AESO 2022 Long-term Transmission Plan

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1.0 Executive Summary

Executive Summary

The 2022 Long-term Transmission Plan (2022 LTP) describes how the Alberta Electric System Operator (AESO) plans to develop Alberta's electricity transmission system over the next 20 years.

The AESO's *Long-term Transmission Plan* (LTP) is the Alberta Electric System Operator's (AESO) 20-year forward-looking blueprint of how the transmission system in Alberta may need to be developed to support the Alberta Interconnected Electrical System (AIES). 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 prosperity of Alberta.

Economic growth in Alberta has been impacted by multiple factors over the last two years, however the main driver has been the economic impact due to the COVID-19 pandemic. The pace of energy transformation has accelerated in Alberta, where the electricity sector continues to shift away from coal-fired generation to gas-fired generation and increased discussions of the hydrogen economy continue to become more prominent in the province. The pace of renewables development has also accelerated. Many Distributed Energy Resources (DER) projects and large renewables developments with Power Purchase Agreements (PPAs) are looking at aggressive schedules where the construction of generation facilities is able to be completed more quickly than the construction of potentially needed transmission. The new renewable generators are based on power electronics and have different fault response and frequency response characteristics from conventional generators. The shifting supply mix is starting to impact the frequency performance of the system and driving down short circuit levels.

The 2022 LTP seeks to optimize the use of the existing transmission system, and to provide guidance related to the pace and type of transmission developments anticipated in the future to provide for the safe and reliable electricity system. Line upgrades, utilization of Remedial Action Schemes (RAS), use of power flow control devices and other optimization approaches are first considered before looking at the need for additional transmission in Alberta.

In addition to considering the pace and type of transmission required, the 2022 LTP considers how forecasting inputs may impact need and timing by using different scenarios that allow for development of a resilient, yet flexible, plan. The pace of transmission developments will depend on the pace of load growth as well as the pace, location, and type of future generators connected to the system.

The four scenarios from the *2021 Long-term Outlook* (LTO)[1] that are studied in the 2022 LTP include:

- **Reference Case**–as the AESO's base case for planning the system in the near term (five-year horizon, up to 2026) and one of the scenarios for the longer term (more than five years), the Reference Case enables the AESO to investigate the transmission needs aligned with the current policy and regulatory landscape, technological advancements and the most-predominant economic outlook for Alberta.
- **Clean Tech Scenario**–represents a faster pace in decarbonization, electrification and cost reductions in renewables that accelerate changes in the electricity sector toward low-emissions and more DER technologies.
- **Robust Oil and Gas Demand**–allows the AESO to investigate the impact of an aggressive growth outlook for Alberta's energy sector on the transmission system.
- **Stagnant Global Oil and Gas Demand**–allows the AESO to investigate the impact of economic stagnation in Alberta due to muted investment in the oil and gas sector on the transmission system.

All transmission projects identified in the 2022 LTP will undergo further review prior to being considered to progress towards needs filing for Alberta Utilities Commission (AUC) approvals 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.

[1] https://www.aeso.ca/assets/Uploads/grid/lto/2021-Long-term-Outlook.pdf

1.1 2022 LTP HIGHLIGHTS

Near-term Regional Transmission Plan Highlights

The following regional highlights summarize transmission system developments that could potentially need to be filed to the AUC for approval over the next five years:

- **Northwest Planning Region:**
  - 144 kV transmission line in the Grande Prairie area to support load growth in the Grande Prairie region.
  - Additional transformation capacity in the Valleyview area to support load growth in the Valleyview, Grande Prairie, and Grande Cache areas.
  - Voltage support devices in the Grande Prairie and Grande Cache areas.
- **Northeast Planning Region:**
  - 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 and address ageing infrastructure.
- **Central Planning Region:**
  - No new projects identified; the future timely construction triggering based on congestion forecasts of the Central East Transfer Out (CETO) and Provost to Edgerton and Nilrem to Vermillion (PENV) projects is expected to meet the need of the region.
- **South Planning Region:**
  - New 500 kV Chapel Rock substation, new 240 kV transmission line and voltage support device to increase generation integration capability in the Southwest and help restore Alberta-B.C. intertie.
  - New 240 kV transmission line from the Medicine Hat area to the Lethbridge area to provide additional generation integration capability.
  - New 240 kV substation and new 138 kV line to support load growth in the Lethbridge area.
  - Increase capacity of 138 kV transmission lines in Medicine Hat and Vauxhall areas to provide additional generation integration capability.
  - New 138 kV transmission line in the Sheerness area.
  - Additional transmission enhancement to help restore Alberta-B.C. intertie.
  - Montana–Alberta Tie Line (MATL) high-voltage direct current (HVDC) back-to-back converter to isolate Alberta from Montana.
- **Calgary Planning Region**
  - No new projects identified.

Longer-term Regional Transmission Plan Highlights

Longer-term regional transmission system developments are those projects that could potentially need to be filed to the AUC for approval beyond the next five years.

For the longer-term, upgrades to an existing 240 kV line in the Fort McMurray area may be required under the Reference Case scenario. While there are no new transmission projects identified under the other scenarios for the longer-term, it is anticipated that generation-driven transmission projects already identified may need to be advanced depending on the pace and location of generation developments.

1.2 INVESTMENT POTENTIAL

With the goal of optimizing the transmission system and only triggering the construction of transmission projects when specific milestones are met, the construction timing of the projects identified in the 2022 LTP may vary. Several projects that totaled nearly $1 billion in the 2020 LTP have already been deferred by several years within the 2022 LTP as a result of this optimization.

The overall potential investment range identified within the 2022 LTP over the next 10 years is in the range of $150 million to $200 million per year on average. Based on the Reference Case, no new major projects will be added until 2025 at the earliest. The cumulative transmission rate impact of the projects identified in the LTP is approximately $2/MWh for the first five to eight years with a potential cumulative increase of $3/MWh after 15 years. These transmission projects would add approximately $1 to $2 per month to an average residential customer. Based on the Clean-Tech scenario with accelerated renewables integration, the transmission projects driven by generation integration could be required earlier.

2.0 Background and Objectives

Background and Objectives

The AESO works with industry partners to keep electricity flowing throughout the province. As a not-for-profit corporation mandated by legislation to act in the public interest, the AESO is prohibited from holding an interest in any transmission, distribution or generation assets.

The AESO is required by provincial legislation[2] to operate the transmission system in a safe, reliable, and economic manner and plan a transmission network that meets current and future electricity requirements in order to support and enable Alberta's economy.

The AESO meets its legislated duties by:

- Determining future requirements of the provincial grid, identifying transmission system enhancements needed to meet those requirements, and arranging to implement those enhancements in a timely and efficient manner and in accordance with statutory obligations.
- Preparing and maintaining a transmission system plan that forecasts, on a 20-year horizon, system conditions and requirements to accommodate future load growth and anticipated generation additions, as determined in the AESO's LTO.
- Directing the safe, reliable and economic operation of the interconnected electric system.
- Operating the power pool and facilitate the electricity market in a manner that is fair, efficient, and openly competitive.
- Providing transmission access service consistent with an approved transmission tariff.
- Managing and recovering the costs associated with line losses and ancillary services.
- Conducting 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.

2 https://open.alberta.ca/dataset/75840897-ea65-46aa-9a71-23f84df86e9d

The objective of the 2022 LTP is to present the AESO's future view of how the Alberta's electric transmission system may need to be developed to support various future scenarios of Alberta's economic and energy outlook over the next 20 years, including those developments that may be required to meet the need of emerging changes.

The 2022 LTP is designed to:

- Optimize the use of the transmission system to defer transmission developments and highlight that the AESO is focused on the efficiency and optimization of the existing grid, finding ways to meet identified transmission needs while minimizing costs.
- Identify transmission facilities that may be needed to address near-term needs and provide a future view on how the transmission system may evolve for the longer-term to ensure continued reliability.
- Enable reliable transition from coal-fired generation by monitoring the gradual phase-out and replacement of existing coal-fired generation facilities and its impact on transmission system reliability.
- Enable integration of new technological advancements such as the development of DER in urban areas, integration of energy storage, and higher integration of solar facilities, electric vehicles (EV), and energy storage facilities.
- Provide guiding locational signals to generation developers to where transmission system capability is available and planned, in order to ensure economically and timely developments of resources and transmission system infrastructure.
- Satisfy the AESO's mandate according to the Transmission Regulation and Electric Utilities Act[3] to provide an update every two years.

[3] https://open.alberta.ca/publications/e05p1

3.0 Stakeholder Consultation and Engagement

Stakeholder Consultation and Engagement

The AESO is continuously engaging with industry and stakeholders across the province to ensure all voices are heard when prioritizing transmission projects.

The AESO engages Albertans across the province to understand concerns and learn what issues are at the forefront when developing its LTP. These consultations provide us with broad perspectives and valuable input used to assist the AESO in establishing forecast scenarios and corresponding transmission planning results.

The AESO has spent the past year conducting targeted consultations and information sessions with transmission facility owners (TFOs) and distribution facility owners (DFOs) to gain valuable insight about upcoming projects and to learn about potential issues that could impact the electricity value chain.

The AESO recognizes that stakeholder experience and expertise is valuable, and these ongoing discussions help to inform and 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 accordance with the *AESO's Stakeholder Framework*[4], feedback is regularly sought to ensure the needs and interests of all groups are consistently, transparently and meaningfully considered.

For future material system developments, the AESO will work with interested stakeholders by sharing information about screening alternatives considered, reasons for screening out alternatives and the rationale for choosing the alternatives we intend to commit resources to further investigation as viable potential alternatives to meet the need identified. The objective of the engagement is to inform stakeholders, seek any input on the rejected alternatives or any other alternative a stakeholder may offer to ensure that the AESO has not missed any important alternative in addressing the need identified for the project and to share information about how the viable potential alternatives were chosen. Upon completing the viable potential alternative analysis, we would again work with interested stakeholders to inform them of our recommended alternative, why we consider it to be the best overall alternative to meet the need, and why the other alternatives are not chosen. These would be completed prior to filing system Needs Identification Documents (NIDs) with the AUC for transmission projects that meet certain thresholds. The AESO has shared this potential approach with stakeholders as part of the system project update information session with stakeholders in October 2021. The AESO will continue to develop and refine the process with stakeholder feedback once the AESO has the first few opportunities to work with stakeholders.

[4] https://www.aeso.ca/stakeholder-engagement/engagement-framework/

4.0 Forecasting and Planning Process and Methodology

Forecasting and Planning Process and Methodology

Alberta's electricity market determines investment in generation; the Long-term Outlook (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 long-term forecast, the 2021 LTO, was published in June 2021 and is a key input for the 2022 LTP. Key elements of the 2021 LTO are outlined in this section and more details and data from the 2021 LTO are available on the AESO's website.

The 2021 LTO was developed during a period of uncertainty and transformation of Alberta's electricity industry. Changes in economics, policies, technology, consumer preferences, 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 2021 LTO presented a set of four scenarios to capture possible futures states of Alberta's electricity supply and demand.

Table 1: 2021 LTO Scenarios at a Glance

Reference Case	Scenario that tests the impact of the current policy and regulatory landscape, technological advancements and the most-predominant economic outlook for Alberta. This scenario serves as the main corporate forecast
Clean-Tech	Scenario that tests an upside to trends in decarbonization, electrification and cost reductions in renewables that accelerate grid changes toward low-emissions and greater DER technologies
Robust Global Oil and Gas Demand	Scenario that tests the impact of an aggressive growth outlook for Alberta's energy sector
Stagnant Global Oil and Gas Demand	Scenario that tests the impact of economic stagnation in Alberta due to muted investment in the oil and gas sector

4.1 2021 LTO DRIVERS AND ASSUMPTIONS

The 2021 LTO examines the impact of these scenarios by modifying the following three broad groups of drivers and assumptions: economy, policy, and technology.

Economic inputs into the 2021 LTO include the impact of the global COVID-19 pandemic, long term economic forecasts from the Conference Board of Canada, and oilsands production forecasts from IHS[5]. The Robust and Stagnant Oil and Gas scenarios adjust the economic and oilsands outlooks to assess the impact on both generation and load. The Clean-Tech scenario also adjusts economic inputs but has more of a focus on policy and technological drivers.

Carbon policy affects the economics of all generation technologies. Due to an increasingly stringent carbon policy and corporate Environmental, Social and Governance (ESG) mandates, Alberta is expected to have more corporate PPAs associated with renewable generation. The Clean-Tech scenario focuses on these policy drivers by increasing the carbon price and the size of the corporate PPA market to test the impact on generation development over the forecast horizon.

Technology drivers include the adoption rate of DER, electric vehicles, and energy storage. The Clean-Tech scenario focuses on these drivers by increasing the rate of adoption to test the impact on the system.

2021 LTO Forecast Methodology

The 2021 LTO forecasting process reflects the most up-to-date information and incorporates best practices in forecasting methodology. The overall forecasting process was informed and validated through consultations with stakeholders including industry groups, research institutions, academia, market participants and DFOs.

The AESO connection process project inclusion criteria determine which specific load and generation projects are added to the 2021 LTO forecast. The projects that meet inclusion criteria are prevalent in the initial years of the forecast. Further out into the forecast horizon, additional projects are assumed to be generic (i.e., they do not correspond to specific projects in the AESO connection process). Addition of these generic projects is based on methodologies unique to load, generation, DER, or energy storage, that are explained next along with the methodology for forecasting EVs.

