AESO 2025
Long-Term Transmission Plan

JANUARY 2025

Executive Summary

This LTP outlines how the AESO aims to meet Alberta's growing energy demands, support economic development, and ensure our grid operates safely, reliably and efficiently

Plan Purpose and Scope

This Long-Term Transmission Plan (LTP) presents a 20-year plan for developing Alberta's transmission system.

The plan is a comprehensive roadmap that addresses the grid's challenges and opportunities. It outlines how the AESO aims to meet Alberta's growing energy demands, support economic development, and ensure our grid operates safely, reliably and efficiently.

The LTP sets out transmission plans grouped by:

- Load-driven transmission plans (to ensure the system can serve load reliably)
- Generation-driven transmission plans (to mitigate congestion)
- Intertie-driven transmission plans (to align with government policy decisions)

In creating these plans, the LTP highlights transmission challenges that require attention and outlines strategies to address them.

Load-Driven Transmission Plans

Tables 1 and 2 below summarize the AESO's major load-driven transmission plans.

TABLE 1: Major Near-Term Load-Driven Transmission Plans (Next 5 Years)

Description	Primary Driver(s)	Cost[1] (millions)
Northwest (Grand Prairie region)		
144 kilovolt (kV) transmission development[2]	■ Load growth	$480
Northwest (Valleyview to Fox Creek region)		
144 kV transmission development	■ Load growth ■ Manage inflow constraints	$160
Edmonton[3] (in city)		
240 kV and 72 kV transmission developments	■ Load growth ■ Replace aging infrastructure	$280
South (Lethbridge region)		
240 kV and 138 kV transmission developments	■ Load growth	$45
Total		**$965**

[1] LTP cost estimates in 2025 dollars.

[2] The AESO is considering non-wires solutions as an alternative to transmission development.

[3] City of Edmonton Transmission Reinforcement (CETR) project.

TABLE 2: Major Longer-Term Load-Driven Transmission Plans (6–20 Years)

Description	Primary Driver(s)	Cost (millions)
Northwest (Grand Prairie region)		
Second line on Northwest (Grande Prairie region) near-term development and energizing to 240 kV	■ Load growth	$260
Edmonton		
Developments to reinforce city's 72 kV system	■ Load growth ■ Replace aging infrastructure	$70
Calgary		
Developments to reinforce 138 kV and 240 kV systems in and around the city	■ Load growth	$470
Total		**$800**

Generation-Driven Transmission Plans

Generation-driven transmission plans in the LTP were developed based on Alberta's current "zero congestion" planning standard. As a result, congestion mitigation is the sole purpose behind its generation-driven transmission plans.

Because of a recent government decision respecting Alberta's *Transmission Regulation* (T-Reg), the "zero congestion" planning standard for generation-driven projects will be replaced with an optimal transmission planning (OTP) framework. As outlined in the government decision, under the OTP the AESO will advance transmission projects to:

- Meet reliability requirements
- Provide an overall economic benefit

When the OTP framework is implemented, it may impact LTP generation-driven transmission plans and the potential need and timing for such developments.

The government decision will also change how transmission costs are allocated in Alberta. Currently, transmission costs are solely borne by load (customers). Costs associated with future transmission development will be allocated based on cost causation principles. In addition, new generators will contribute to transmission infrastructure costs through an upfront and non-refundable Transmission Reinforcement Payment (TRP) which will replace the current Generating Unit Owner's Contribution (GUOC) regime.

In connection with the OTP, we expect:

- OTP structure details and cost allocation decisions over 2025 and 2026
- The 2027 and future LTPs will reflect the OTP framework

Tables 3 and 4 below summarize the AESO's major generation-driven transmission plans **in the context of Alberta's current "zero congestion" planning standard**.

TABLE 3: Major Near-Term Generation-Driven Transmission Plans (Next 5 Years)

Description	Primary Driver(s)	Cost (millions)
Southeast		
New 240 kV line from Whitla to Newell and voltage support	■ Mitigate congestion	$650
Southwest		
New 500 kV line from Newell–Milo–Langdon (240 kV and 500 kV options under consideration) New 240kV line from SS-65 to Sarcee	■ Mitigate congestion	$1,850
Sheerness		
New 138 kV line from Wintering Hills to Coyote Lake	■ Mitigate congestion	$55
Total		**$2,555**

TABLE 4: Major Longer-Term Generation-Driven Transmission Plans (6–20 Years)

Description	Primary Driver(s)	Cost (millions)
Northeast		
500 kV transmission line	■ Mitigate congestion	$1,600
Southwest		
New 500/240 kV substation, 240 kV line and static VAR compensator (SVC)	■ Mitigate congestion	$450
Total		**$2,050**

Intertie-Driven Transmission Plans

The LTP's intertie-driven transmission plans are based on recent directions issued by the Government of Alberta including:

- Restore the Alberta–British Columbia (AB–BC) intertie to or near to 950 megawatts (MW)
- Procure and maintain high levels of ancillary services to support full import flows on the AB–BC intertie and the Montana Alberta Tie Line (MATL)
- Increase the path rating of the Alberta–Saskatchewan (AB–SK) intertie as part of the McNeill converter's end-of-life replacement

Tables 5 and 6 below summarize the AESO's major near and longer-term intertie-driven transmission plans.

