (MW)	2024 (MW)
Region Peak Load	1,481	1,499
Coal-fired / Coal-to-gas	790	790
Cogeneration	95	95
Combined-cycle	375	375
Simple-cycle	64	110
Hydroelectric	409	409
Wind	1,184	2,395
Solar*	15	131
Other	42	42
Total Generation Capacity	2,974	4,347

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

Existing transmission system

Load in the South Planning Region is primarily served through an extensive 138 kV transmission network, supplied by a regional 240 kV network connecting the main load centres with regional generation sources. The region also contains a small number of 69 kV facilities, including ones located south of Lethbridge and within Banff National Park.

There are existing 240 kV lines extending from the Calgary area to Brooks and Lethbridge, and a 240 kV network delivering power from the Sheerness and Battle River coal-fired generation units south to the Brooks area. The region also includes parts of the approved SATR project, consisting of several 240 kV circuits designed to collect geographically dispersed renewables generation sources and move power onto the bulk transmission network. In 2015, the double-circuit 240 kV line from Windy Flats (near Fort Macleod) to Foothills and a double-circuit 240 kV line from Whitla to Medicine Hat and on to Brooks were energized, enabling additional wind development opportunities in the south. EATL, a 500 kV HVDC line, terminates near Brooks and is capable of moving electric power from the north to supply load when generation in the south is low, and to the north when generation in the south is high.

Transmission project status

- **CRPC Transmission Development**–the AESO is preparing to file the NID Application in 2020. The construction timing for this project will depend on the pace at which renewables generation commits to connect to the transmission system in the southwest area of the province. The project has been reconfigured to include a single 240 kV transmission circuit connecting the new Chapel Rock substation to the Pincher Creek area.
- **Cancellations**–other components of the original SATR, which includes ECW, PBEC, and GLEC line developments, will be cancelled as CRPC enables the most effective renewables generation integration in the southwest.

Transmission plans

Table 4.8-10: Developments required to mitigate the identified constraints

Development	Description	Driver
Alberta–B.C. Intertie Restoration	Bennett substation transformer upgrade, clearance mitigations on 500 kV 1201L and reactive power support to help restore transfer capability of Alberta—B.C. intertie	Intertie
Chapel Rock–Pincher Creek Area Transmission Development	Add one new 240 kV transmission circuit approximately 40 km long between Pincher Creek area and a new 500 kV substation to be called Chapel Rock and voltage support equipment added at existing Goose Lake substation	Generation - thermal
West of Lethbridge Transmission Enhancement	Increase line rating for 172L between North Lethbridge 370S and Chinook 181S Increase line rating for 463L between Chinook 181S and Monarch Tap Add voltage support device at Monarch 492S	Load – thermal and voltage
Tilley Substation	Expand existing Tilley 498S substation to 240 kV with one 240/138 kV transformer and tap onto 1034L between Cassils 324S and Bowmanton 244S	Load – thermal and voltage
Warner Substation	New voltage support device	Load - voltage

There are currently three temporary RAS schemes that require tripping load after the first contingency to mitigate voltage and thermal violations at the Tilley and Warner substations. Additional capacitor banks will be required at Warner to remove one RAS, while a new 240 kV substation expansion at Tilley will remove the other two RAS by introducing a new 240 kV source into the 138 kV system.