Table 2: Overview of the 2021 LTO Forecasting Methodology

Load Forecasting	This is based on econometric modelling across different load hierarchies: Alberta internal load (AIL), planning regions, planning areas and every individual point of delivery (POD)
Generation Forecasting	Market entry is modelled based on supply and demand fundamentals and expected economic returns across different types of thermal and renewable technologies. Market entry is also added based on expected external market forces such as Corporate PPAs and cogeneration. Retirements are based on policy or announced projects
DER Forecasting	The 2021 LTO forecast for DER technologies (solar, wind, and gas) is based on the 5 MW threshold. DER less than 5 MW are forecast based on historical trends and adoption rates. DERs 5 MW or larger are forecast based on the generation forecast methodology described above
Energy Storage Forecasting	The 2021 LTO forecasts increasing amounts of energy storage, based on extrapolated trends. The energy storage volumes in the 2021 LTO are added exogenously to the forecast model
EV Forecasting	EV penetration is based on different consumer adoption rates. Charging profiles are assumed to vary between winter and summer months as well as day of week (weekdays vs weekend driving patterns)

[5] A summary of the IHS Markit Outlook can be found here: https://ihsmarkit.com/research-analysis/canadian-oil-sands-running-above-prepandemic-highs.html

New Supply Location

For the purposes of transmission system planning and to fulfill the requirements of the Electric Utilities Act (EUA)[6] and Transmission Regulation[7], locations are assumed for future generic generation developments that are not associated with a specific project. For those projects that meet the AESO's project inclusion criteria and are included in the LTO, locations are already known and do not need to be assumed.

When locating future generic generation development, the AESO considers utilizing existing infrastructure (such as brownfield sites), energy resources (such as the location of strong wind and solar resources), future planned transmission enhancements, and developer information. Importantly, within each region, unit-specific locations are assigned to utilize the existing transmission system capability and minimize the need for transmission reinforcements. Should actual generation connect in locations less optimal than those assumed in the LTP, timing of potential transmission developments will be impacted.

Generic wind and solar generation additions are spread across the AESO's South and Central Planning Regions based on a combination of the resource potential in those areas and the current projects in the connection process.

Generic combined-cycle additions are assumed to occur at brownfield coal sites. Brownfield sites have the benefit of existing infrastructure and lower development costs and there are several projects that have proposed building combined cycle at existing coal sites. Simple cycle additions are assumed to occur both at brownfield sites and at greenfield sites within regions with proposed projects. The benefits of brownfield sites mentioned for combined cycle would also apply to simple cycle. Greenfield sites can have the benefit of locating closer to the gas fuel source and there is interest in the project list to develop greenfield simple cycle gas projects.

Generic cogeneration developments are primarily assumed to occur within the established oil sands production areas of Fort McMurray and Cold Lake.

For simple cycle, wind and solar, both transmission-connected and distribution-connected sites are modelled. The actual location of future wind, solar, combined cycle, simple cycle and cogeneration, including their development timeframe, will ultimately depend upon developer decisions. The locations of generators stated within the 2021 LTO represent reasonable assumptions, based on where the best potential resources are available.

4.2 2021 LTO FORECAST OUTCOMES

The 2021 LTO Reference Case was used as the base case for both the near-term and longer-term 2022 LTP assessments. The Clean-Tech, Robust and Stagnant Global Oil and Gas Demand scenarios are only studied in the long term in the 2022 LTP because the differences between those scenarios and the Reference Case are immaterial in the near term.

2021 LTO Reference Case

Load

The Reference Case load forecast indicates that AIL growth has entered a relatively slow and steady growth phase due to a number of factors. The Alberta economy is expected to maintain a slightly downward trend for electricity intensity, as established sectors of the economy (e.g., bitumen production, manufacturing) improve their energy efficiency and new incoming industries are less energy intensive. The impact of restrictions due to the COVID-19 pandemic's public health measures is forecast to restrain AIL growth in the near term as the province turns the corner on the pandemic. Lastly, and more relevant to the medium-and long-term prospects, load growth is

[6] https://www.qp.alberta.ca/documents/Acts/E05P1.pdf

[7] https://www.qp.alberta.ca/documents/Regs/2007_086.pdf

projected to follow a slower-paced upward trend due to small-scale expansion at oil sands sites, slower gross domestic product (GDP) growth, as well as increased penetration of DER and general energy efficiency gains. The combination of these factor results in AIL growing at a compound annual growth rate of 0.5 per cent, from 2021 to 2041.

Generation

The Reference Case forecasts the development of 12,193 MW of new or substantially modified generation in Alberta over the next 20 years. The near term sees a large increase in both renewable and thermal generation driven by recently announced projects that have met the AESO's project inclusion criteria. The longer term (post 2026) sees more modest generation additions including both renewable and thermal additions.

Near-term projects in the LTO include natural gas-fired projects like the Suncor coke boiler replacement cogeneration project and the Cascade combined-cycle project. In addition to these specific thermal projects, most of the historical coal fleet is expected to convert their coal boilers to natural gas operation. A significant number of renewables projects are also included in 2021 and 2022, including 718 MW of solar projects and 1,547 MW of wind projects.

Once the near-term projects are built out, combined-cycle natural gas generation is expected to see an additional 1,437 MW of capacity built while simple-cycle natural gas generation is expected to see an additional 446 MW of capacity built by 2041. This capacity will replace the retiring coal to gas fleet and in part meet load growth. In addition to the Suncor boiler replacement, there is an additional 675 MW of cogeneration forecast to complement greenfield oil sands projects. After the renewable buildout from projects in 2021 and 2022 there is an additional 300 MW of solar and 1580 MW of wind capacity expected to be developed from corporate PPAs and DERs. The Reference Case also includes 150 MW of new battery storage projects by 2041.

2021 LTO Clean-Tech Scenario

Load

The Clean-Tech load forecast represents a boundary condition that tests a major departure of the traditional load drivers and profiles experienced in Alberta to date. Lower oil sands production and economic growth reduces the pace and magnitude of AIL growth over the entire forecast period. Greatly offsetting remaining AIL growth is the rapid pace of DER adoption – particularly the expected increase of rooftop solar to over 2,051 MW by 2041. This combined effect of lower general growth and the addition of DER generation results in slower AIL growth until the mid-2030s when compared to the Reference Case. In the latter half of the 2030s, the cumulative impact of EV charging – with EVs assumed to reach one-third of the entire vehicle stock in Alberta – pushes AIL growth well above the Reference Case by 2041. The overall impact of these drivers translates into an AIL growth rate of two per cent per year, where most of the growth is expected to accelerate from the mid-2030s onwards.

Generation

The Clean-Tech scenario generation forecast sees a large shift towards renewables and emerging technologies like energy storage compared to the outlook for the reference case.

The higher carbon price, larger corporate PPA market, and decreased solar and wind costs contributes to a 1,680 MW increase in solar capacity and a 540 MW increase in wind compared to the reference case by 2041. Energy storage increases by 1,370 MW in the scenario compared to the reference case, driven by cost declines. While the Clean-Tech scenario forecasts a continued decrease in emissions, the scenario does not contemplate Alberta's electricity sector reaching net zero emissions during the forecast horizon. Please see the 2021 LTO report for details on emission projections across all the scenarios.

Natural gas additions also increase by 1,387 MW compared to the Reference Case, consisting of 515 MW of incremental simple-cycle, 737 MW of incremental combined-cycle, and 135 MW of incremental cogeneration capacity. Natural gas additions displace retired coal and coal-to-gas capacity, since the relative economics of newer natural gas technologies are much more attractive under the higher carbon prices depicted in this scenario. The increased amount of natural gas-fired generation aids in providing fast-acting supply to counteract the modified daily load patterns caused by increased on-site solar generation and EV charging load.

2021 LTO Robust Global Oil and Gas Demand

Load

The Robust Global Oil and Gas Demand scenario is predicated on crude oil prices rebounding and remaining strong in the long term. It also envisions an expansion of existing Alberta oil sands facilities and the development of new oil sands projects, many of which were previously postponed or deferred. This has a direct positive impact on load in the northeast and central east part of the province. The increase in oil sands activity leads to higher economic growth in Calgary and Edmonton as well as increased load growth in other regions. The overall impact of these drivers translates into an AIL growth rate of 0.8 per cent per year, reaching levels eight per cent higher than the Reference Case by 2041.

Generation

Generation development is higher for the Robust Global Oil and Gas Demand scenario compared to the Reference Case. Higher oil sands development drives approximately 1,000 MW of additional cogeneration development in the oil sands sector by the end of the forecast term. These cogeneration developments are assumed to be a combination of SAGD (steam-assisted gravity drainage) greenfield oil sands projects and existing sites installing additional cogeneration to replace existing boilers.

2021 LTO Stagnant Global Oil and Gas Demand

Load

The Stagnant Global Oil and Gas Demand scenario translates into reduced energy consumption levels across multiple sectors in Alberta. The ripple effect of lower oil sands production results in lower economic activity and therefore moderate, and in some years, slightly negative load growth across various regions. Unlike the rest of the 2021 LTO scenarios, the Stagnant Global Oil and Gas Demand scenario produces an inverse-U shape load forecast, whereby forecast values increase slowly after 2021 but gradually decrease after reaching a peak in the mid-2020s.

Generation

The Stagnant Global Oil and Gas Demand scenario represents a future without a need for significant growth-driven generation capacity. Most of the new generation in this scenario replaces retiring generation. Simple-cycle and combined-cycle replaces retiring coal-to-gas in the 2030s. Combined-cycle growth remains lower than the Reference Case, with two new units, comprising 958 MW of capacity, expected to come online in the late 2030s. Simple-cycle development sees an increase relative to the Reference Case due to coal-to-gas units retiring earlier. Renewable generation additions are lower in this scenario, with 2,377 MW of incremental wind and 1,018 MW of solar added throughout the long-term forecast.

4.3 TRANSMISSION PLANNING AND DEVELOPMENTS

Transmission Planning Process

The AESO's LTP process is completed every two years by performing an analysis of the transmission system over a 20-year planning horizon using key forecast assumptions to identify possible future reliability issues and to identify potential required transmission plans to address those forecasted reliability issues.

The planning process relies on various key inputs, forecasts and assumptions. The AESO examines load growth and potential generation development and retirements. The 2022 LTP focuses on transmission developments required to meet forecast load growth, and the shift in Alberta's generation fleet with the ongoing phase-out of coal generation as well as the growing level of renewable electricity development interest in Alberta. As the exact timing and location of future generation developments cannot be determined with certainty, the 2022 LTP uses scenarios outlined within the 2021 LTO to ensure transmission development plans are created to accommodate a range of potential future conditions.

The 2022 LTP assesses the system using two different time frames:

1. **Near-term assessment (Need to be approved within five years)**

   The purpose of the near-term assessment is to examine the transmission system in more detail on a regional basis. The more detailed assessment allows the AESO to understand regional needs over the next five years, a time horizon that has reasonable timing certainty in load and generation development trends. Transmission development plans identified are required to mitigate reliability violations identified over the assessment period. Any transmission plans identified will still need to undergo further detailed needs analysis and alternative evaluation in order for the AESO to decide if a specific project is needed. As part of this needs analysis stage, the AESO will assess the opportunity to optimize the existing transmission system and propose alternate approaches to utilize the existing transmission system where possible and defer the timing of these larger transmission developments. Any required transmission developments will then be brought forward for the AUC's approval. Given the time required for these subsequent steps in the planning and regulatory approval processes, the earliest any of the large projects identified in the near-term plan would be completed is five to seven years in the future. The AESO regularly monitors how the system evolves within the regions and will prioritize the needed system investments to ensure the system remains reliable.

2. **Longer-term assessment (Need to be approved beyond five years):**

   The longer-term assessment examines the transmission system from a bulk, system-wide basis based on a range of future scenarios. It focuses on identifying potential broad and material future reliability concerns for the various LTO scenarios discussed in the forecast section. As such, only outages on the 240 kV and 500 kV system are assessed, and the impact to elements at 138 kV and above are 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 TELECOMMUNICATIONS PLANNING

Alberta's province-wide utility telecommunication network is essential to the reliable, efficient and safe operation of the grid. This sophisticated infrastructure overlays the transmission system and carries critical services used to monitor, protect, and operate the interconnected electric system.

These critical services require the telecommunication network to be highly reliable, highly available and have sufficient communication capability, including speed and volumes. It helps to quickly isolate faulted elements, to maintain system stability, monitor transmission network integrity, protect equipment from unnecessary damage, and allows system operators to respond to changes and take corrective action as needed. Outages on the utility telecommunication network can in turn require outages on the transmission system.

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 primarily 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 and DFOs 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 *2022 Telecommunication Long-term Plan (2022 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 coordination opportunities.

In developing the 2022 Telecommunication LTP, which is primarily an update to the 2020 Telecommunication LTP[8], the AESO evaluated the current and future needs and drivers for the utility telecommunication network. The 2022 Telecommunication LTP aligns with long-term transmission planning, which is a primary 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 radio communications

Projects in the 2022 Telecommunication LTP have been selected to significantly reduce both planned and unplanned outages on the telecommunication network, and therefore improve the reliability and availability of the transmission system with an emphasis placed on improvements to the 500 kV and 240 kV transmission systems. Individual business cases and justification documents are still required to support proceeding forward to execution with any telecommunication projects, on required timelines.

The 2022 Telecommunication LTP lists key projects for the near-term (five-year) and medium-term (10-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 2022 Telecommunication LTP outlines planning guidelines for the following:

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

[8] https://www.aeso.ca/assets/downloads/AESO-2020-Telecommunication-LTP-Final.pdf

5.0 Existing System and Current Transmission Developments

Existing System and Current Transmission Developments

The 2022 LTP is designed with flexibility in mind. As the grid continues to evolve, the AESO will continue to monitor, prioritize and adapt to ensure that transmission facilities are ready and available at the right location and at the right time.