TABLE 5: Major Near-Term Intertie-Driven Transmission Plans (Next 5 Years)

Intertie	Description	Cost (millions)
AB–BC[4]	Upgrade transformer capacity at Bennett substation and series compensating the line	$150
AB–SK	McNeill converter replacement and expansion	$600
Total		**$750**

TABLE 6: Major Longer-Term Intertie-Driven Transmission Plans (6–20 Years)

Intertie	Description	Cost (millions)
MATL	New high-voltage direct current (HVDC) back-to-back (B2B) converter[5] located at or near Picture Butte substation	N/A

New Focus Areas

Reliability Requirements

The evolution of Alberta's generation fleet to a much-increased proportion of intermittent generation has led to increased system performance and reliability challenges, including:

- Weakened frequency response (system ability to maintain and restore the balance between supply and demand by stabilizing the grid frequency after a disturbance)
- Diminished system strength (system ability to maintain stable voltages through disturbances such as faults, sudden changes in load or the loss of a generator)
- Reduced flexibility (system ability to adapt and respond to changes in electricity supply and demand in real-time)

The AESO published its plans regarding system performance and reliability in its ***Reliability Requirements Roadmap***. Transmission infrastructure development is one of several potential solutions to the grid challenges identified in the roadmap. Costs and operational characteristics of all potential solutions will be assessed prior to pursuing transmission infrastructure development.

4 Alberta–British Columbia Intertie Restoration (AIR) plan.

5 The AESO plans to use fast frequency response to restore import capability—the B2B project is a potential alternative.

Alternative Potential Solutions

Among other solutions, we are considering:

- Fast frequency response (FFR) technologies to increase frequency stability
- Generator control tuning, synchronous condenser or grid-forming battery energy storage systems (BESS) to increase system strength
- New ancillary services to increase flexibility

We will release our next *Reliability Requirements Roadmap* in 2025. It will provide updates on these potential grid reliability solutions.

Data Centres

In 2024, several data centre projects, representing more than 8,600 MW in capacity, submitted connection applications to the AESO. Due to the data centre projects' early stages of development and the recency of their submissions, the LTP does not include transmission plans for these potential loads.

As the data centre applications progress through our connection process, we will develop transmission plans driven by these large, discrete, and localized load additions.

As we move forward with potential data centre-driven transmission plans, we will ensure reliable data center integration into the grid. To that end, we are:

- Reviewing Alberta's regulatory framework, Independent System Operator (ISO) tariff and our connection process requirements
- Developing data centre study, modelling and technical requirements
- Producing a location-based load capability map
- Participating in Federal Energy Regulatory Commission (FERC) and ISO/Regional Transmission Organization (RTO) Council analyses and initiatives to assess and address the impacts of large loads on the electricity grid

Potential Transmission Cost Impact

Alberta's transmission costs are made up of:

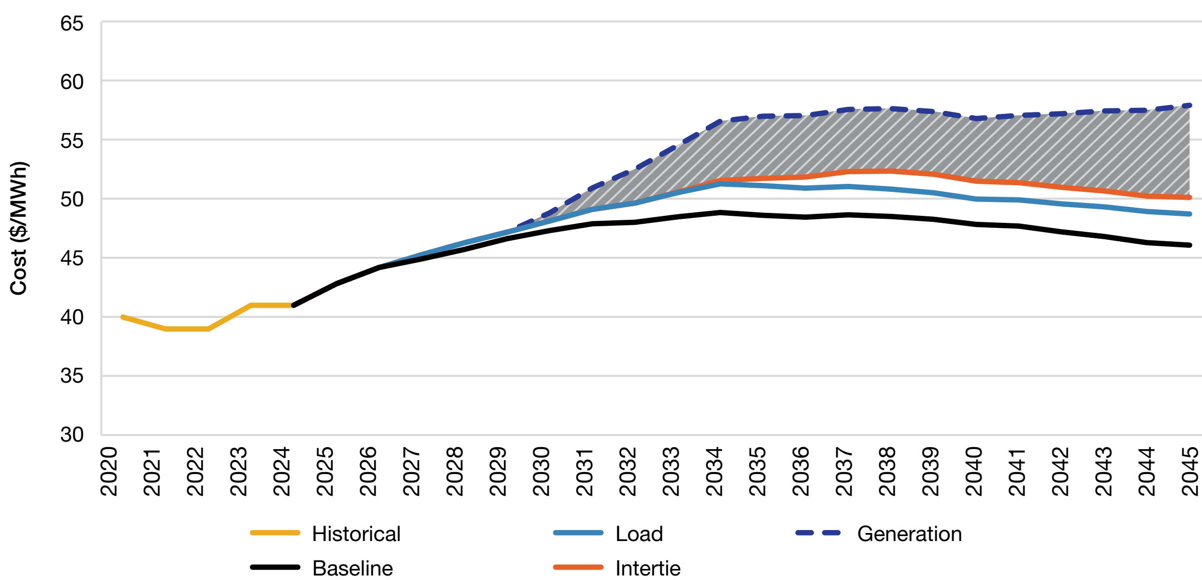
- Alberta Utilities Commission (AUC) approved transmission revenue requirements for transmission facility owners (TFOs) which include returns on and of capital and system maintenance and operating costs
- Ancillary services cost
- A portion of AESO costs[6]