Intertie restoration

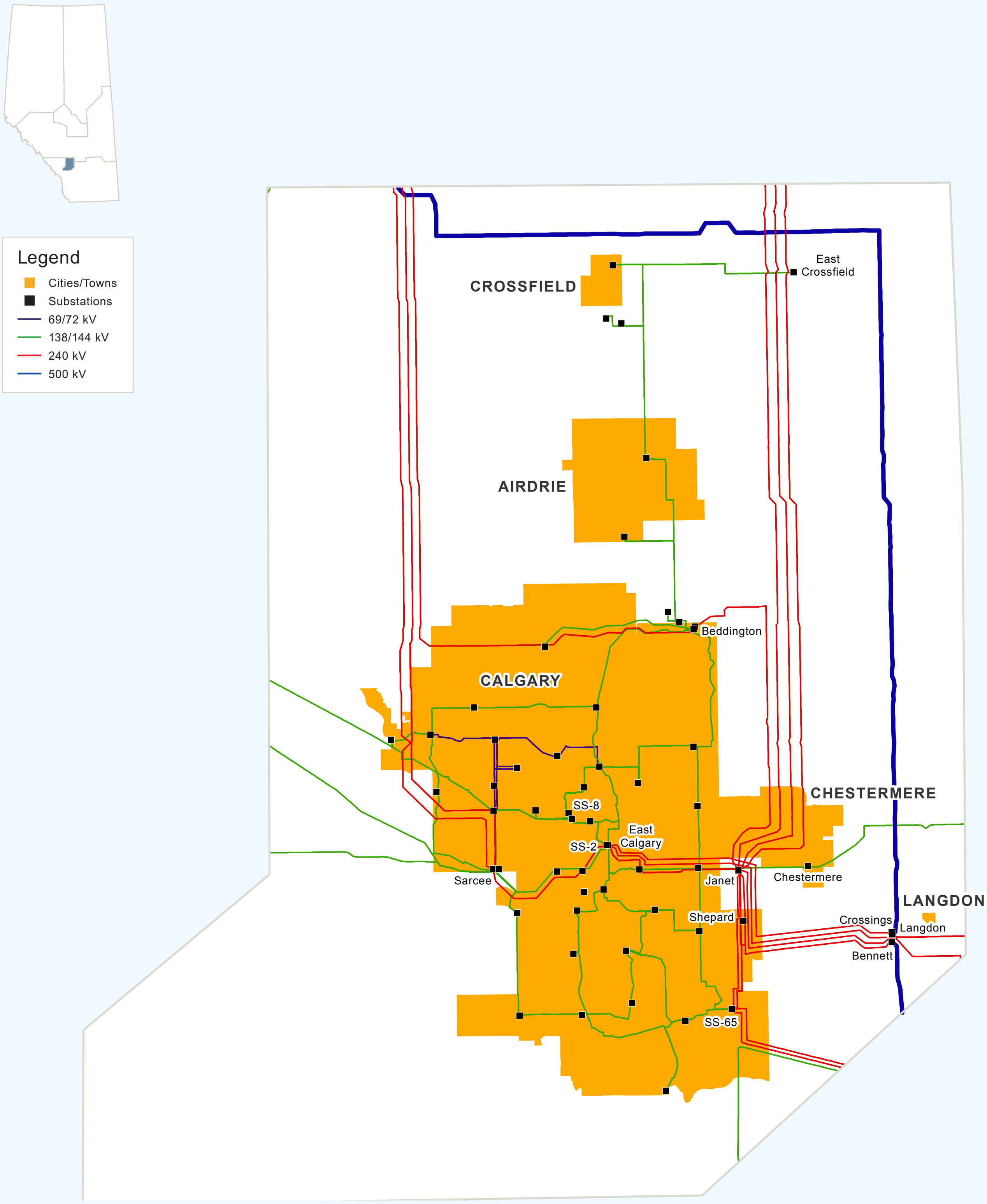
The existing Alberta—B.C. intertie has an import and export capability of 800 MW and 1,000 MW respectively. The existing MATL has an import and export capability of 310 MW and 315 MW respectively. The simultaneous B.C./Montana import capability is limited to 1,110 MW. The T-Reg requires the AESO to plan and make arrangements to restore each intertie to, or near to, its path rating.