5.1 THE EXISTING SYSTEM AND RECENT UPGRADES

The structure of the grid reflects the historical growth and development of population and industry in Alberta. A backbone of 240 kV AC transmission lines connects Calgary, Red Deer, and Edmonton, the three largest cities in Alberta. Collectively, those cities contribute approximately one third of Alberta's load. Beginning in the 1950s, the Lake Wabamun area near Edmonton became a generation hub, in part due to the coal mining potential. Up to 4,500 MW of coal generation was located in the area. For decades the 240 kV backbone was used to transfer electricity from Edmonton to Calgary and the south.

Beginning in the 1990s, the south region has gradually become a centre for renewable generation and growth of renewable generation has accelerated in recent years. The south is a favourable location for wind and solar generators because of its weather and geography. In the past few years, some coal generators have been retired, and others are anticipated to retire soon as indicated in the 2021 LTO. The retirements are driven partly by asset aging, economics, and legislation addressing carbon emissions in general and coal generators specifically. These changes to the generation fleet have led to a shift in the use of the Edmonton-Calgary transmission backbone. When wind and solar assets are generating energy, power must be transferred north. Dispatchable generators must meet demand when those assets are not generating, and as a result, power transfer is required from north to south.

Two 500 kV HVDC transmission lines, the Eastern Alberta Transmission Line (EATL) and the Western Alberta Transmission Line (WATL), were developed and energized at the end of 2015. EATL and WATL each allow the controllable transfer of up to 1,000 MW either north or south between Edmonton and Calgary. Due to EATL and WATL, the north-south transmission corridor in central Alberta is expected to have sufficient capacity for the AESO's planning horizon. In conjunction with EATL, the Heartland 500 kV Transmission Development, which integrates the north terminal of EATL with the 500 kV system in the Edmonton area, was completed.

Southern Alberta is served by a network of 240 kV transmission lines that provide grid access for many renewable generating facilities and serve electricity consumers in Lethbridge, Medicine Hat, and throughout the south. The most recent major developments in the region are the Southern Alberta Transmission Reinforcement (SATR) and the Foothills Area Transmission Development (FATD). SATR, designed primarily to provide grid access for generators, was approved by the AUC in 2009. Parts of SATR were developed in the subsequent decade. The elements of SATR that were constructed include high-capacity double circuit lines from Windy Flats (near Pincher Creek) to Foothills (south of Calgary) and from the EATL south terminal (near Brooks) to Whitla (south of Medicine Hat). FATD strengthened the connection between Foothills and Calgary, and facilitated the interconnection of Shepard Energy Centre, an 868 MW combined cycle generating station near Calgary that began commercial operation in 2015.

Northeast Alberta is home to oil sand developments that need substantial access to electricity. The region is served by two 240 kV transmission lines that originate northeast of Edmonton, and a 240 kV tie with the Northwest. Continued oil sands development required increased access to electricity infrastructure. To meet this need, the Fort McMurray West 500 kV transmission line was developed, and energized in 2019. Considering the recent addition of the Fort McMurray West line, the AESO anticipates the region's needs will be met for some time.

Several other transmission upgrades have been completed in recent history:

- The South and West of Edmonton project created the Saunders Lake and Harry Smith 240/138 kV substations and integrated them with the transmission system.
- The Red Deer Area Transmission Development implemented 240 kV and 138 kV upgrades in the Red Deer area, including the creation of new 240/138 kV substations near Ponoka, Innisfail, and Didsbury.
- The Hanna Region Transmission Development involved construction of new 240 kV transmission lines from Metiskow to Lanfine to Oakland, creating a 240 kV loop in the Central East.

5.2 PROJECTS IN ACTIVE DEVELOPMENT

The grid has expanded in the last 15 years. However, while the AESO anticipates the pace of development to be materially slower in the near future, several projects are in active development.

The need for the PENV transmission development was approved by the AUC in 2019. The project involves constructing two new transmission lines in the Central East area of the province that will increase the system's capability to integrate additional renewable generation and to serve load in the area. Based on the most recent 2021 LTO, the load in the PENV area has not grown as quickly as originally anticipated in the NID application. At the lower 2021 forecast, the existing system is able to serve the load reliably in the near future thus deferring the load-driven need by a few years. In addition, a congestion analysis was performed to better understand the generation-driven need. With 749L restored to its conductor rating, the existing system can accommodate more renewables generation, and PENV can be deferred for two to three years.

The Facility Applications (FA) of TFOs were submitted for regulatory approval with the Hansman Lake to Edgerton line receiving approval in August 2021 while the application for Nilrem to Vermillion line was denied by the AUC in October 2021. The AESO is working with the TFOs to determine the next steps on the Nilrem to Vermillion line FA.

The Central East Transfer-Out (CETO) project described in the 2020 LTP was approved by the AUC in 2021.[9] CETO will create capacity for generators to connect to the grid in the east side of the province between Edmonton and Calgary. The AESO anticipated that renewable generators connecting in the region will create outflows exceeding the capacity of the existing system and has proposed a 240 kV transmission line from Tinchebray (near the Battle River generating station) to Gaetz (near Red Deer). With regulatory approval, the AESO is monitoring generation development in the region. The pause between regulatory approval and construction is intended to reduce ratepayer costs through deferral while still providing reasonable access for generation projects. At the end of 2021, the upper congestion milestone of the CETO project has been reached. Therefore, the AESO has initiated a congestion re-affirmation study process using the most recent information available, will be arranging a focused working session with stakeholders in early 2022 and will complete the re-affirmation congestion assessment in 2022.

The Chapel Rock-to-Pincher Creek (CRPC) project was conceived to increase the system's capacity to transfer power from renewable generation in the south and strengthen the AB-BC intertie by connecting the 500 kV BC tie line with the Alberta 240 kV network in the south.[10] The project involves creating a new substation and transmission line to connect the Alberta–B.C. intertie with a substation in the Pincher Creek area. The AESO has continued to pursue the project by collaborating with the prospective facility owner to explore siting and routing options. Observing that the system has some capacity for connecting additional generation before the project is needed, the AESO has not yet applied for regulatory approval.

The AESO is developing a transmission project in the City of Edmonton to provide reliable long-term supply to the city. The need for the project and the AESO's plan for system enhancement are discussed in the next section.

In addition to these major projects, the AESO is implementing several smaller upgrades, including the addition of voltage support at Rycroft and the addition of a breaker at North Lethbridge.

5.3 SYSTEM OPTIMIZATION

The 2022 LTP takes a new approach in identifying potential opportunities to optimize the use of the existing transmission system before proposing new transmission developments.

Potential approaches the AESO will use to optimize the existing transmission before proposing large transmission build include:

- Using congestion analysis to integrate additional renewables generation in areas with strong interest.
- Utilizing Remedial Action Schemes (RAS) to disconnect generators to maintain reliability of the transmission system after a contingencies.
- Mitigating minor transmission line thermal constraints, such as resolving line clearance issues, to take advantage of the full conductor thermal rating.
- Investigating the potential use of power flow control devices to re-direct power to less-utilized transmission facilities.
- Investigating the potential use of non-wires solutions, such as energy storage, where appropriate.

9 https://www.aeso.ca/grid/projects/central-east-transfer-out-transmission-development/

10 https://www.aeso.ca/grid/projects/chapel-rock-to-pincher-creek-transmission-development/

5.4 OPPORTUNITY TO CONNECT NEW GENERATION

South and Calgary Regions

Developers have strong interest in connecting generators in the South region, and as evidenced by the connection project list, many connection requests are for wind and solar generators. Developers are motivated to choose the South region for its strong wind and solar resource potential.

The south region can be broadly divided into the Southwest and Southeast sub-regions. Each has distinct challenges with respect to generator interconnection.

The Southwest sub-region is the geographical area west of Lethbridge. The Southwest system is limited in its ability to transfer power to the Calgary load centre. Two main bulk system paths transfer power from the Southwest to Calgary: Windy Flats to Calgary, and Lethbridge – Milo – Langdon. Transmission constraints on the Lethbridge – Milo path have required the AESO to develop remedial action schemes to accommodate generators, and generation on these remedial action schemes is approaching the allowable limit. An updated 2021 assessment using AESO's new congestion analysis showed that the existing system could potentially accommodate another 2,000 MW of renewables generation in the Southwest and Southeast before congestion in the Southwest becomes material.

The plan for increasing system capacity in the Southwest is the CRPC project. The CRPC project will create a third path from the Southwest to the Calgary load centre by connecting the regional 240 kV network with the 500 kV BC tie, which terminates near Calgary. The plan achieves economic efficiency by increasing utilization of existing assets. CRPC is projected to facilitate the interconnection of more than 600 MW of incremental generation near Windy Flats. The AESO will monitor the pace of renewable development in the Southwest and Southeast as part of its timing decision to file the CRPC Need for approval by the AUC.

The Southeast sub-region is the geographical area east of Lethbridge and south of Brooks. The Southeast system comprises the 240 kV double circuit Cassils/Newell (Brooks)– Bowmanton (Medicine Hat)– Whitla path, and 138 kV connections to the Southwest and Central East. Power is transferred out of the Southeast to Calgary by way of the Cassils/Newell – Milo – Langdon path, and to the Edmonton region via EATL. Capacity on EATL is shared with the Central East. Capacity on the Cassils/Newell – Langdon path is shared with the Southwest.

Generator connection capability on the Cassils – Bowmanton – Whitla (CBW) path itself is limited by a number of potential reliability limitations, including voltage, voltage stability, transient stability, and the risk of a double circuit contingency on the CBW path. The AESO has developed three conceptual options to increase generator connection capacity for the Southeast. Further details on one of the options is provided in the near-term South region plan.

Central

The geographical area west of Red Deer from Lloydminster to Brooks is called the Central East. Similar to the South region, the Central East is attractive to developers for its wind and solar potential. A number of projects are proposed in the region. The Battle River generating facility is located in Central East; while coal will not be used to generate energy in the long-term, the AESO anticipates the site could be re-developed with gas generation to leverage existing transmission infrastructure.

The Central East has bulk system constraints that limit the amount of generating capacity that can be added to the region. Transfer-out capability is provided by 912L/9L20 from Battle River to Red Deer, EATL, the Cassils/Newell – Langdon path; and several 138 kV and 144 kV lines. The CETO project, a double-circuit 240 kV transmission line between Battle River and Red Deer, is designed to mitigate future transfer-out constraints and facilitate generation developments.

Using a deterministic approach, the AESO estimated there is between 250 MW and 1000 MW of existing transfer-out capability in Central East and Southeast before the constraint on 912L/9L20 manifests, depending on where generating projects located, and subject to a specific set of assumptions about the continued existence and behavior of dispatchable generators. The CETO project will add 700 MW to 900 MW of incremental capability and when the anticipated congestion exceeds the threshold established in the NID, the AESO will direct the facility owners to begin constructing CETO.[11]

Northwest

Existing constraints in the Northwest region relate to flow into the Northwest, specifically in the 138 kV paths between Bickerdike – Little Smoky and Little Smoky – Grande Prairie. The 138/144 kV system could benefit from incremental generation development to help reduce constraints on inflow. However, accommodating large generating projects in the area can be challenging as the 138/144 kV system has limited thermal capacity to accommodate additional flow if the generation is not ideally located. Given the constraints in the Northwest are primarily driven by inflow conditions, the 240 kV network is capable of accommodating a significant amount of generation.

Northeast

Industry in the Northeast uses cogeneration to produce energy partly for its own uses, and partly to contribute to the energy market. The AESO anticipates the region will be a net producer of energy in the future, and the need will exist to transfer energy out of the region.

The Fort McMurray West transmission line, energized in 2019,[12] added substantial transfer-out capacity to the Northeast. On the other hand, the anticipated co-generation development at Suncor is expected in the near term. Transmission limitations that manifest when the co-generation capacity is added will be managed with a generation shedding RAS, allowing transmission build to be deferred. When the co-generation capacity is added, approximately 400 MW of incremental transfer-out capability will still be available for net generator additions before additional transmission development may be required.

When required, the AESO's current plan for increasing bulk transmission capacity to the Northeast is the Fort McMurray East transmission line, which will add more than 1,000 MW of incremental transfer-out capability.

Edmonton

The Wabamun Lake area west of Edmonton is a generating centre, with the majority of Alberta's baseload coal generating capacity located there. The coal generators in the region are anticipated to be retired or re-powered using natural gas and the existing system is designed to accommodate a relatively large amount of generating capacity. The Sundance, Genesee, and Keephills sites can each accommodate total generating capacity near to 2,000 MW (including new, existing, and re-powered generation). The capacity available for new generation depends on the disposition of existing assets by their owners.

Some limited transmission development may be required to connect generation in the Edmonton region. Depending on how and where generators connect, 500/240 kV transformation capacity, shared between dispatchable generators in the region and HVDC transmission, may become a constraint. As indicated in the previous LTP, the AESO has a plan to add capacity by connecting Sundance to the 500 kV system if needed. This plan is flexible and is contingent on both, the total capacity and location of new baseload generators, in the Edmonton region.

[11] https://www.aeso.ca/grid/projects/central-east-transfer-out-transmission-development/

[12] https://www.aeso.ca/grid/competitive-process/fort-mcmurray-west-500-kv-transmission-project/

Distributed Energy Resources

DERs are small generators that connect to the distribution system. The system has over 7,000 solar DERs and approximately 200 wind, gas, and other DERs. The aggregate capacity is approximately 240 MW, of which 110 MW is solar (as of summer 2021).

Distributed generators use bulk transmission capacity in the same way as an equal incremental capacity of transmission-connected generation in a nearby location. For example, an aggregate amount of 50 MW rooftop solar distributed throughout the city of Lethbridge would affect the 240 kV network in the same way as a 50 MW solar farm with a direct connection to the North Lethbridge substation.