[6] Remainder of AESO costs are allocated to the AESO trading charge.

Figure 1 below illustrates how each type of transmission plan identified in the LTP (load-driven, generation-driven, intertie-driven) contributes to transmission costs relative to baseline costs. The baseline curve includes all AUC-approved and under construction AESO transmission projects.

The impact generation-driven transmission plans will have on transmission costs will be influenced by the OTP's design. Under OTP, we expect some plans will proceed while others may not. As a result, generation-driven transmission plans are modelled as a range.

FIGURE 1: Transmission Cost Impact[7]



Our estimated 2025 transmission cost is $43/megawatt hour (MWh) which we expect to increase to $47/MWh by 2029. Thereafter, transmission costs will depend on OTP implementation. If all generation-driven transmission plans were to proceed to AUC-approved projects, the transmission costs could be $58/MWh by 2045.

Affordability

The AESO is exploring alternative solutions and innovative technologies to minimize transmission costs, including:

- Mitigating transmission line constraints by, for example, replacing limiting substation equipment, resolving clearance issues, or reconductoring to a higher capacity
- Remedial action schemes (RAS)
- Dynamic line rating (DLR) technologies
- Power flow control devices to re-direct power to less-utilized transmission facilities
- Non-wires solutions including energy storage
- Pursuing supplemental funding

[7] Estimated average cost per MWh of the entire transmission system (does not reflect specific ISO Tariff customer rates) – nominal dollars.

Contents

Background

This LTP presents a 20-year plan for developing Alberta’s transmission system ensuring safe, reliable and efficient operations

The AESO is mandated by provincial regulation to prepare and maintain a transmission system plan that projects for at least the next 20 years:

- Forecast load
- Anticipated generation capacity
- Timing and location of future generation additions
- Transmission facilities required to:
  - meet forecast load, imports and exports of electricity and anticipated generation facilities
  - provide for efficient and reliable access to jurisdictions outside Alberta

As required by regulation, this LTP presents a 20-year plan for developing Alberta's transmission system to ensure it operates safely, reliably and efficiently.

The LTP:

- Incorporates the *AESO 2024 Long-Term Outlook* (LTO)
- Sets out transmission plans grouped by:
  - Load-driven transmission plans (to ensure the system can serve load reliably)
  - Generation-driven transmission plans (to mitigate congestion)
  - Intertie-driven transmission plans (to align with government policy decisions)
- Is developed in concert with our *Reliability Requirements Roadmap* which may identify additional transmission infrastructure or ancillary services needs

Changing Transmission Policy

The AESO currently plans for a "zero congestion" system per Section 15(1)(e)(i) of the ***Transmission Regulation* (T-Reg)**. This regulation requires the AESO to:

> *…plan a transmission system that (i) is sufficiently robust so that 100% of the time, transmission of all anticipated in-merit electric energy referred to in section 17(c) of the Act can occur when all transmission facilities are in service…*

In July 2024, the **Government of Alberta (GoA) directed the AESO** to:

- Move to an optimally planned transmission planning standard (OTP)
- Allocate new transmission infrastructure and ancillary services costs based on cost causation principles[8]

Subsequently, in a **December 2024 direction letter**, the GoA provided further guidance to:

- File a Needs Identification Document (NID) Application for the Alberta Intertie Restoration (AIR) project by December 31, 2026, to restore the Alberta–British Columbia (AB–BC) intertie to, or near to, 950 megawatt (MW)
- Procure and maintain high levels of ancillary services to support the full import flows on the AB–BC intertie and the Montana–Alberta Tie Line (MATL)
- Increase the path rating of the Alberta–Saskatchewan (AB–SK) intertie as part of the McNeill converter's end-of-life replacement

[8] Requiring new generators to contribute to transmission infrastructure costs by replacing Generating Unit Owner's Contribution (GUOC) with an upfront and non-refundable Transmission Reinforcement Payment (TRP).