The planning for intertie restoration can be described in three blocks:

- **Block One**–includes the installation of a new transformer at Bennett to increase capacity, restoration of the thermal rating of 1201L by mitigating clearance issues for a few spans, and the installation of a series capacitor to help prevent voltage collapse. This block is needed to allow the interties to be scheduled at or near to its path rating and to ensure that the loss of the most severe single contingency (MSSC) does not cause the intertie to trip. The AESO refers to this block as enhancing the loadability of the interties.
- **Block Two**–comprises the CRPC transmission line and reactive support equipment. While the primary driver for CRPC is generation integration, the nature of the CRPC connection also improves the loadability of the interties.
- **Block Three**–addresses the frequency of the Alberta system if the intertie trips while operating at or near the path ratings. Loss of interties at high imports will result in a large drop in system frequency. Currently, the AESO is developing technology-agnostic technical requirements for an ancillary service that would be used to manage frequency performance for intertie trips. This will expand service to allow participation from any technology that can meet the technical requirements including load, energy storage, fast-acting generators or other technologies. The AESO will consider whether installing a back-to-back convertor on the MATL intertie is an economic and technically viable solution, or partial solution, in this block.

CALGARY PLANNING REGION

Existing transmission system



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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, it was summer peaking in 2018 due to an unusually hot summer in the Calgary area.

This 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.

The Calgary Planning Region contains 1,456 MW of generation capacity—all gas fired—including 144 MW of simple-cycle and 1,300 MW of combined-cycle. Generation capacity has increased over the past 10 years, mainly from the Shepard Energy Centre.

The generation forecast for the Calgary Planning Region has only moderate additions of simple-cycle generation.

Table 4.8-11: Calgary regional reference case load and generation capacity forecast

Calendar Year	2018 (MW)	2024 (MW)
Region Peak Load	1,795	1,765
Coal-fired / Coal-to-gas	0	0
Cogeneration	12	12
Combined-cycle	1,300	1,300
Simple-cycle	144	190
Hydroelectric	0	0
Wind	0	0
Solar*	0	0
Other	0	0
Total Generation Capacity	1,456	1,502

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

Existing transmission system

The existing transmission system in the Calgary Planning Region is designed to serve local load and transfer power from major generation centres to Calgary and the surrounding area.

The regional 240 kV network is served by the 500 kV HVDC WATL from the Edmonton–Wabamun Lake area, and six existing north-to-south 240 kV transmission lines that terminate near and in Calgary, one of the major transmission hubs on the grid. Calgary has five main 240 kV supply substations: Sarcee on the west side of the city, East Calgary in the south centre, Janet and SS-65 on the southeast side, and Beddington in the north. The underlying transmission system within the Calgary area consists of 138 kV and 69 kV circuits delivering power to load-serving substations.

In addition, the 500 kV Alberta—B.C. intertie connects to the system near Langdon.

Transmission project status

- **Downtown Calgary Transmission Development**–is a new 138 kV single-circuit line to interconnect the ENMAX No. 2 and ENMAX No. 8 substations. The NID Application is approved by the AUC and the project is expected to be in service in 2021.

Transmission plans

The AESO is currently working with ENMAX to investigate alternatives to mitigate high short-circuit levels in the City of Calgary's downtown area. Substation equipment upgrades or transmission line reconfigurations can be employed to help reduce the short-circuit level observed.

Currently there is a RAS that is designed to trip load connected to Chestermere in the event of thermal overload or under-voltage conditions. These conditions could occur if load grows quickly at Chestermere. To mitigate the potential of tripping load after the first transmission contingency, a new 138 kV transmission line is needed between Janet and Chestermere to mitigate the thermal and voltage concerns.

As additional renewables development occurs in regions south of Calgary, the flow pattern in the Calgary region can be impacted as renewables generation flows north to replace conventional generation, crossing the Calgary Region. This change of flow pattern can further stress the 240 kV backbone system and some of the 138 kV transmission lines that parallel the north-south 240 kV system in Calgary. Additional reinforcement may be needed in Calgary to help manage the change of flow pattern as a result of the changing generation mix within the province.

Table 4.8-12: Developments required to mitigate the identified constraints

Development	Description	Driver
Downtown Calgary Short-Circuit Mitigation	Short-circuit mitigation for downtown Calgary	Load – short circuit
Chestermere Area	New 138 kV line from Janet 74S to Chestermere 491S	Load – thermal and voltage

5.0 Longer-term system plans

Longer-term system plans

The LTP uses a scenario-based approach testing different generation and load assumptions to determine a flexible plan that can respond to uncertainties in pace and magnitude of future load and generation changes.