The key difference between DER and transmission-connected generation is that DERs are co-located with load and tend to reduce the utilization of local 138 kV (or 144 kV, or 72 kV) networks in urban areas that are net consumers of energy.

When developing the 2022 LTP, the AESO forecasted net load. An offset to net demand produced by DERs was included throughout the system. The aggregate capacity of DERs is forecasted to increase and become an increasingly important part of the supply mix. The DER offset was most impactful in urban areas, especially when the Clean Tech scenario was considered. DERs are anticipated to moderate the gross load increases that will originate from population growth and increasing electric vehicle use. Consequently, the needs for load-serving upgrades in urban areas including Edmonton and Calgary will occur later than they otherwise would.

Conversely, DERs in the south and central east contribute to advancing the need for bulk system generation projects such as CETO and CRPC, because those projects are located in (weather-dependent) net-producing regions with outflow constraints.

Integration of Inverter Based Resources

With the increasing prevalence of inverter-based resources (IBRs) such as solar and wind and the retirement of synchronous machines, power systems will be faced with declining levels of inertia. Inertia refers to the kinetic energy stored in synchronously rotating mass. Inertia response provides an important contribution to reliability in the initial moments following a loss of supply or demand: inertia impacts the rate of change of frequency (RoCoF). In response to a sudden loss of supply, kinetic energy is automatically extracted from the synchronously rotating mass, causing the rotating mass to slow down helping to keep the frequency from declining as quickly. A lower level of system inertia holds less kinetic energy, which means a sudden loss of supply will pull the frequency down faster compared to a higher inertia level. The AESO will continue to monitor the system inertia going forward and will take necessary steps if there is a need to do so.

A smaller system inertia will result in a larger RoCoF which can:

- Reduce the time available for the primary frequency response (PFR) to arrest a frequency excursion. This results in the need for faster and/or larger mitigations to maintain acceptable frequency thresholds. If the RoCoF becomes too large, there is the threat that frequency thresholds cannot be maintained.
- Jeopardize the stability of the system as protection relays may trip equipment in response to the RoCoF.

Primary Frequency Response (PFR) is what the system does in response to a frequency deviation.

PFR includes:

- Generator response: a change in real power production proportional to a change in system frequency (droop controller).
- Load response: a change in real power consumption from frequency dependent loads proportional to a change in system frequency.
- Fast frequency response: an increase or decrease in real power provided to or taken from the interconnected eletcric system in response to a change in system frequency.

PFR provides an important contribution to reliability following the loss of supply or demand: PFR compensates for the power imbalance to arrest and stabilize the frequency excursion. In response to a sudden loss of supply, the PFR will work to replace the lost supply (generation will increase, load will decrease, and fast frequency response may operate). With adequate PFR, the frequency can be arrested and stabilized without having to trip customers in an under frequency event.

With the increasing penetration of renewable energy resources and retirement of traditional resources, the power system will be faced with declining generator response.

To maintain adequate levels of PFR, the following options are available:

- Improve the generator response,
- Increase the volumes for fast frequency response, and/or
- Introduce additional mitigations to supplement PFR

Another reliability consideration with the increasing penetration of IBRs is their operation during low short circuit levels (SCL). Renewable energy resources such as wind (types 3 and 4) and solar or other resources, such as a battery energy storage systems, use inverters to interface with the grid and are known as IBRs. An IBR contributes a much lower level of short circuit current compared to a synchronous generator and with the increasing penetration of renewable energy resources and retirements of synchronous machines, (e.g., coal units) power systems will be faced with a declining trend in SCLs. As the system becomes weakened, the ability of IBRs to provide expected real and reactive power is impacted potentially leading to issues including voltage instability.

SCLs are an indicator of the amount of fault current that flows on the system during a disturbance which is a reflection of how strong the grid is. These disturbances can be caused by several factors including adverse weather conditions and equipment failure. Typically, a minimum SCL is required to operate the power system in a stable and reliable manner. The functions provided by the SCL include the ability to regulate the transmission system voltage and the ability to detect and isolate faults in a cost-effective manner. The AESO will continue to monitor the SCLs on the system and propose appropriate solutions should this becomes a concern to system reliability.

The AESO will include a detailed discussion about the requirements mentioned in this section in a Flexibility report scheduled to be published later in 2022.

Energy Storage

Energy Storage penetration levels are rising in Alberta and at the end of 2021, there were about 60 MW of energy storage connected to the AIES. Currently there are 18 energy storage projects with more than 2,500 MW in the AESO connection project list.

Energy Storage in Electricity Markets

Energy storage, due to its unique attribute of storing energy by using electricity as an input and discharging it at a later time, can participate in electricity markets and provide value through energy arbitrage, firming of renewable resources output, peak shaving or peak shifting, defer transmission build, and provide grid reliability services such as operating reserves and fast frequency response. The AESO will continue to engage stakeholders including market participants as energy storage evolves in the province.

The AESO's *Energy Storage Roadmap*[13], released in August 2019, sets out the AESO's short and long-term plans to facilitate the effective integration of energy storage in the province. In 2020, the AESO provided information documents (IDs) to provide clarification to energy storage market participants regarding participation in electricity and ancillary service markets under the current framework of legislation and ISO Rules.

In 2021, the AESO completed a two-year long engagement with the industry under the Energy Storage Industry Learning Forum (ESILF) collaborative.[14] The objective of the collaborative was for members to provide expertise and key learnings to the AESO on targeted matters relating to the integration of energy storage in Alberta. In 2021, the AESO also launched a pilot project for the procurement of fast frequency response (FFR) from energy storage.[15]

Apart from tool and system modifications, at the time of publication, the AESO is working on amending applicable ISO rules and information documents to incorporate energy storage. The AESO expects to file these revised ISO rules before the AUC in 2022.

Use of Energy Storage as a Planning Alternative

From a transmission system planning perspective, the AESO will consider all appropriate alternatives to address issues identified as part of the AESO's planning process, including the potential use of energy storage, and will recommend the preferred alternative based on technical, economic and environmental/land use considerations. For future material system NIDs, the AESO will engage stakeholders by sharing information about screening alternatives considered including the potential use of energy storage as a solution, if appropriate.

[13] https://www.aeso.ca/assets/Uploads/Energy-Storage-Roadmap-Report.pdf

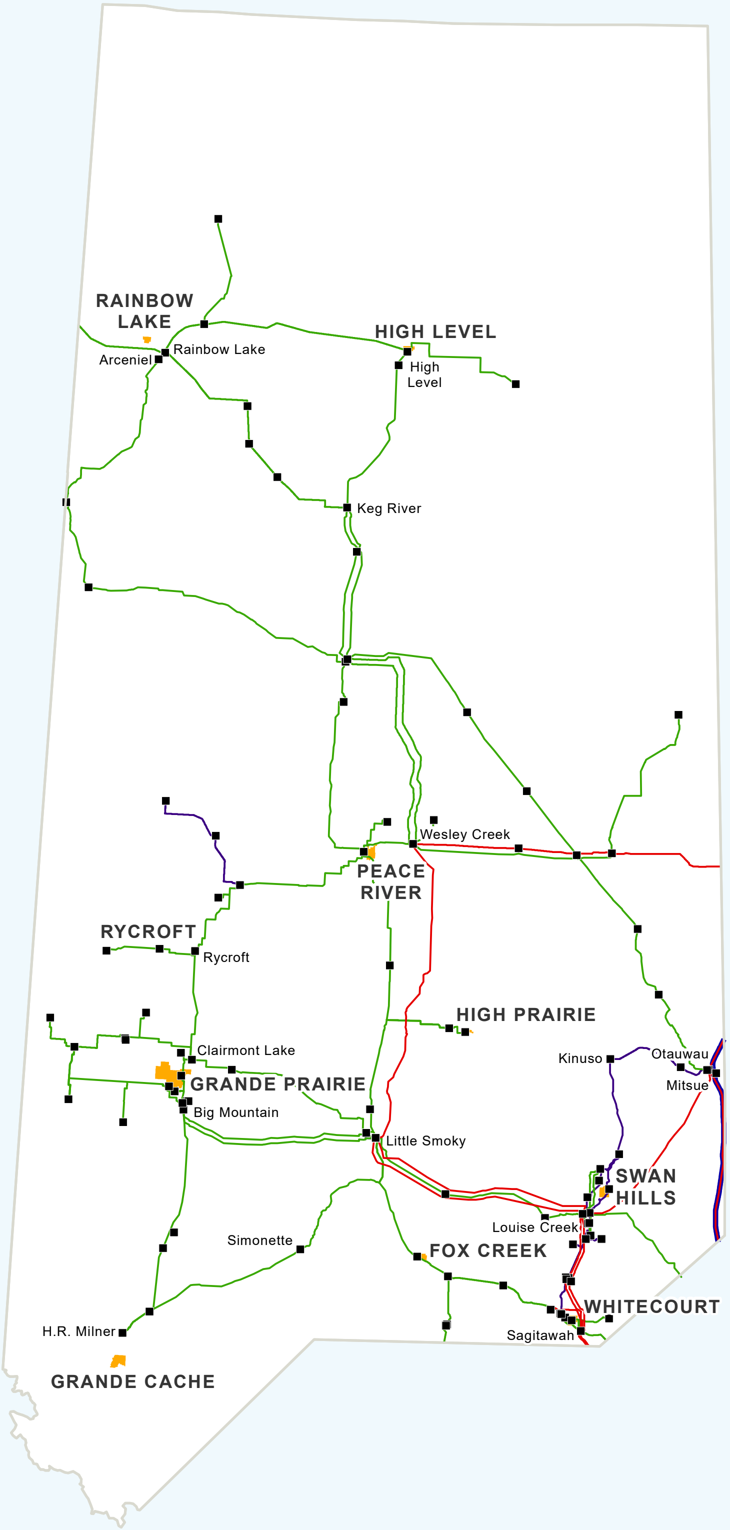
[14] https://www.aeso.ca/grid/grid-related-initiatives/energy-storage/energy-storage-industry-learnings-forum/

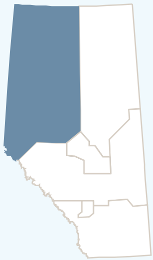
[15] https://www.aeso.ca/market/ancillary-services/fast-frequency-response/

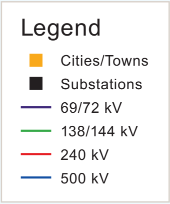
6.0 Regional Transmission Plans for the Near-term Horizon

NORTHWEST PLANNING REGION

Existing Transmission System







View Single Line Diagrams (SLDs): ***www.aeso.ca/grid/LTP***

Northwest Planning Region

Overview and Forecast

The Northwest Planning Region covers approximately one third of Alberta's land area and has five per cent of the population. The largest city is Grande Prairie, with a population near 100,000.

The Northwest has approximately 11 per cent of Alberta's load. Electricity use is mostly industrial. The region also has residential, commercial, and agricultural loads. Load growth over the past 10 years has an average annual winter peak load growth rate of one per cent. The Reference Case assumes continued load growth at a rate of 0.42 per cent per year to 2041.

The Northwest Planning Region currently has 1,295 MW of generation capacity. Approximately two thirds of that capacity is gas-fired. Most of the gas generators are simple cycle units. Some biomass capacity also exists. The net capacity of gas-fired and biomass generation has increased by 297 MW in the past 10 years. Battery storage of 20 MW has been added.

A variety of generation resources have development potential in the region. Gas-fired generation is the main expected source. The forecast anticipates 200 MW of simple-cycle generation added in the long term.

Table 3: Northwest Planning Region Load and Generation Capacity Forecast

Calendar Year	2020 (MW)	2026 (MW)
Region Peak Load	1,232	1,205
Coal-fired / Coal-to-gas	208	208
Cogeneration	162	162
Combined-cycle	73	73
Simple-cycle	650	683
Hydroelectric	0	0
Wind	0	0
Solar*	0	0
Other	182	182
Storage	20	20
Total Generation Capacity	1,295	1,328

**This figure does not include rooftop solar, which is accounted for in the load forecast*

Existing Transmission System

The Northwest Planning Region is primarily served by a 240 kV network that transfers power into the region from the Wabamun Lake area and the Northeast. Local load is served by a 144 kV network connected to 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 72 kV transmission.

Transmission Project Status

- The **Rycroft** project NID Application for reactive power support was filed with the AUC in December 2017 and approved in May 2019.[16] The targeted in-service date for this project is 2023.

Transmission Plans

Overloads on the 138/144 kV transmission lines in the Fox Creek area between Bickerdike and Little Smoky may occur under system normal or outage conditions. The overloads depend on load and generation dispatch. The most important factor is the amount of load in the Fox Creek area. Generation at Bickerdike is also a factor. A new 240 kV transmission line may eventually be needed to relieve loading on the 144 kV system as indicated in previous LTPs. However, line rating increases are planned in the near term to optimize the use of the existing transmission system and defer the need for a new 240 kV transmission line.

Each transformer at the Little Smoky substation may overload if the other transformer is out of service. The addition of a third transformer or replacement of both existing transformers are mitigation options.

Overloads of the transmission line between Little Smoky and Clairmont Lake were observed in contingency conditions with peak load and low generation in Grande Prairie. A new transmission line serving Grande Prairie is planned to mitigate this issue.

Low voltages were observed in the Grande Prairie/Grande Cache and High Prairie areas for specific contingencies. Voltage support (such as capacitor banks) may become necessary.

Several generation projects have proposed connections in the Northwest. The projects are not included in the Reference Case, but the AESO has considered them in sensitivity studies or connection studies. System performance in the area will be improved with the addition of some generation, but too much generation could trigger additional transmission system reinforcements.