Changing Grid Reliability

Since the AESO's 2022 LTP, the system has seen important changes, including:

- Aging transmission infrastructure has become a more pressing issue
- Increasing operational complexity is heightening the need for transmission development
- Coal-fired electricity generation phased out in 2024
- A substantial rise in the share of intermittent generation within the generation fleet—increasing challenges to reliability, particularly in areas such as frequency stability, system strength and flexibility

In response to these changes, the AESO has been actively developing grid reliability solutions as outlined in its *Reliability Requirements Roadmap*. These initiatives may include expanding transmission infrastructure, enhancing fast frequency response (FFR) to enhance frequency stability and procuring new ancillary services to improve system flexibility.

Transmission Plans

Load-Driven Transmission Plans

The AESO's load-driven transmission plans prioritize development in the next five years to ensure loads are served reliably.

Generation-Driven Transmission Plans

Generation-driven transmission plans in the LTP were developed based on Alberta's current "zero congestion" planning standard. As a result, congestion mitigation is the sole purpose behind its generation-driven transmission plans.

Because of a recent government decision respecting Alberta's T-Reg, the "zero congestion" planning standard for generation-driven projects will be replaced with an optimal transmission planning (OTP) framework. As outlined in the government decision, under the OTP the AESO will advance transmission projects to:

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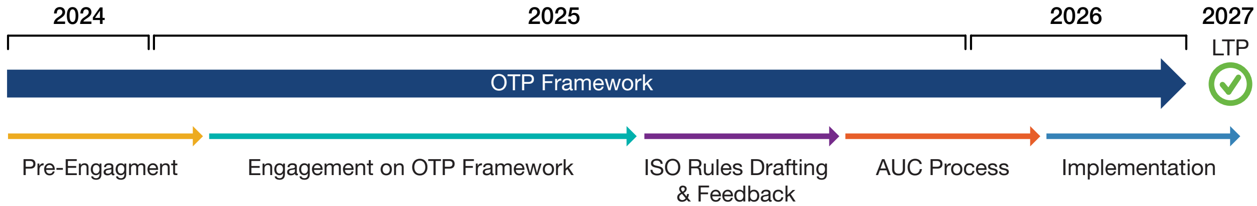
The government decision will also change how transmission costs are allocated in Alberta. Currently, transmission costs are solely borne by load (customers). Costs associated with future transmission development will be allocated based on cost causation principles.

In connection with the OTP, we expect:

- OTP structure details and cost allocation decisions over 2025 and 2026
- The 2027 and future LTPs will reflect the OTP framework

Figure 2 below illustrates the AESO's expected OTP framework development and implementation timeline.

FIGURE 2: OTP Implementation Timeline



Intertie-Driven Transmission Plans

The LTP's intertie-driven transmission plans are based on recent directions issued by the GOA including:

- Restore the AB–BC intertie to, or near to, 950 MW
- Procure and maintain high levels of ancillary services to support full import flows on the AB–BC intertie and the MATL
- Increase the path rating of the AB–SK intertie as part of the McNeill converter's end-of-life replacement

LTP Supporting Resources

The LTP has changed in response to industry and stakeholder inputs and incorporates information from or is complemented by other AESO resources

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Table 7 below outlines the connections between other AESO documents and the LTP.

TABLE 7: LTP Supporting Resources

Purpose	Relationship to the LTP
Long-Term Outlook	
Provide 20-year load and generation forecast	Provides LTP's regulatorily-required: ■ forecast load ■ anticipated generation capacity ■ timing and location of future generation additions
Connection and Cluster Process	
Facilitate market participants' requests for new or altered system access services Cluster Assessment Reporting provides congestion risk information	■ Early input to the LTO and the LTP ■ Provides strong signals on location, size, types, and interests of potential load and generation project developments
Transmission System Capability Map[9]	
Provide transmission capacity insights across Alberta regions	■ Augments LTP transmission system capability perspectives
Reliability Requirements Roadmap	
Identify system operating challenges	■ Supports transmission development needs

[9] The Transmission Capability Map covers planning areas with the most significant project interest.

LTP Stakeholder Engagement

The AESO's Stakeholder Engagement Framework provides a strategic, principle-based stakeholder engagement process used in developing the LTP

The AESO's **Stakeholder Engagement Framework** provides a strategic, principle-based stakeholder engagement process used in developing the LTP. Consultations are conducted to provide stakeholders, including government and agency partners, with information and gather feedback to facilitate informed development of the LTP.

Table 8 below outlines the **key engagement** activities the AESO completed as part of its LTP development process.