The objective of longer-term assessment is to provide a high-level vision of potential developments for different prospective shifts in the future. These transmission developments are highly dependent on the pace of load or generation growth in all the regions; however, they are meant to be flexible so that they can be advanced or timed as necessary to address the needs that can arise on the transmission system. Other factors that can influence transmission system developments include pace of:

- Coal-fired generation retirement.
- Renewables generation developments.
- Oil sands development or alternate industries in the province.
- Development of cogeneration facilities.

Scenarios in the 2019 LTO capture the potential trends and are being used to identify possible transmission needs so the AESO can develop a flexible plan that meets the needs of many future scenarios.

The 2019 LTO identified multiple scenarios that represent differing generation and load assumptions regarding the future of electricity supply and demand in Alberta. The 2020 LTP examined five scenarios: Reference Case, High Cogeneration Sensitivity, Alternate Renewables Policy (Faster-Pace Renewables), High Load Growth, and Low Load Growth. As part of the Low Load Growth Scenario, a high DER penetration sensitivity is also developed. By examining these scenarios and sensitivities, various transmission developments can be identified based on different potential outcome in generation and load.

The LTO's Diversification Scenario focuses on changes in industry type within the Alberta economy, and is not expected to have a major influence on identified transmission enhancements as the overall differences in load and generation in all regions are covered by the other studied scenarios. Therefore, the 2020 LTP did not perform studies for the Diversification Scenario.

Overall, with focus placed on the bulk transmission system, the longer-term assessment considers only 500 kV and 240 kV level contingencies. However, the 138/144 kV system is also monitored for any thermal or voltage violations, and in specific situations investigated to also provide a high-level plan to provide reliable long-term supply to an area.

For detailed generation and load assumptions of each scenario, please refer to the 2019 LTO at *www.aeso.ca/grid/forecasting.*

Reference Case

South Planning Region and Calgary Planning Region

There are no additional load-driven transmission needs observed beyond what was identified in the near-term assessment. As part of the intertie restoration project, the third and last block that fully restores the intertie to the original 1,200 MW capability is forecast to take place in the medium term. If the MATL back-to-back HVDC converter is chosen as a solution to Block Three frequency requirements for intertie restoration, this development will take place in the South Planning Region.

Central Planning Region

There are no additional load-driven transmission needs observed in the longer term. The approved PENV transmission development reinforces the area and mitigates the local overloads identified in the previous LTPs. The PENV development will initially be energized at the 138 kV level for the near term. The milestone trigger to convert to 240 kV operation to provide additional capabilities to the region is forecast to take place in the medium term. For the CETO development as outlined in Section 4.5, the second stage of the project will be triggered by a milestone associated with committed renewables developments. The timing of this trigger is forecast to take place in the medium- to long-term time period. The timing could be advanced if the pace of renewables generation progresses faster than forecast.

Edmonton Planning Region

The near-term assessment for the Edmonton Planning Region has identified a need for additional 500/240 kV transformation capacity. There are also 240 kV thermal violations observed; however, they can be resolved by the use of existing operational measures, including: open the bus tie breaker at Bellamy without putting load at risk; 240 kV line reconfiguration; Keephills phase-shifting transformer operation; or EATL and WATL re-dispatch. Even though the operational measures continue to be sufficient in removing the 240 kV overload in the long term, the increased reliance on operational measures long term reduces the system's flexibility to respond to other contingencies elsewhere. Therefore, a longer-term solution that provides strong reinforcement and additional operational flexibility should be considered. Options include:

- Build a 500 kV line between the Keephills substation and Sundance substation so that more power flows toward Sundance and on to north Edmonton, to relieve the loading at Ellerslie.
- Build a new 240 kV circuit between the Ellerslie substation and Argyll in-out connection point, and connect it with the existing 1055L that goes into Argyll. Bundle the existing 1055L transmission line to the existing 908L transmission line from the Petrolia substation to the Argyll in-out connection point. Re-conductor the remaining portion of 908L from the Argyll in-out connection point to the Ellerslie substation.
- Reconfigure the 240 kV system between and around the Sundance and Keephills generation plants.