Table 4: Summary Planned Development

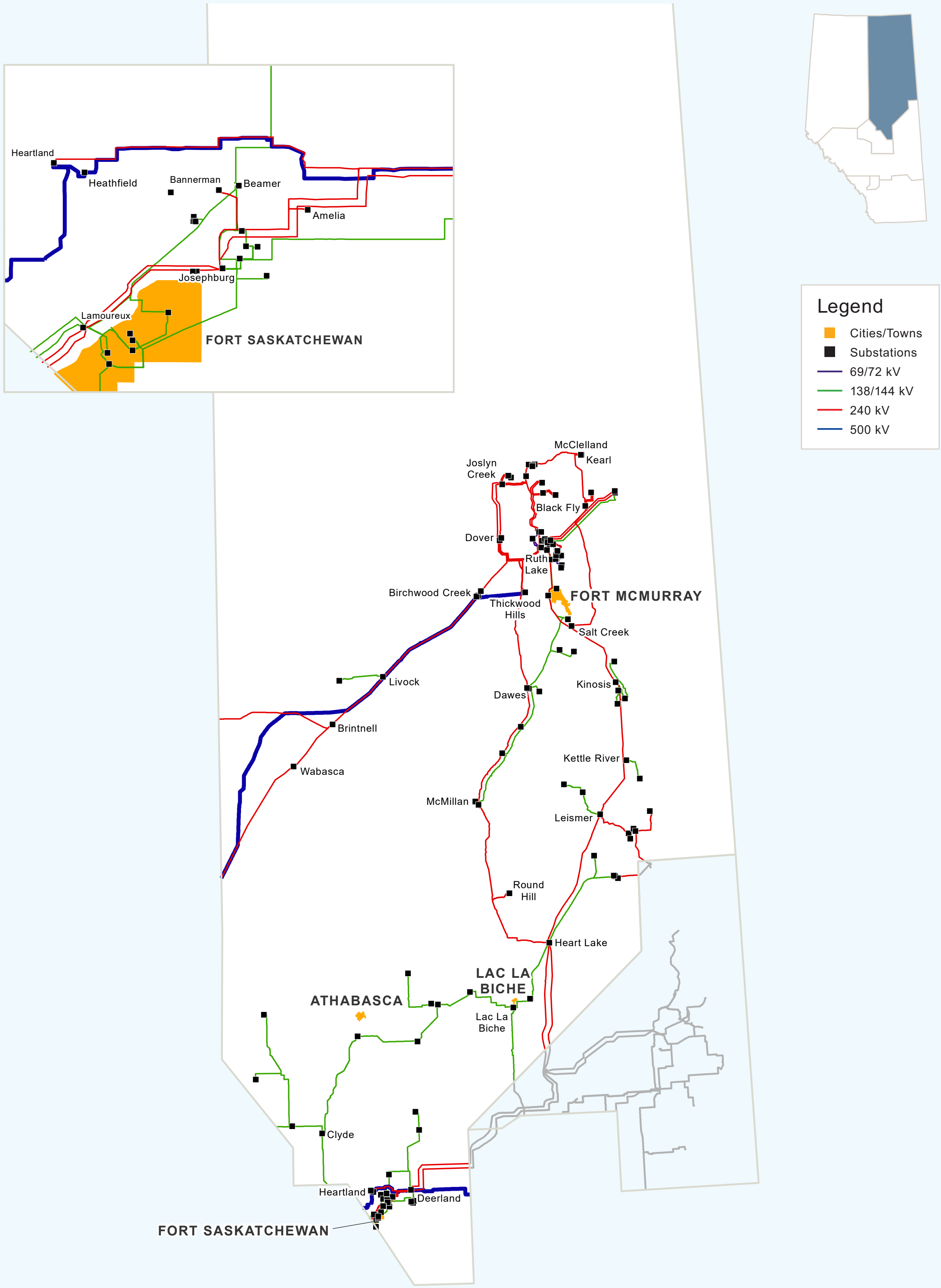
The following developments are planned:

Development	Description	Driver	Deferrable
Grande Prairie Area	Build a new substation on 9L11 Build a single-circuit transmission line from the new substation to Clairmont Lake 811S	Load in Grande Prairie/ Grande Cache	Yes
Grande Cache voltage support	Add voltage support at H.R. Milner 740S and/or Simonette 733S	Load in Grande Cache	Yes
Little Smoky transformation	Replace the existing 240/144 kV transformers with higher-capacity units or add a third transformer at Little Smoky 813S	Load in Grande Prairie/ Grande Cache	Yes
High Prairie voltage support	Add a capacitor bank at Kinuso 727S or a transformer at Otauwau 729S	Load in High Prairie	Yes

[16] https://www.aeso.ca/grid/projects/voltage-support-at-rycroft-730s

NORTHEAST PLANNING REGION

Existing Transmission System



View SLDs: ***www.aeso.ca/grid/LTP***

Northeast Planning Region

Overview and Forecast

The Northeast Planning Region is sparsely populated, with approximately three per cent of Alberta's population. Residential and commercial load are commensurately small. Most residents are located in the Fort McMurray area of the Regional Municipality of Wood Buffalo. The economy in the region is driven by the oil sands industry and growth is linked to future oil sands projects.

Despite its low population, the Northeast Planning Region has about 30 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 six 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 0.38 per cent to 2041.

The region currently has 3,638 MW of generation, mostly in the form of cogeneration. Some biomass generation also exists. The Northeast had more generation capacity growth in the past 10 years than any other region. Most generation development was cogeneration related to the petroleum industry.

The forecast includes over 1,500 MW of gas-fired cogeneration additions in the long term. A small amount of simple-cycle generation is also anticipated.

Table 5: Northeast Planning Region Load and Generation Capacity Forecast

Calendar Year	2020 (MW)	2026 (MW)
Region Peak Load	3,264	3,558
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 figure does not include rooftop solar, which is accounted for in the load forecast*

Existing Transmission System

The Northeast has a 240 kV network that serves large industrial operations in the Fort McMurray and Fort Saskatchewan areas and a high capacity 500 kV connection to the Edmonton region. Some local areas are served by 138/144 kV networks.

Transmission Project Status

- **807L (Beamer–Shell) 138 kV line Rebuild**–the project was approved by the AUC in 2017. Further analysis showed that it is possible to optimize the existing system by using operational measures to reliably defer the rebuild. The AESO continues to monitor thermal loading in the area and will direct AltaLink to begin construction for the approved facilities when it determines that operational measures will not sufficiently manage the overload and constraints in the area.

Transmission Plans

Low voltages may occur at the Kearl substation in contingency conditions involving high load and generator outages. A capacitor bank at McClelland is a potential mitigation.

A large cogeneration project is anticipated in the region. When the project is completed, high net generation output in the region combined with transmission contingencies may lead to overloads of the 240 kV tie with the Northwest. The phase shifting transformer (PST) at Livock is a useful mitigation. A remedial action scheme (RAS) that sheds generation in response to unplanned transmission outages is planned to mitigate the problem in situations where the PST alone is insufficient.

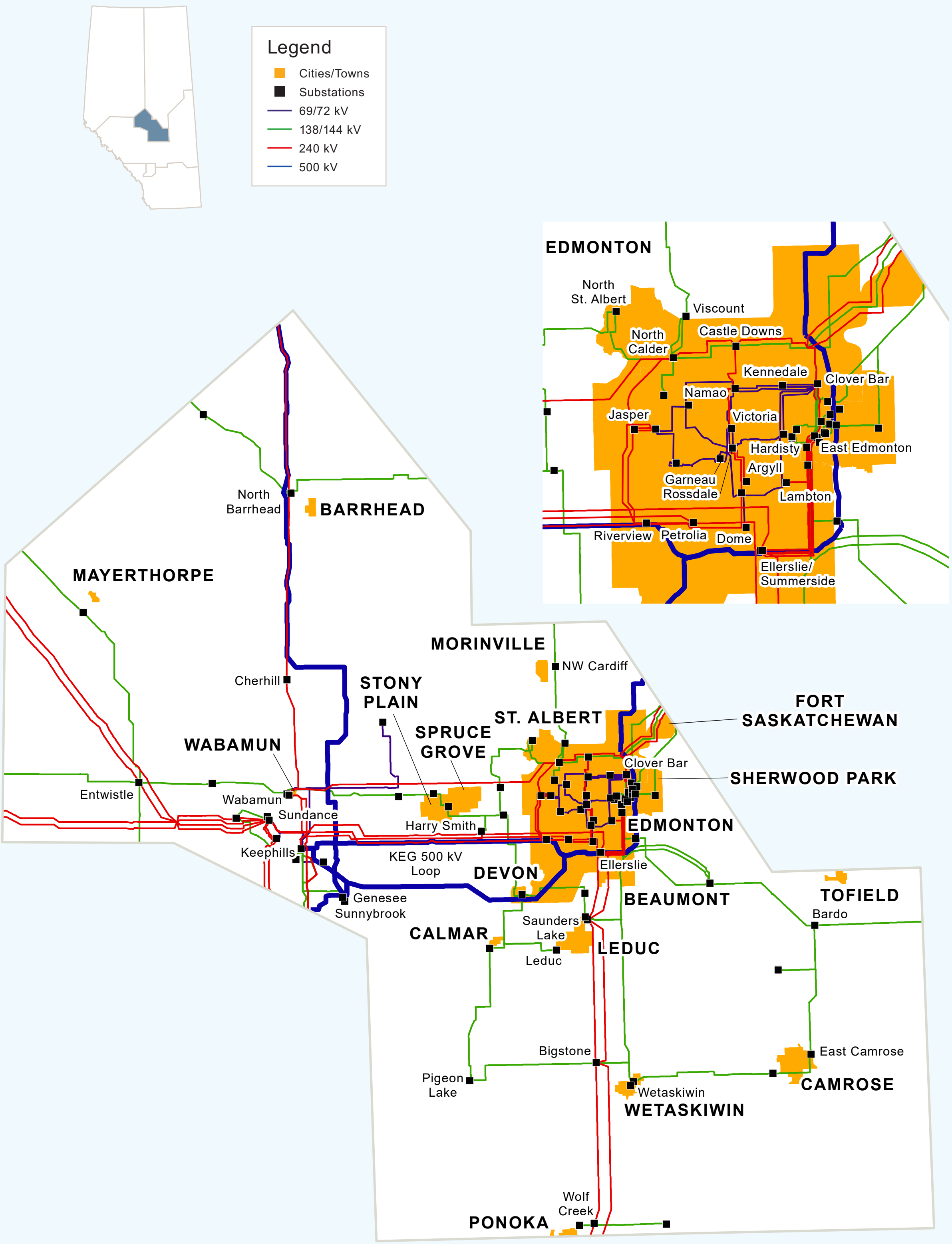
Table 6: Summary of Planned Development

The following developments are planned:

Development	Description	Driver	Deferrable
McClelland voltage support	Capacitor bank at McClelland 957S	Load in the McClelland area	Yes

EDMONTON PLANNING REGION

Existing Transmission System



View SLDs: www.aeso.ca/grid/LTP

Edmonton Planning Region

Overview and Forecast

The Edmonton Planning Region covers the City of Edmonton, St. Albert, Sherwood Park, Spruce Grove, Leduc and the Wabamun Lake area. Approximately 34 per cent of Alberta's population lives in the region. The region has a significant amount of dispatchable coal and gas generation.

The Edmonton region has 16 per cent of Alberta's load. In the past 10 years, the average annual load growth rate was one per cent for the summer peak and 0.4 per cent for the winter peak. The region has residential, commercial, oil refining, manufacturing and pipeline load.

The forecasted annual growth rate of winter peak load is 0.3 per cent. The bulk of growth is expected in the City of Edmonton, primarily comprising residential, commercial and industrial load. The adoption of EVs is anticipated to contribute to residential load growth while rooftop solar panels and energy efficiency improvements are expected to offset some of that load growth.

The Edmonton Planning Region has approximately 3,500 MW of generating capacity, provided mainly by coal and gas units. Recently, some coal units have been retired, and facility owners have made other coal units capable of running on natural gas or announced plans to do so.

Coal-fired generation is expected to convert to natural gas. In the long term, approximately 1,500 MW of generating capacity from new combined-cycle facilities is anticipated to compensate partially for the retirement of coal and converted gas units which will lead to a net reduction in generating capacity in the long term.

Table 7: Edmonton Planning Region Load and Generation Capacity Forecast

Calendar Year	2020 (MW)	2026 (MW)
Region Peak Load	2,183	2,138
Coal-fired / Coal-to-gas	3,114	3,114
Cogeneration	92	92
Combined-cycle	0	0
Simple-cycle	250	270
Hydroelectric	0	0
Wind	0	0
Solar*	0	10
Storage	0	5
Total Generation Capacity	3,456	3,491

**This figure does not include rooftop solar, which is accounted for in the load forecast*

Existing Transmission System

Edmonton is the central hub for the provincial grid, connecting the north and south with transmission lines operating at 500 kV and 240 kV. These bulk transmission lines transfer power from the region to the rest of the province.

A 500 kV loop brings power from coal/gas generators in the Wabamun Lake area to the City of Edmonton. The loop extends to the Heartland substation in the Northeast. A 72 kV system in Edmonton is dedicated to serving load within the city. A 138 kV network serves load in the east Edmonton industrial area and outside the city.

Transmission Plans

The 72 kV network in Edmonton has several aging oil-filled cables and is becoming constrained due to growing load. The planning studies anticipate the capacity to serve load at Kennedale, Hardisty, and Garneau will become insufficient in contingency conditions. A long-term solution is needed to provide reliable supply.