TABLE 8: AESO LTP Stakeholder Engagement Activities

Date	Engagement Activity	Purpose/Outcome
March 2023	Online written survey	Gathered early stakeholder input on the AESO's LTP plan, objectives and scope
April 2023	Summary of survey responses	Published online summary of themed survey responses
November 2024	Grid Reliability information session	Updated stakeholders on grid reliability and LTP developments

The AESO's LTP Process

LTO load and generation forecasts are input into the AESO's transmission planning models to develop base cases, sensitivities and stress-test cases

The AESO prepares the LTP every two years. The LTP uses scenarios developed in the LTO to consider potential future market conditions. LTO load and generation forecasts are input into the AESO's transmission planning models to develop base cases, sensitivities, and stress-test cases.

Following that work, the AESO then conducts regional engineering studies.

The LTP assesses the transmission system using the following timeframes:

- **Near-Term (next 5 years)**
  - Transmission system (69 kilovolt [kV]+) analyzed in greater detail
  - Enables the AESO to understand regional needs with reasonable certainty in load and generation developments
  - Identifies needed transmission developments to mitigate violations of system limits
- **Longer-Term (6–20 years)**
  - Examines transmission system on a bulk, system-wide basis
  - Focuses on 240 kV and 500 kV system contingencies, monitoring impact on 138 kV and larger infrastructure
  - Identifies potentially needed transmission developments to mitigate violations of system limits
  - Identifies potential concerns in LTO-developed scenarios

The AESO monitors system performance and prioritizes developments destined to support grid reliability. When the AESO's analysis identifies the need to proceed with a development it:

- Initiates a system project
- Undertakes detailed project analysis and alternative evaluations
- Prepares and files a NID Application with the Alberta Utilities Commission (AUC) to obtain project approval

Transmission project energizations can take two to seven years.

LTO Scenarios Evaluated in the LTP

The LTP evaluates four scenarios developed in the AESO's 2024 LTO, including:

- Reference Case
- Decarbonization by 2035
- Alternative Decarbonization
- High Electrification

Table 9 below summarizes the 2024 LTO's four scenarios.

The Reference Case serves as the base scenario for the AESO's transmission planning assessment.

We also developed additional scenarios based on the LTO's Decarbonization by 2035, Alternative Decarbonization and High Electrification scenarios to capture uncertainties stemming from the pace and extent of electrification, new generation technologies, increased intertie connections, and the federal government's proposed *Clean Electricity Regulations* (CER).[10]

The LTO Reference Case projects that peak load growth will average an annual rate of 1.4 per cent over the next 20 years.

[10] Released in Canada Gazette 1.