The 500 kV development between Sundance and Keephills can help resolve both 500/240 kV transformation needs as well as the 240 kV overloads. Alternatively, additional 240 kV reinforcement in the southern Edmonton Planning Region can also mitigate 240 kV overloads; however, this alternative does not provide system and operational benefit at the same level as the Sundance—Keephills 500 kV development. The AESO will continue to monitor this situation and propose the required upgrade at the appropriate time.

Northwest and Northeast Planning Regions

There are no additional load-driven transmission needs observed beyond what was identified in the near-term assessment. Depending on the location and pace of generation developments, other transmission upgrades may be needed to connect the new facilities and enable bulk system transfer.

High Cogeneration Sensitivity

The High Cogeneration Sensitivity Scenario focuses on the Fort McMurray area in the Northeast Planning Region, which is the heart of oil sands operations in Alberta. The primary purpose of these cogeneration units is to supply steam for the local oil sand operations while excess power is sold to the electricity market. Under the scenario, a total of 1,900 MW of additional cogeneration developments is forecasted by 2039 for the Northeast. This is much higher than the 500 MW forecast under the Reference Case; therefore, the 2020 LTP studied the scenario to evaluate the impact of incremental cogeneration integration for the Northeast.

The existing transmission system in the Northeast Planning Region, including the 500 kV FMW transmission line, is capable of accommodating 500 MW of additional conventional generation in the Fort McMurray area. With 1,900 MW of additional cogeneration in the forecast, the following components are potentially required:

- Upgrade the existing 240 kV line from the Dover to Birchwood Creek substations.
- Build a new 500 kV line between the Heartland and Thickwood Hills substations (FME).

The 240 kV upgrade is capable of providing approximately 300 MW of additional transfer capability. Separately, the 500 kV FME transmission line is capable of adding approximately 1,300 MW of additional transfer capability. The actual pace of cogeneration developments in the area will drive the timing and selection of the transmission developments.

Alternate Renewables Policy

The 2020 LTP considered two different paces of renewables development. Under the Alternate Renewables Policy Scenario, also referred to as the “Faster-Pace Renewables Scenario,” there are more renewables connecting to the grid. To enable these anticipated renewables beyond the capability provided by CETO and CRPC, the AESO has investigated a number of alternatives to determine the most effective plan. The alternatives investigated include:

- EATL bi-pole (converting the existing EATL HVDC from today’s mono-pole operation to bi-pole operation by adding additional converters and voltage support devices at the two terminals).
- ECW, PBEC and GLEC 240 kV lines.
- FATDW 240 kV line.
- SS65 to Sarcee 240 kV line (a variation of FATDW).
- Anderson to Heartland 500 kV line.

The most effective plan to integrate renewables generation is to convert EATL to bi-pole operation. Currently, EATL is operated in mono-pole mode with approximately 1,000 MW of transfer capability. The conversion of EATL to bi-pole will double the existing transfer capability, enabling additional capability mainly in the southeast area, but will also help the southwest and central east areas by evacuating more power through HVDC to the north and providing relief for the most constrained transfer-out paths out of these regions. The conversion requires only substation facilities; no new DC transmission line addition is required. However, with additional flow on EATL, additional transmission developments will be required in the Edmonton and South Planning Regions to accommodate higher flow. The additions will likely involve additional 240 kV lines as well as 500/240 kV transformers.

High Load Growth

Under the High Load Growth Scenario, the total AIL is forecast to grow up to 17,193 MW. This is about 3,000 MW higher compared to the 2039 load of 14,274 MW for the Reference Case. As indicated in the 2019 LTO, the primary load growth is driven by oil, natural gas, and petrochemical activities. Therefore, the corresponding cogeneration levels are also higher. Both combined-cycle and simple-cycle units are also added earlier in the forecast, with the level of renewables additions marginally lower than the Reference Case.