The AESO is currently working with EPCOR to determine the preferred solution to provide reliable long-term supply for the City of Edmonton. The City of Edmonton Development described below is one potential solution. The schedule for implementation of the City of Edmonton project depends on the rate of load growth within the city.

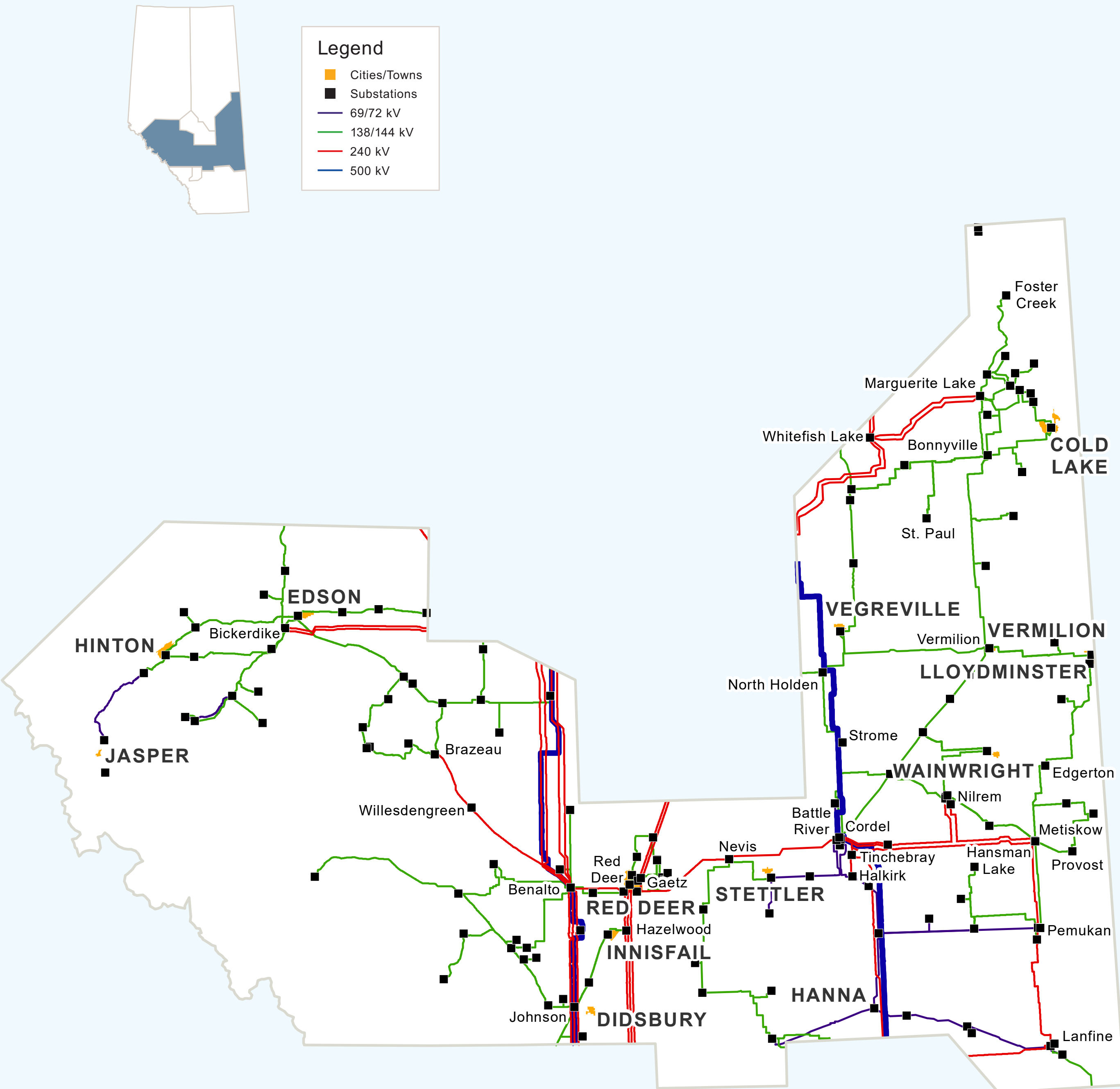
Overloads were observed on several transmission lines outside the city. These overloads can be addressed through line rating increases and the AESO will work with the TFO to determine the optimized solution.

Table 8: Summary of Planned Development

Development	Description	Driver
North Calder to N.W. Cardiff	Increase the rating for 898L from North Calder 37S to Viscount 92S Increase the rating for 792L from Viscount 92S to N.W. Cardiff 191S	Load in north Edmonton, Athabasca, and Northwest area
The City of Edmonton	Replace the Garneau – Rossdale cables, increasing their capacity Create a new 240/72 kV substation called East Terminal Cut into 915L (Clover Bar – East Edmonton 38S) and bring two 240 kV circuits into East Terminal Decommission the Kennedale substation and cables Redistribute load from Kennedale, Namao, and Hardisty among East Terminal, Namao, and Hardisty, with the bulk of Kennedale load going to East Terminal. Discontinue use of the Hardisty – Clover Bar cables and supply Hardisty from Lambton 803S Add a new 72 kV circuit from East Industrial to Hardisty Add a new 240 kV circuit from Victoria 511S to East Terminal Add two 72 kV circuits from East Terminal to Namao Join the Namao terminals of cables 72NW15 and 72NV21, bypassing Namao	Load in the City of Edmonton
Wetaskiwin Area	Increase the rating for 174L from Bardo 197S to North Holden 395S	Load in Edmonton region and generation in CE

CENTRAL PLANNING REGION

Existing Transmission System



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Central Planning Region

Overview and Forecast

The Central Planning Region spans the province east to west and extends north to south between Edmonton and Calgary. Red Deer and Lloydminster are its major population centres. The region has about 11 per cent of Alberta's population. Considerable manufacturing activity occurs in the region. Oil and gas development has occurred in the Cold Lake area. Pipeline loads are present in the region, particularly in the east.

The Central region currently represents 19 per cent of Alberta's load. Over the past 10 years, winter peak load has grown by an average annual rate of 1.5 per cent. The Reference Case models an annual winter peak load growth rate of 1.1 per cent. Load growth drivers include industrial and oil sands growth, pipelines, and increasing population.

The Central Planning Region currently has 2,500 MW of generation capacity comprising cogeneration, coal-to-gas, hydro, and wind. 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 600 MW are primarily wind and co-generation. Coal-fired generation in the region has been retired or converted to natural gas.

The forecast for the Central Planning Region anticipates added gas-fired and renewable generation. Approximately 900 MW of new combined-cycle gas generation and 600 MW of new renewable generation was assumed.

Table 9: Central Planning Region Load and Generation Capacity Forecast

Calendar Year	2020 (MW)	2026 (MW)
Region Peak Load	2,191	2,311
Coal-fired / Coal-to-gas	540	540
Cogeneration	1,150	1,240
Combined-cycle	0	900
Simple-cycle	18	51
Hydroelectric	485	485
Wind	261	709
Solar*	22	67
Other	50	50
Storage	0	5
Total Generation Capacity	2,526	4,047

**This figure does not include rooftop solar, which is accounted for in the load forecast*

Existing Transmission System

Six 240 kV transmission lines pass from Edmonton to Calgary through the Central region. Several intermediate 240 kV substations provide bulk system access for the region. The two north-to-south HVDC lines also pass through the Central region.

The Hanna area is served by a 240 kV loop, which also provides transmission access for renewable generators. The 240 kV network extends west to the Brazeau hydro station and to Bickerdike in the northwest, where the connection of the 900 MW Cascade combined cycle generator is expected. The Cold Lake area is served by a double-circuit 240 kV line and a local 144 kV network supporting oil sands and industrial operations.

Local area load is supplied by a looped 138 kV and 144 kV network that extends throughout the Central region.

Transmission Project Status

- **PENV**–the NID Application for PENV was approved by the AUC in April 2019. However, the AESO anticipates the existing system can accommodate additional renewables generation before PENV is needed. The AESO will work with TFOs to determine the next steps for FA of the Nilrem to Drury line.
- **CETO**–the NID Application for CETO was approved by the AUC in August 2021. The AESO is monitoring generation development in the region and initiating the re-affirmation study process to confirm the timing of construction before directing the TFOs to initiate construction.

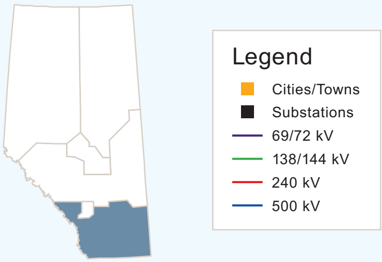
Transmission Plans

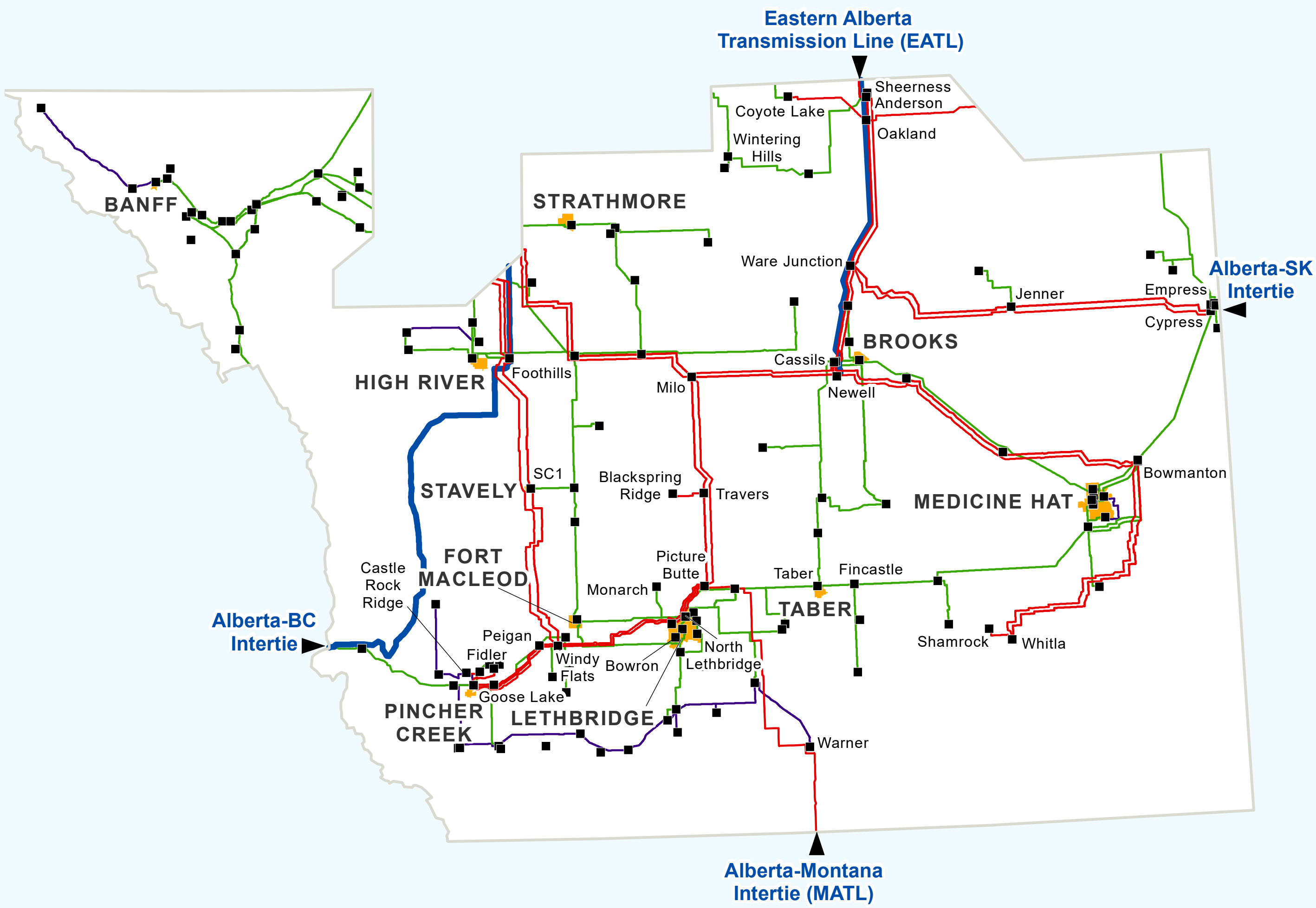
The near-term need of the region is expected to be met by PENV and CETO projects.

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 as the AESO is re-assessing the need for Phase 2.

SOUTH PLANNING REGION

Existing Transmission System





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South Planning Region

Overview and Forecast

The South Planning Region spans the province east to west and extends from the latitude of Calgary to the border with the USA. Its population centres include Lethbridge, High River, Brooks, and Medicine Hat. Approximately 12 per cent of Alberta's population lives in the region. Electrical load is generally summer peaking because of seasonal uses including agriculture and air conditioning.

The South Planning Region has approximately 11 per cent of AIL. Electricity is used for agricultural and industrial purposes - including pipelines, manufacturing, and natural gas processing. Over the past 10 years, the summer peak load has grown by an average annual rate of one per cent. Under the Reference Case, the region's peak load is expected to grow at a rate of 0.42 per cent annually until 2041.

The South currently has 3,405 MW of generation capacity. Wind generation contributes 1,520 MW of capacity; coal-fired and coal-to-gas generators contribute 800 MW. 400 MW of coal-fired generation in the region has retired and been converted to natural gas. Other generators are a mix of hydro, solar, and cogeneration. The region has net growth of 844 MW in generating capacity over the last 10 years.