TABLE 9: LTO Scenarios at a Glance

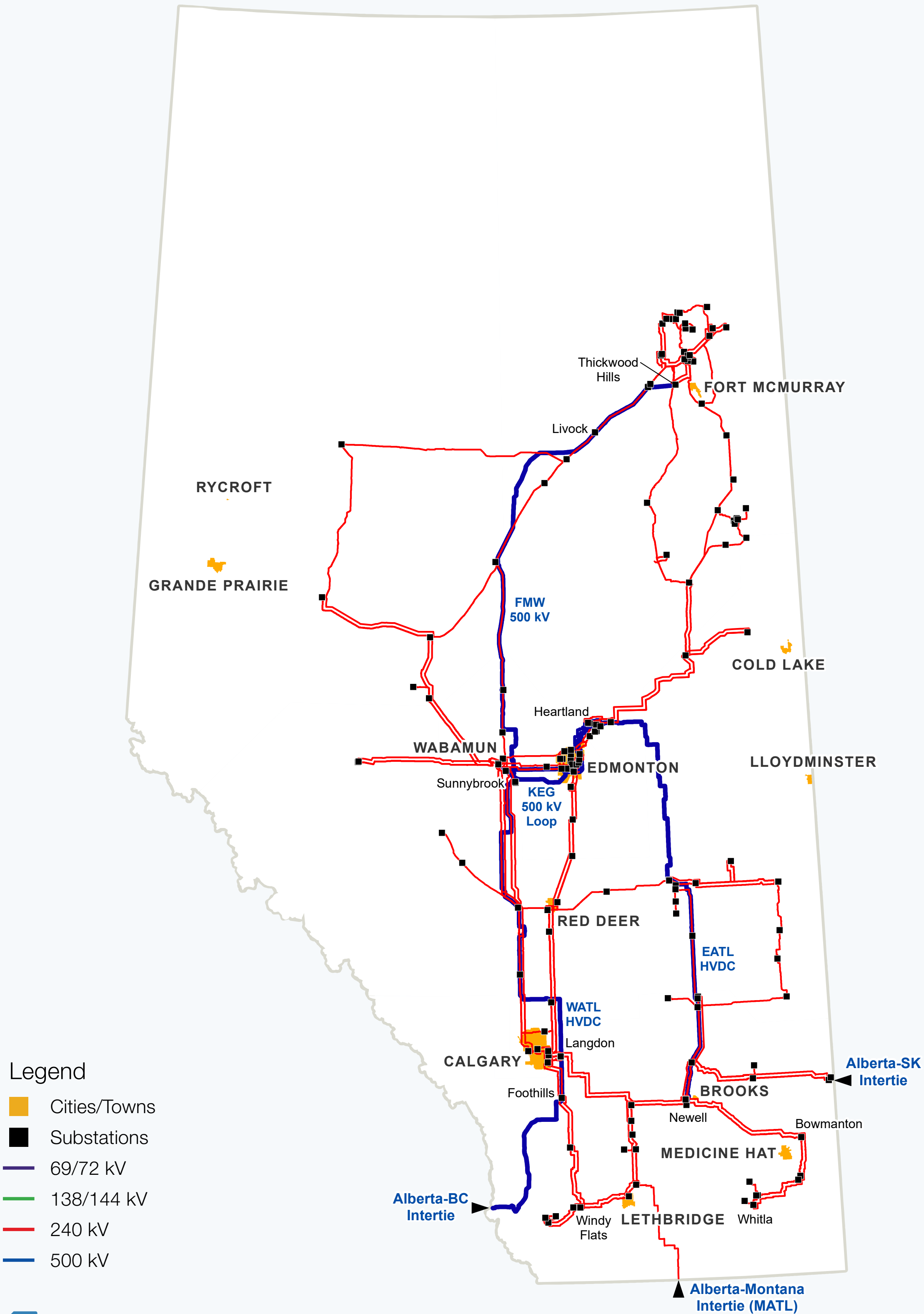
Description	Load	Generation
Reference Case		
■ Covers key economic and oil sands outlooks, electrification trends, and recent advancements in generation technology and costs ■ Decarbonization by 2050	■ Near-term load is driven by macro factors like gross domestic product, employment and population trends ■ In the longer-term electric vehicle (EV) adoption, hydrogen production and building electrification drive load growth	■ Driven by wind and solar additions and combined-cycle and cogeneration carbon capture, utilization and storage (CCUS) retrofits. ■ Several nuclear small modular reactor (SMR) baseload projects in the longer-term
Decarbonization by 2035		
■ Assumes the federal CER restrictions as released in Gazette 1 ■ Targeting decarbonization by 2035	■ Same load profile as the Reference Case	■ Higher development of alternative technologies, like hydrogen-fired simple-cycle and new combined-cycle with CCUS facilities
Alternative Decarbonization		
■ Increasing intertie connections with neighbouring jurisdictions	■ Same load profile as the Reference Case	■ Greater reliance on power imports via the BC intertie enabled by its increased capacity. ■ Lowest longer-term capacity buildout
High Electrification		
■ Accelerated residential, commercial and industrial electrification	■ Greater adoption of EVs and electrification of building heating and cooling ■ Additional industrial loads (hydrogen production)	■ Increased baseload generation technologies – new and retrofit combined-cycle with CCUS ■ Greater nuclear SMR development in the longer-term

Existing System and Active Developments

Alberta's grid has evolved in response to the province's population growth, industrial development and changing generation supply

Alberta System and Recent Developments

FIGURE 3: Existing System



View SLDs: aseo.ca/grid/LTP

High-Level Summary

1950s–1990s

- A backbone of 240 kV alternating current (AC) transmission lines connects Calgary, Red Deer and Edmonton, supporting one-third of Alberta's load
- In the 1950s, the Wabamun Lake area near Edmonton became a generation hub driven by thermal coal-supplied power generation facilities. Roughly 4,500 MW of coal-fired generation was built in the area supported by the Keephills–Ellerslie–Genesee (KEG) 500 kV loop system

  ⓘ For decades, the 240 kV backbone transferred excess electricity to Calgary and southern Alberta
- Since the 1990s, Alberta's southern region has become a centre for renewables generation with accelerated growth in wind and solar generation
- Asset aging, less attractive economics and federal legislation led to the retirement of Alberta's coal-fired generation fleet in 2024 and the conversion of some to gas-fired generation
- These recent changes resulted in the Edmonton–Calgary transmission backbone supporting bidirectional power flow

  ⓘ Excess power moves south to north during periods of high wind and solar generation, while dispatchable generators supply demand with north-to-south transfers when wind and solar generation are inactive

2000s–Present

- Energized in late 2015, the 500 kV high-voltage direct current (HVDC) lines, Eastern Alberta Transmission Line (EATL) and Western Alberta Transmission Line (WATL) enable bi-directional controllable power transfers of up to 1,000 MW between Edmonton and Calgary
- Southern Alberta's network of 240 kV transmission lines provides grid access for wind and solar generation facilities; they also deliver electricity to Lethbridge, Medicine Hat and throughout southern Alberta.
- Recent projects include the Southern Alberta Transmission Reinforcement (SATR) and the Foothills Area Transmission Development (FATD)
- The SATR development included 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)
- The FATD development strengthened the Foothills and Calgary connection and facilitated the interconnection of the Shepard Energy Center 868 MW combined-cycle generating station (near Calgary) which began operations in 2015
- Northeast Alberta has substantial electricity needs driven by its major oil sands operations; the region benefited from the Heartland 500 kV Transmission Development which integrated the north terminal of EATL with the KEG 500 kV loop system and which strengthened supply into the Edmonton region