With significant oil and gas industry load growth, the Northwest Planning Region is impacted significantly and requires more transmission developments to serve the higher load reliably. To serve potential load growth in the region, the following components are potentially required:

- Convert the 144 kV line from 9L11 to Clairmont Lake, as identified in the near-term plan, to 240 kV operation.
- Build a new 240 kV line from the Little Smoky to Big Mountain substations.
- Build new 144 kV lines between the:
  - Big Mountain and Flyingshot substations.
  - Flyingshot substation and a new future 144 kV substation.
  - New future 144 kV substation and Poplar Hills substation.
  - Big Mountain and Thornton substations.
- Build a second 240 kV circuit from the Little Smoky to Fox Creek substations and continue to the Bickerdike substation.

The two 240 kV developments/conversions—one from 9L11 to Clairmont Lake and one from Little Smoky to Big Mountain—serve as the backbone to reinforce supply into the Grande Prairie area. This area is the base of a number of gas-drilling activities; under a High Load Growth Scenario, a large amount of load growth is anticipated in the area. The remaining 144 kV developments identified above serve to further distribute the supply from the main 240 kV backbone to individual substations locally and reinforce the supply into the Grande Prairie Loop area. They also serve as the loop connecting the northern 240 kV backbone (9L11 to Clairmont Lake) and the southern 240 kV backbone (Little Smoky to Big Mountain). Lastly, the second 240 kV circuit between Little Smoky—Fox Creek—Bickerdike is to reinforce the supply into the Northwest Planning Region from the south.

The timing of these transmission developments will depend largely on the pace of load growth in the region. Large conventional generation developments can also impact the timing of the need for the above transmission developments. Under the High Growth Scenario, the above developments are envisioned to be needed in the medium term, and the second Little Smoky—Fox Creek—Bickerdike circuit is envisioned to be needed in the long term.

For the Central Planning Region, there are a number of potential overloads due to higher load on the 138 kV local network with two 240 kV sources. These include the 138 kV systems between Nevis and Coyote Lake, Johnson to Hazelwood, and Brazeau to Keephills. A portion of these 138 kV systems, which are fed on two sides, can overload if the system loses supply on one side. The AESO will closely monitor these areas and will develop appropriate transmission plans to ensure supply remains reliable.

Table 5.0-1: Summary of proposed transmission developments from longer-term scenarios

Scenario	Transmission Developments	Driver
Reference Case	CETO second stage for additional transfer-out capability	Generation - thermal
	PENV 240 kV conversion for additional renewables integration capability	Generation - thermal
	MATL back-to-back HVDC converter (AIR Block Three)	Intertie
	Keephills to Sundance 500 kV line or 240 kV transmission line upgrades in the Edmonton region	Generation - thermal
Alternate Renewables Policy (Faster-Pace Renewables)	Including Reference Case developments Potential EATL bi-pole for additional transfer capability	Generation - thermal
High Load Growth	Including Reference Case developments Significant 240 kV developments are required in the NW for load growth	Load - thermal
High Cogeneration	Including Reference Case developments 240 kV enhancements (Dover to Birchwood Creek substations) and 500 kV FME line between Heartland and Thickwood Hills substations to enhance transfer capability to/from Fort McMurray	Generation - thermal

6.0 Conclusions

Conclusions

A safe, reliable transmission system that has a flexible development plan is critical to the economic well-being and future prosperity of Alberta.

- **Northwest Planning Region**
  - 240 kV developments are needed in the Fox Creek and Grande Prairie areas with additional 240/138 kV transformation capability required at the Little Smoky substation for the near term.
  - As load continues to grow, additional voltage support devices are required in the Grande Cache and High Prairie areas as well.
  - If load grows significantly in the region, the near-term developments can serve as a foundation for a number of additional 240 kV and 144 kV developments to provide reliable long-term supply to the Northwest.
- **Northeast Planning Region**
  - If significant cogeneration developments take place for the oil sands in the Fort McMurray area, construction of the approved FME 500 kV line, together with a 240 kV transmission line upgrade will be required to accommodate the developments.