The generation forecast for the South Planning Region anticipates growth in renewable generation and a decrease in coal-fired generation. The 20-year forecast anticipates new generation including approximately 2,500 MW of wind and 1,100 MW of solar.

Table 10: South Planning Region Load and Generation Capacity Forecast

Calendar Year	2020 (MW)	2026 (MW)
Region Peak Load	1,378	1,576
Coal-fired / Coal-to-gas	800	800
Cogeneration	100	100
Combined-cycle	417	417
Simple-cycle	64	141
Hydroelectric	409	409
Wind	1,520	3,295
Solar*	85	955
Storage	10	15
Total Generation Capacity	3,405	6,132

**This figure does not include rooftop solar, which is accounted for in 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 that connects the main load centers with regional generation sources. The region has a small number of 69 kV facilities, including those south of Lethbridge and within Banff National Park.

Existing 240 kV lines extend from the Calgary area to Brooks and Lethbridge. A 240 kV network delivers power from the Sheerness and Battle River generators to the Brooks area. Several 240 kV circuits were added to the region to facilitate the connection of renewable generators via the SATR project. In 2015, the double-circuit 240 kV line from Windy Flats (near Fort Macleod) to Foothills and the double-circuit 240 kV line from Whitla to Brooks via Medicine Hat were energized. EATL, which terminates near Brooks, can transfer renewable energy to the north when production exceeds regional demand.

Transmission Project Status

- **CRPC Transmission Development**–the 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. The AESO plans to file a NID approximately four years before forecasted congestion occurs to enable enough time to obtain regulatory approvals and complete construction.

Transmission Plans

An upgrade is needed for serving load in the Lethbridge area. The 138 kV network serving load in and around the city is anticipated to be overloaded in contingency conditions. The plan for mitigating this issue is to create a new 240 kV source west of the city and integrate it with the 138 kV network via the Bowron substation.

Overloads are anticipated on the 138 kV network between Taber and Medicine Hat due to generator interconnections. The plan for mitigating the overloads is to increase the capacity of the existing transmission lines. A power flow control device such as an SSSC may be used in addition to ratings increases. Cost optimization will determine whether flow control is used. Similarly, overloading is anticipated on the 138 kV transmission line from Chestermere to Strathmore, and the planned mitigation is to increase the rating of that line.

Overloads are anticipated on the 138 kV network west of Coyote Lake due to generator interconnections. The plan for mitigating the overloads is to build a new 138 kV transmission line between Coyote Lake and Wintering Hills.

The Southeast

The AESO has seen strong interest in connecting renewable generators in the southeast sub-region.[17] The aggregate capacity of proposed projects exceeds the capacity of the existing transmission network. The forecast anticipates a considerable increase in net generating capacity, but the aggregate capacity of customer projects significantly exceeds the forecast. The AESO is developing a Southeast transmission plan that will enable renewable generators to connect in the region that is commensurate with generation development interest. The plan will prevent thermal overloading in contingency conditions, and may also address the risks of loss of generation for extreme events such as loss of double circuit transmission lines.

The three conceptual solutions developed for the Southeast are:

- New 240 kV double circuit line from Bowmanton to Cypress.
- New 240 kV double circuit line from Whitla to Newell.
- New 240 kV double circuit line from Whitla to Picture Butte and new 240 kV single circuit line from Picture Butte to Milo.

The AESO is performing detailed planning studies including a congestion assessment to refine the southeast plan. While there is urgency to develop a plan for the Southeast, the pace of the development is dependent on the pace of renewables generation developments in the area. The project will be a milestone-based project using an approach similar to CETO to determine when construction begins.

Intertie

Both of Alberta's alternating current (AC) interties, the Alberta–B.C. intertie and MATL, are located in the South. MATL is a merchant 230 kV tie line from Great Falls, Montana to Picture Butte (near Lethbridge). The main element of the BC tie is the 500 kV tie line from Cranbrook, BC to Langdon (near Calgary to the east). The BC tie also has two relatively low-capacity 138 kV elements.

[17] (The AESO refers to the area east of Lethbridge as the southeast; the southwest is west of Lethbridge.)

The interties play an important role in maintaining the reliable operation of the AIES. When the interties are connected, the Alberta grid is synchronized with the Western Interconnection, and when loss of load or generation occurs in Alberta, the net imbalance manifests as flow on the interties.

The AESO has a plan to increase the power transfer capability of the Alberta–B.C. intertie. The plan includes upgrading the 500 kV transformer that connects the main BC tie to the system and adding series compensation to increase the stable transfer capability of the tie line. While the AESO does not plan to implement the CRPC project for the sole purpose of improving the intertie, the project would increase intertie capability to some extent upon completion.

Whereas the interties help maintain frequency stability when they are connected, intertie contingencies can cause significant frequency excursions. Currently the Montana tie must be opened when the Alberta–B.C. intertie trips, and loss of both ties creates a frequency island. The AESO uses contracted load shedding to maintain a stable frequency when islanding occurs. Frequency performance is becoming is becoming a growing concern, as renewable generators are increasing in prevalence and have different performance characteristics from classical generators. Therefore, the AESO is looking for opportunities to improve frequency performance and allow for islanding at higher transfer levels. Converting MATL to an HVDC link, using a back-to-back configuration, is one of the options under consideration.

Table 11: Summary of Planned Development

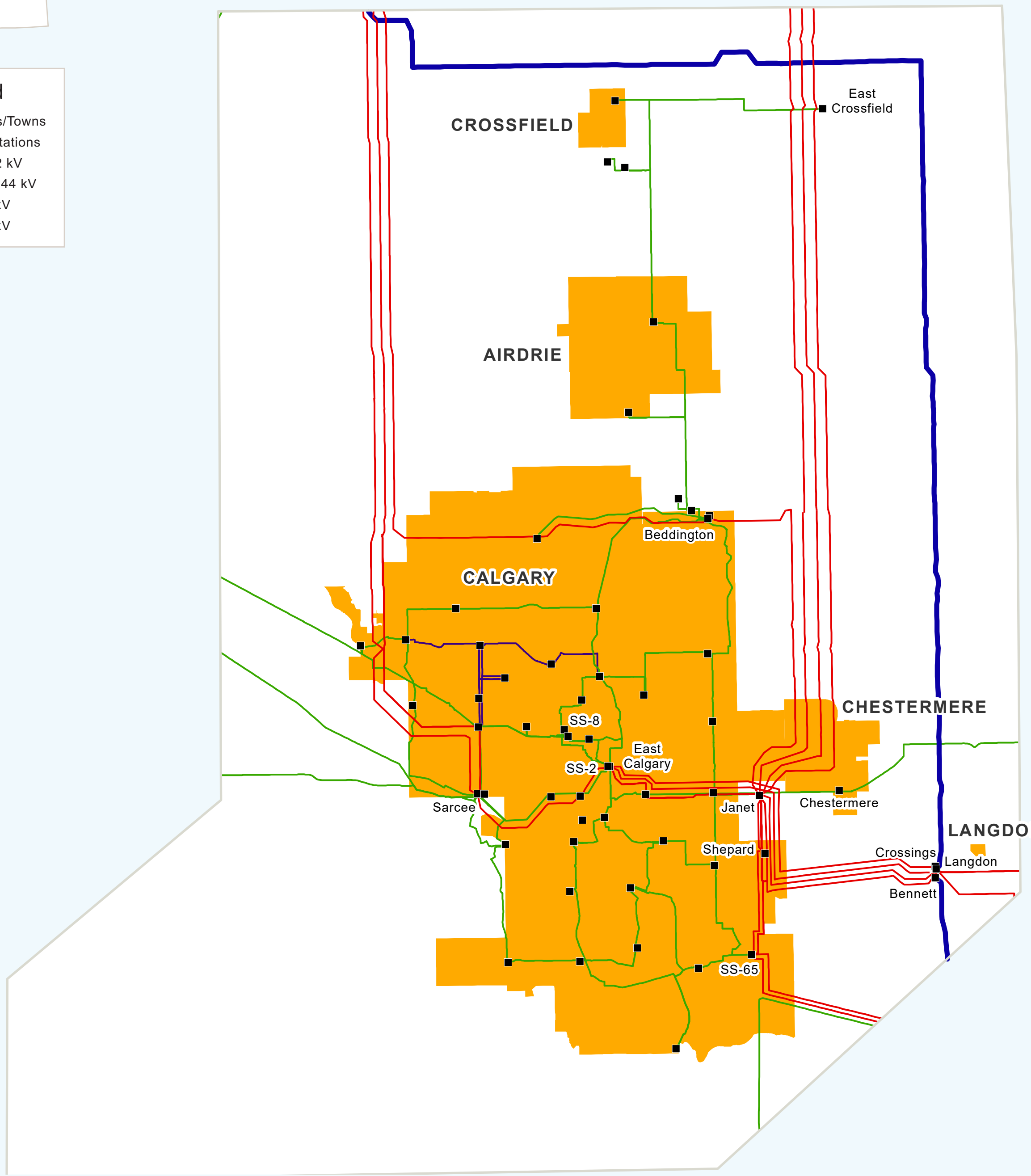
Development	Description	Driver	Deferrable
Alberta–B.C. Intertie Restoration	Upgrade the Bennett transformer Add series compensation for the 500 kV BC tie	Intertie	Yes
MATL HVDC back-to-back converter	New HVDC back-to-back converter located at or near Picture Butte substation	Intertie	Yes
Chapel Rock–Pincher Creek Area Transmission Development	Build CRPC, a 500/240 kV substation adjacent to the intertie Add a new 240 kV transmission line from Chapel Rock to a substation in the Pincher Creek area (approximately 40 km) Add voltage support (a capacitor bank and/or SVC)	Generation in SW	Yes
Lethbridge Area	Build new 240/138kV substation connected to the 240 kV transmission lines between North Lethbridge 370S and Windy Flats 138S Add a new 138kV line from the new substation to Bowron 674S Add voltage support at Monarch 492S Add a breaker in the North Lethbridge substation	Load in Lethbridge area	
Sheerness Area	Add a new 138kV circuit from Wintering Hills 804S to Coyote Lake 963S	Generation in Sheerness area	Yes
Vauxhall Area	Increase the capacity of 610L (Fincastle 336S to Taber 83S) Increase the capacity of 879L (244S Bowmanton to 879AL tap) Add flow control device if needed	Generation in Vauxhall & Medicine Hat areas	
Southeast 240 kV Transmission Reinforcement	New double circuit 240 kV line from Whitla or Bowmanton	Generation in SE	

CALGARY PLANNING REGION

Existing Transmission System

Legend

- Cities/Towns
- Substations
- 69/72 kV
- 138/144 kV
- 240 kV
- 500 kV



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Calgary Planning Region

Overview and Forecast

The Calgary Planning Region includes the City of Calgary, Airdrie, and nearby communities, and accounts for about 34 per cent of the province's total population. Electricity is used primarily for urban residential, commercial, and industrial purposes. Although Calgary has been winter-peaking in past years, it was summer-peaking in 2018 due to an unusually hot summer.

The Calgary region has 12 per cent of provincial load. Summer peak average annual load growth has been one per cent over the past 10 years while winter-peak load has decreased by 0.05 per cent. The Reference Case assumes peak load will grow at 0.26 per cent to 2041 due to population growth, associated commercial and residential demand growth, and electric vehicle use. Increased rooftop solar adoption and energy efficiency gains are anticipated to offset some of the load growth.

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

A modest increase in simple cycle gas generation is anticipated in the region.

Table 12: Calgary Planning Region Load and Generation Capacity Forecast

Calendar Year	2020 (MW)	2026 (MW)
Region Peak Load	1,724	1,651
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 figure does not include rooftop solar, which is accounted for in the load forecast*

Existing Transmission System

Calgary is a major hub in the transmission network. Four 240 kV north-to-south transmission lines and one 500 kV HVDC line (WATL) terminate in the city, which is encircled by 240 kV transmission. Load within the city is served by a meshed 138 kV network that connects to each of 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.

Calgary is connected to the South region by 240 kV double circuit lines to the Windy Flats transmission hub (near Pincher Creek) directly south of the city, and to Brooks via Milo to the southeast.

The 500 kV Alberta–B.C. intertie connects to the system at Langdon, approximately 10 kilometres east of the city.

Transmission Project Status

- The **Downtown Calgary Transmission Development** was a new 138 kV circuit connecting the ENMAX No. 2 and ENMAX No. 8 substations. The project was energized in summer 2020.

Transmission Plans

The system has a RAS that sheds load in Chestermere in the event of thermal overload or under-voltage in contingency conditions. The RAS is available, however it is not currently active. These conditions could occur if load grows quickly in Chestermere. As the system evolves and more generation connects east of Chestermere, the thermal and voltage condition is anticipated to improve. However, the AESO continues to monitor load and generation developments in the area and could propose other solutions as required.

7.0 Longer-term Plans

Longer-term Plans

The AESO's transmission planning is a continuous process, based on detailed engineering evaluations of the transmission system over a 20-year planning horizon, and is designed to be flexible in order to respond to pace uncertainties and generation requirements.

Reference Case

Northwest

The need for the Fox Creek 240 kV development depends on load in the Fox Creek area.

The need appears to be deferrable by increasing line ratings for existing transmission lines. Therefore, the AESO will continue to monitor developments in the Northwest and propose the 240 kV transmission development when it's needed.

Northeast

The longer-term plan has included the Fort McMurray East 500 kV transmission line for some time. The need for the Fort McMurray East line is driven by the development of oil sands facilities. Its purposes are to transfer excess energy out of the region when co-generation produces more electrical energy than needed for industrial processes, or to provide energy when co-generation resources are insufficient for industrial demand.