  ⓘ The region is served by two 240 kV transmission lines northeast of Edmonton and a 240 kV tie in the northwest.
- The Fort McMurray West 500 kV transmission line, energized in 2019, expanded electricity supply for oil sands operations by connecting Sunnybrook (WATL's north terminal) to the new Thickwood Hill substation

  Other recent transmission developments include:
- Voltage support equipment added at Rycroft 730S to accommodate demand growth and ensure reliability
- Capacitor banks installed at the 240 kV Bowmanton 244S substation for area voltage support

Interties

Alberta has a weakly connected grid with three neighboring jurisdictions, British Columbia to the west, Montana to the south, and Saskatchewan to the east.

AB–BC and MATL

Alberta has two AC interties, the AB–BC intertie and the MATL. The main element of the BC intertie is the 500 kV line from Cranbrook, BC to Langdon (near Calgary). The BC intertie also has two low-capacity 138 kV elements.

MATL is a 230 kV intertie from Great Falls, Montana to Picture Butte, Alberta (near Lethbridge).

AB–SK

The Alberta and Saskatchewan systems are interconnected through the AB–SK intertie and the McNeill back-to-back HVDC converter station.

The McNeill converter, commissioned in 1989, provides 150 MW of import and export capability between the provinces.

Since Alberta is part of the Western Interconnection and Saskatchewan is part of the Eastern Interconnection, the intertie between the provinces must be asynchronous (direct current).

Current Transmission Developments

Several NID-approved transmission projects are underway in Alberta. Table 10 below summarizes those projects.

TABLE 10: Projects in Active Development

Purpose	Timing
Vauxhall Area Transmission Development (VATD)	
Increase system capability to integrate new generation on the local 138 kV system	■ Under construction ■ Anticipated in-service date: Q1 2025
Central East Transfer-Out (CETO)	
Facilitate increased generator grid connections on the east side of the province between Edmonton and Calgary	■ Under construction ■ Anticipated in-service date: Q2 2026
City of Edmonton Transmission Reinforcement (CETR)	
Respond to load growth and facilitate end-of-life asset decommissions	■ NID application approved in September 2024 ■ Anticipated in-service date: 2027
Provost to Edgerton and Nilrem to Vermilion (PENV)	
Increase system capability to integrate renewable generation growth and to serve load in the central east	■ The AESO is monitoring developments in the area which may drive development needs
Chapel Rock to Pincher Creek (CRPC)	
Increase system capacity to transfer power from wind and solar generation in the south to the Calgary region and to strengthen the AB–BC intertie	■ Project timing depends pace of generation developments in the southwest and intertie restoration plans

Regional Transmission Plans (Reference Case)

Regional studies support the AESO's 20-year plan to address load, generation and intertie needs