Transmission reliability is the ability of the transmission system to withstand sudden disturbances or the unanticipated loss of facilities on the system.

- **Edmonton Planning Region**
  - The City of Edmonton's 72 kV system is reaching its limit. The AESO continues to work with the TFO to determine the best plan for reliable long-term supply into the city.
  - Additional 500/240 kV transformation is also needed in the near term for the 500 kV KEG loop to help alleviate overloads observed on the existing transformers at the Ellerslie substation.
  - Depending on the pace of coal-to-gas conversion, the pace of renewables developments, and the potential to connect additional conventional generation in the Wabamun Lake area, additional 500 kV developments near Sundance or 240 kV transmission line developments are required.
- **Central Planning Region**
  - The 240 kV CETO development is required to accommodate additional renewables development in the region.
- **South Planning Region**
  - In addition to projects related to renewables integration and intertie restoration, load growth at and near the City of Lethbridge is expected to require an additional voltage support device, as well as transmission line upgrades for two 138 kV lines in the area.
- **Calgary Planning Region**
  - The AESO is currently investigating the potential need to mitigate high short-circuit levels downtown and a plan will be provided in the near future.
- **Renewables Development**
  - Depending on the location and pace in the south and central east areas, various stages of CETO or CPRC will also be needed to enable timely integration of renewables generation. These two transmission developments are staged with milestones; the implementation of various components will be triggered when required.
  - Depending on the pace, additional transmission developments may be required in the South and Edmonton Planning Regions. Currently there a number of RAS that trigger load shed after the first contingency. To mitigate the need for these RAS and to help strengthen the system locally, capacitor banks and 138 kV and 240 kV transmission developments may be required.
- **Technology Development**
  - As emerging technologies continue to evolve and become more available at a lower cost, the 2020 LTP also investigated the potential impact of large-scale DER integration in the urban centres as well as the potential impact of additional energy storage facilities. Even with a stretched assumption, the transmission system is expected to handle the potential technology evolution.

7.0 Glossary of terms

Glossary of terms

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).

Alberta Utilities Commission (AUC): The provincial body accountable for regulating the utilities sector, natural gas and electricity markets.

Alternating current (AC): A current that flows alternately in one direction and then in the reverse direction. In North America, the standard for alternating current is 60 complete cycles each second. Cycles per second is also referred to as Hertz (Hz).

Ancillary services: Services necessary to support the transmission of energy from resources to loads based on consumption (for loads) and dispatch (for suppliers).

Behind-the-fence load (BTF): Industrial load served, in whole or in part, by onsite generation built on the host's site.

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

Bulk transmission system: The integrated system of transmission lines and substations that delivers electric power from major generating stations to load centres. The bulk system, which generally includes 500 kilovolt (kV) and 240 kV transmission lines and substations, also delivers/receives power to and from adjacent control areas.

Bus (busbar): Electrically conductive structures in a substation to which elements such as transformers or transmission lines are connected.

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

Capacitor/capacitor bank: A device used to control voltages by eliminating a voltage drop in the system.

Capacity: The amount of electric power delivered or required for a generator, turbine, transformer, transmission circuit, substation or system as rated by the manufacturer.

Circuit: A conductor or a system of conductors through which electric current flows.

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.

Congestion: The condition under which transactions that electricity market participants wish to undertake are constrained by conditions on the transmission grid.

Constraint: A restriction on a transmission system or segment of a transmission system that may limit the ability to transmit power between various locations.

Distributed energy resources (DER): Electrical generation and storage performed by a variety of small, grid-connected devices, generally with capacities of 10 MW or less and located close to the load they serve.

Distribution facility owner (DFO): Entities that own and operate distribution lines, the portion of the Alberta electrical system operating at 25 kilovolts (25,000 volts) or less. These distribution lines provide service to most consumers, except for some very large industries that are directly connected to the transmission grid.

Gas turbine: See simple-cycle.

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.

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

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.