Recent history suggests industrial load and generation develop in tandem in the Northeast. Load growth is often accompanied by new co-generation. The growth rate of the Northeast is anticipated to be slower in the future than it was in the past. The AESO is using flexible dynamic solutions like remedial action schemes to defer the need for transmission. For these reasons, the AESO will monitor growth rates in the Northeast and will only initiate new development when needed, which is not anticipated within the next 10 years.

Edmonton

The City of Edmonton project will be implemented in stages over a number of years. Some parts of the project are required more urgently. Specifically, the AESO is actively preparing to seek approval in developing a long-term solution for the Kennedale area to address both thermal reliability criteria violations as well as providing a solution for oil-filled cables reaching end-of-life. Other parts of the project may be deferrable. The 240 kV connection between East Terminal and Victoria is likely to be the last stage of the project, with Hardisty and Garneau upgrades being implemented at intermediate stages depending on localized load growth, asset condition, and other factors.

Central

No major transmission projects beyond CETO and PENV are currently anticipated in the Central region.

Calgary

Calgary is well-positioned for load growth at the anticipated rate, and a major transmission development may not be needed within the planning horizon.

As additional renewable generation development occurs in regions south of Calgary, the flow pattern in the Calgary region will be affected and power transfers from Foothills to Janet will increase. While operational measures including substation reconfigurations at Sarcee 42S can are required more urgently defer the need for transmission development, a transmission project may ultimately be needed. The southeast project discussed below will determine which solution is ultimately preferred.

South

The Southeast Transmission Reinforcement is a major bulk transmission project that adds capacity for generator connections in a wide geographical area. The pace of development depends heavily on pace of renewables generation developments. The AESO will further investigate the conceptual options and identify the preferred options. Where available, the overall project may be staged, and some of the stages may be deferred using milestones and constructed later depending on the pace of generation developments.

Clean-Tech Scenario

The AESO incorporated a Clean-Tech scenario into our planning work to investigate the impacts of increased penetration of EVs and higher growth of renewable generator capacity on the transmission system, compared to the Reference Case. Distributed generation, such as rooftop solar, was also a consideration in the Clean-Tech scenario.

North

The northern regions are anticipated to have little transmission-connected renewable generation as the AESO anticipates developers will choose the south and central regions for most projects. Since the north is sparsely populated and electrical load is dominated by industry, consumer technologies are not expected to drive transmission development.

Edmonton and Calgary

The cities of Edmonton and Calgary are affected more than other regions by the increased adoption of EVs. The resulting increase in load could drive substantial transmission development in both cities. If load grows at a rate similar to the Clean-Tech forecast, transmission needs will begin to manifest within 10-to-15 year timeframe. It is premature to propose preferred solutions to these transmission needs at this time.

In Calgary the following needs are anticipated, in rough order of precedence:

- Overloading of the 138 kV path from Janet to Beddington may occur due to loss of 240 kV supply to Beddington. Operational measures to mitigate the violation could include cross tripping the 138 kV after the 240 kV contingency. Possible solutions could include the addition of another 240 kV supply line to Beddington or the creation of a new substation east of the city. The preferred development will depend in part on the development of communities in the city’s northeast.
- Overloading of the 138 kV network in Airdrie may occur due to loss of the connection to either Beddington or East Crossfield. Extension of the 138 kV network to create an additional supply node for Airdrie is a possible solution, depending on load growth in Airdrie and other changes in the area.
- Overloading of the 69 kV network in the northwest/Nose Hill area. Conductor replacement or upgrade to 138 kV are potential solutions, depending on land use impact and asset condition at the time.

In Edmonton the City of Edmonton project addresses the highest-priority needs. The following additional needs are anticipated, in rough order of precedence:

- Overloads were observed on two 138 kV lines in the East Edmonton industrial area. Transmission needs in this area are likely to depend on customer projects, and the AESO will wait for more information to become available via customer connection requests before proposing solutions.
- High renewable generation in peak load conditions may strain 500/240 kV transformation capacity in the Keephills/Ellerslie/Genesee loop. The need is related to the amount of combined cycle generation connected to the 500 kV system. An additional transformer is a potential solution.
- Overloads may occur in the 138 kV system near Spruce Grove to the west of the city due to loss of supply from North Calder. Creation of an additional 240 kV source or reinforcement of the 138 kV system are potential solutions.

Central and South

The Southeast Transmission Reinforcement and CRPC are the AESO's plans for increasing generator interconnection capability in the southeast and southwest respectively. As the Clean-Tech scenario forecasts increased additions of renewable generators, the need for these projects may occur earlier if this scenario is realized.

In the Central region, the CETO development is sufficient to facilitate the renewable generator additions modeled in the Clean Tech scenario.

Robust Oil and Gas

A Robust Oil and Gas scenario was considered to investigate how relatively high growth in the petroleum industry might affect transmission system needs.

The Fort McMurray East 500 kV line is the AESO's plan for increasing the bulk transmission capacity accessible to the oil and gas industry. Despite the higher growth rate represented in the Robust Oil and Gas Scenario, the AESO does not anticipate the Fort McMurray East line will be needed soon. However, industrial development in the Northeast is highly dynamic. The AESO is prepared to respond to changing economic conditions by advancing or deferring development of the Fort McMurray East line as needed.

In addition to contributing to the need for bulk transmission capacity, individual industrial projects can pose unique system integration challenges. Such needs will be addressed as they are discovered, through the customer connection process.

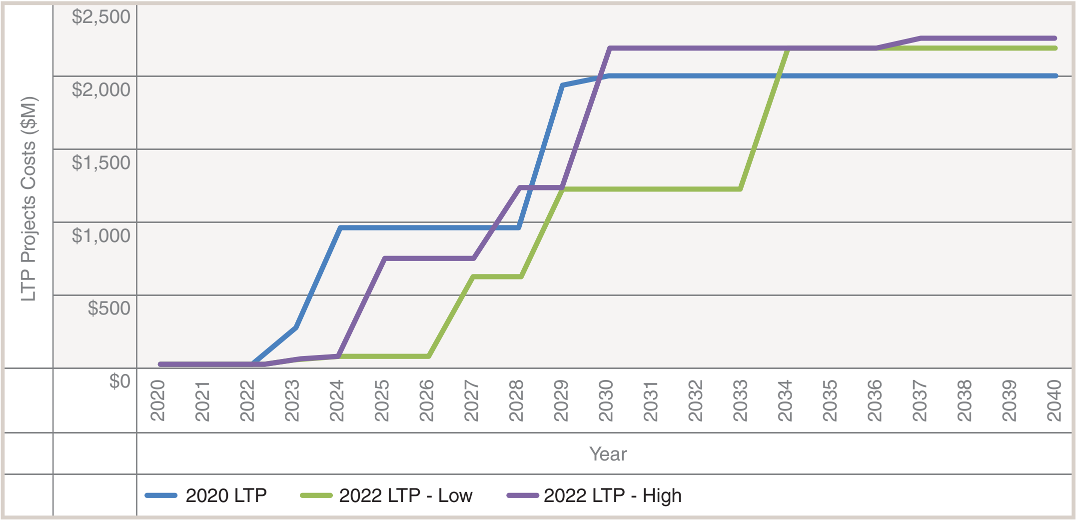
8.0 Cost Impact of the 2022 LTP

Cost Impact of the 2022 LTP

Identified projects still need to undergo required needs analysis; the AESO is committed to monitoring developments and updating pace and timing as deemed necessary.

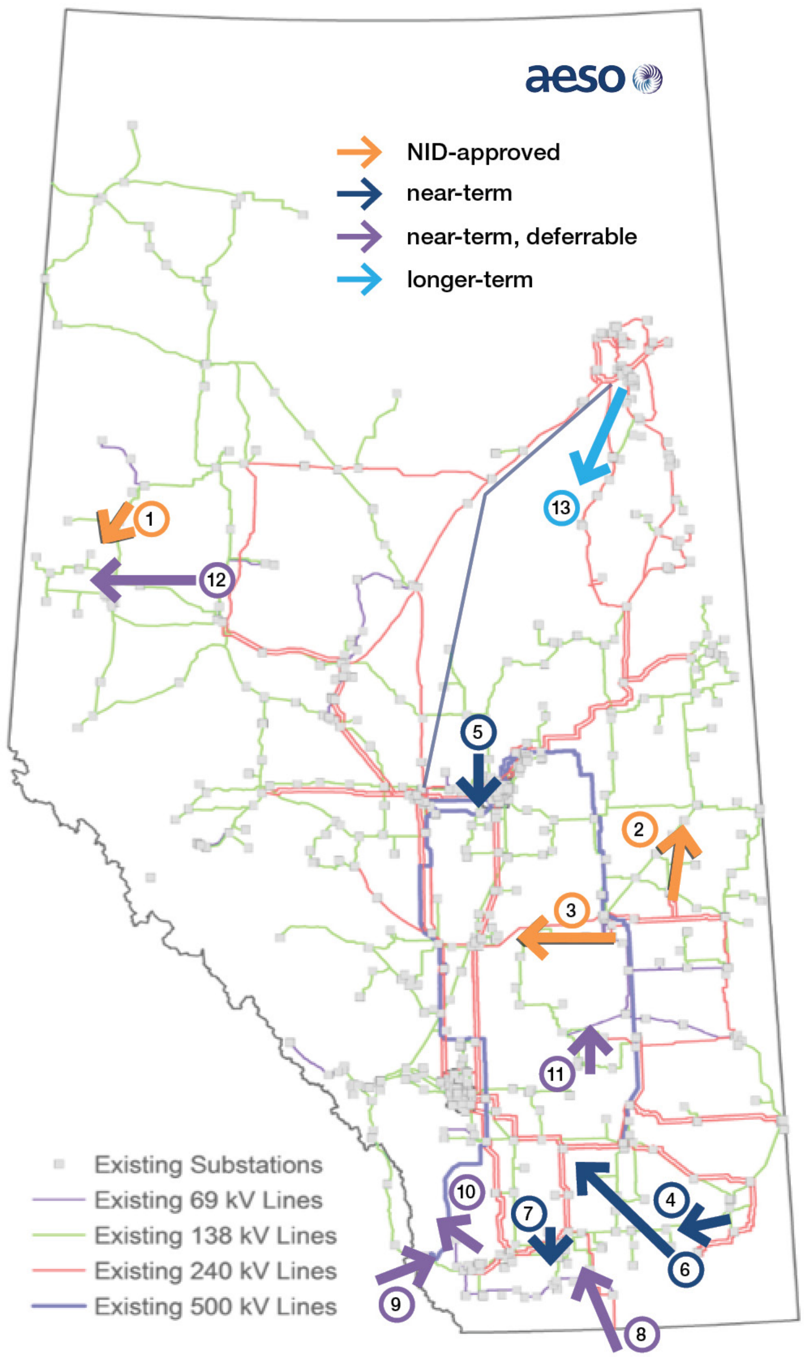
All the transmission projects identified in the LTP will still need to undergo further detailed needs analysis and alternative evaluation in order for the AESO to decide if a specific project is needed. Needed projects will then be brought forward for the AUC's approval. The pace of transmission development and needs may occur earlier or later. Therefore, the potential ratepayer impact of the 2022 LTP can also have a range based on the earlier or later requirement of all the transmission projects identified. The table below provides a range of possible transmission outcomes of the major projects from the LTP. The transmission rate impact of the major transmission projects corresponding to the earlier and later timing of transmission requirements is shown in the figure below.

Figure 1: LTP Project Costs



9.0 Conclusion

The 2022 LTP identified the following potential major transmission projects for the near-term and longer-term.



#	Type	Project	Driver	LTP. Cost Estimate ($M)	Earlier Transmission Requirement year	Later Transmission Requirement Year
1	NID Approved	Rycroft: static var compensator ("SVC") at Rycroft, in construction	Load in Grande Prairie	$40	2023	2023
2	NID Approved	PENV: two 240 kV lines in two stages, initially operated at 138 kV	Generation in Central East and Southeast & load in Central East	$293	2025	2027
3	NID Approved	CETO: one new 240 kV line between Tinchebray and Gaetz	Generation in Central East and Southeast	$310	2025	2027
4	Near Term	Vauxhall: one new 138 kV line or power flow control device	Generation in Vauxhall and Medicine Hat areas	$15	2024	2024
5	Near Term	City of Edmonton: new 240/72 kV sub and new 240 kV & 72 kV lines for the Kennedale area	Load in the City of Edmonton	$120	2025	2029
5b	Near Term Deferrable	City of Edmonton: new 72 kV lines for Hardisty and Garneau and 240 kV line between Kennedale and Victoria	Load in the City of Edmonton	$200	2042	2042
6	Near Term	SE: new 240 kV line from Whitla to Milo and substation expansion (one of three options under consideration)	Generation in Southeast	$450	2028	2029
7	Near Term	Lethbridge: new 240/138 sub and new 138 kV line	Load in Lethbridge	$40	2028	2029
8	Near Term Deferrable	MATL back-to-back direct current (DC) converter	Intertie	N/A	2030	2034
9	Near Term Deferrable	Alberta–B.C. intertie restoration: series compensation and transformer upgrade	Intertie	$100	2030	2034
10	Near Term Deferrable	CRPC area transmission: new 500/240 kV sub, new 240 kV line and SVC	Generation in Southwest	$400	2030	2034
11	Near Term Deferrable	Sheerness: new 138 kV line from Wintering Hills to Coyote Lake	Generation in Sheerness area	$35	2030	2034
12	Near Term Deferrable	Grande Prairie (GP) plan: new 240 kV line from 9L11 to Clairmont and new sub at 9L11	Load in Grande Prairie	$120	2030	2034
13	Long Term	240 kV NE plan: upgrade 9L74	Cogeneration in Fort McMurray	$60	2037	2042

10.0 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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