Gross Domestic Product (GDP): One of the measures of national income and output for a given country's economy. GDP is defined as the total market value of all final goods and services produced within the country in a given period of time (usually a calendar year). It is also considered as the sum of the value added at every stage of production (the intermediate stages) of all final goods and services produced within a country in a given period of time and is given a monetary value.

High voltage direct current (HVDC): The transmission of electricity using direct current.

Interconnection or transmission interconnection: An arrangement of electrical lines and/or transformers that provides an interconnection to the transmission system for a generator or large commercial or industrial customer.

Intertie: A transmission facility or facilities, usually transmission lines, which interconnect two adjacent electric systems and allow power to be imported and exported.

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

Load factor: A measure of the average load, in kilowatts, supplied during a given period. It is generally used to determine the total amount of energy that would have been used if a given customer's maximum load was sustained over an extended period of time and, through comparison, show what percentage of potential load was actually used.

Looped system (loop): A system of power lines in which circuits are contiguously connected between substations and then back to the same substation.

Megawatt (MW): An electrical capacity unit of measure equal to one million watts of power supply, demand, flow or capacity.

Merit order: In the wholesale electricity market, merit order refers to the list used to dispatch electricity generation to meet demand. The lowest-cost generation is dispatched first.

Needs Identification Document (NID): A document filed by the AESO with the AUC to define the need to reinforce the transmission system to meet load growth, and/or provide non-discriminatory access to interconnect new loads and generators to the system.

Operating reserve: Generating capacity that is held in reserve for system operations and can be brought online within a short period of time to respond to a contingency. Operating reserve may be provided by generation that is already online (synchronized) and loaded to less than its maximum output, and is available to serve customer demand almost immediately. Operating reserve may also be provided by interruptible load.

Parallel path: Electric power flows on all interconnected parallel paths in amounts inversely proportional to each path's resistance. This also refers to the flow of electric power on one electric system's transmission facilities resulting from scheduled electric power transfers between other electric systems.

Peak load/demand: The maximum power demand (load) registered by a customer or a group of customers or a system in a stated period of time. 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.

Peaking capacity: The capacity of generating equipment normally reserved for operation during hours of the highest daily, weekly, or seasonal loads. Some generating equipment may be operated at certain times as peaking capacity, and at other times to serve loads on an around-the-clock basis.

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.

Power pool: An independent, central, open-access entity that functions as a spot market, matching demand with the lowest-cost supply to establish an hourly pool price.

Reactive power: The component of electric power that does not provide real work but is required to provide voltage.

Reliability: The combined adequacy and security of an electric system. Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances such as electric short-circuits or unanticipated loss of system facilities.

Reserve: See "operating reserve."

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 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.

Single circuit: A transmission line where one circuit is carried on a set of structures (poles or lattice towers).

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

Substation/switching station: A facility where equipment is used to tie together two or more electric circuits through switches (circuit breakers). The switches are selectively arranged to permit a circuit to be disconnected or to change the electric connection between the circuits.

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

Thermal overload: A condition where the thermal limit of a piece of electrical equipment such as a conductor or transformer is exceeded.

Transfer capability: The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability can be expressed in megawatts.

Transformer: An electrical device for changing the voltage of alternating current.

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 facility owner (TFO): The owner of the system of high-voltage power lines and equipment that links generating units to large customer loads and to distribution 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.

Voltage: The difference of electrical potential between two points of an electrical circuit expressed in volts. It is the measurement of the potential for an electric field to cause an electric current in an electrical conductor. Depending on the amount of difference of electrical potential, it is referred to as extra-low voltage, low voltage, high voltage or extra-high voltage.

Voltage stability: Operation within acceptable voltage ranges. Normal voltage limits are defined as the operating voltage range on the interconnected system that is acceptable on a sustained basis. Emergency voltage limits are defined as the operating voltage range on the interconnected system that is acceptable for the time sufficient for system adjustments to be made following a facility outage or system disturbance.

Voltage violation: A measured or calculated condition where the voltage at a point on the transmission system is outside the acceptable limits as described in the criteria.

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