Northwest Planning Region

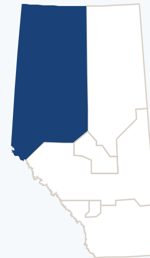
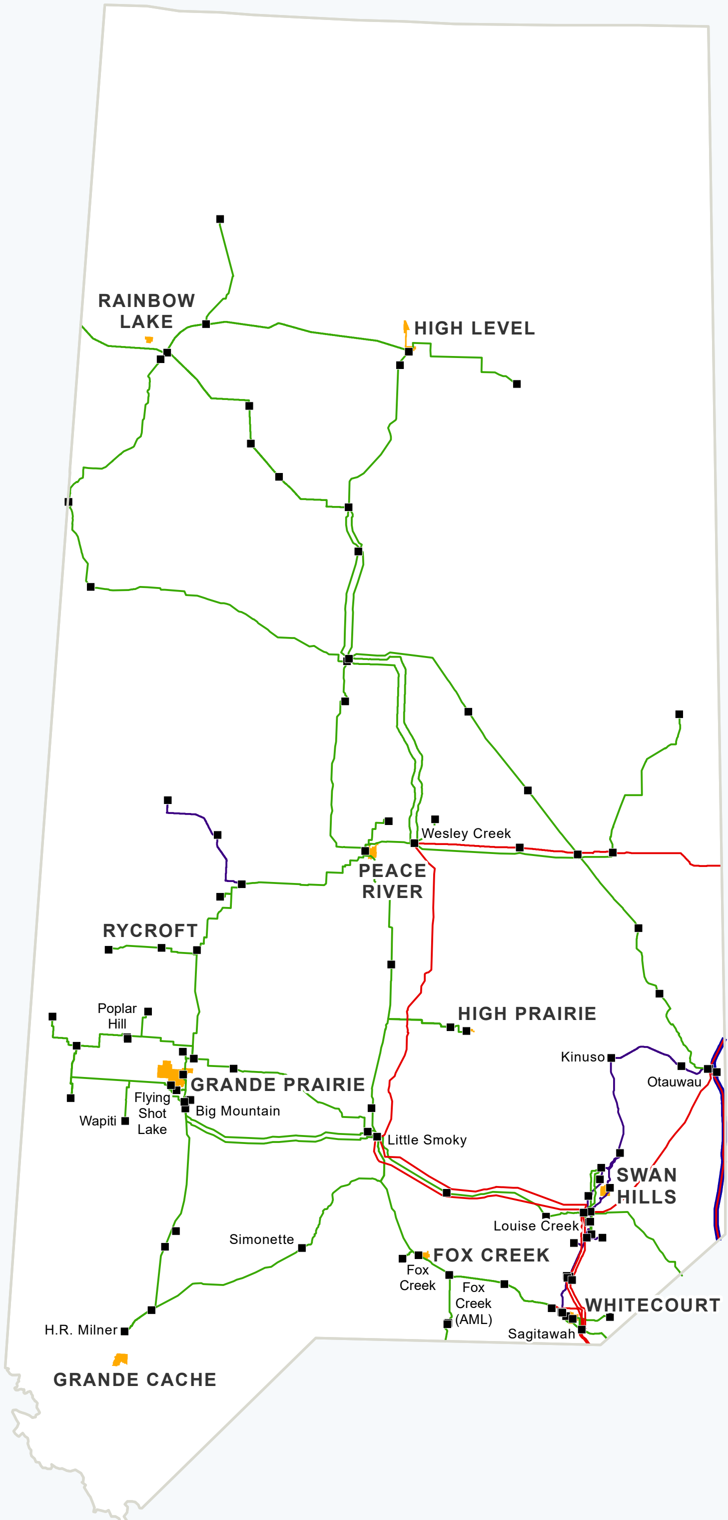


FIGURE 4: Northwest Planning Region



Legend

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

View SLDs: aeso.ca/grid/LTP

Overview and Forecast

Load Characteristics

- **1,185 MW** regional peak
  - Largely industrial, with some residential, commercial, and agricultural loads
- Reference Case forecasts an average peak load growth rate of **0.94 per cent** annually over the 20-year planning timeframe

Generation Characteristics

- **1,282 MW** installed capacity
  - **Two-thirds** from gas-fired resources
  - **100 MW** of battery energy storage systems (BESS) introduced since 2020
- Near-term forecast includes CCUS retrofit to existing combined-cycle and cogeneration units and includes **50 MW** of BESS capacity
- Longer-term forecast considers **900 MW** of nuclear SMR additions

TABLE 11: Northwest Planning Region Load and Generation Capacity Forecast

Load/Supply	Change in Load/Supply Over Time		
	Existing (MW)	Near-Term (MW)	Longer-Term (MW)
Region Peak Load	**1,185**	**1,292**	**1,414**
Coal-to-gas	0	0	0
Cogeneration	162	162	51
Cogeneration with CCUS retrofit	0	0	103
Hydrogen-fired cogeneration	0	0	93
Combined-cycle	373	73	73
Combined-cycle with CCUS retrofit	0	270	270
Simple-cycle	440	440	525
Hydrogen-fired simple-cycle retrofit	0	0	50
Hydroelectric	0	0	0
Nuclear SMR	0	0	900
Wind	0	0	100
Solar[11]	0	0	0
Other	207	207	207
Storage	100	150	0
Total Generation Capacity	**1,282**	**1,302**	**2,372**

[11] This does not include rooftop solar, which is considered within the load forecast.

Existing Transmission System

The Northwest planning region is primarily served by a 240 kV system that transfers power into the region from the Wabamun Lake area and the Northeast. Local load is served by a 144 kV system connected by several 240kV substations (Louise Creek, Little Smoky, Wesley Creek, Sagitawah, Bickerdike, Mitsue and North Barrhead). 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 addition of voltage support at Rycroft 730S substation project was energized in May 2023

Opportunity to Connect New Generation and Congestion Risk[12]

- The 240 kV system can accommodate a significant amount of new generation, given constraints are primarily driven by inflow conditions
- The 138/144 kV system could also benefit from incremental generation development to help reduce inflow constraints
  - However, the limited thermal capacity of the system poses a challenge when trying to accommodate large generation projects
- Congestion risk in the region is linked to flow into the Northwest, particularly along the 138 kV paths between Bickerdike[13]–Little Smoky–Grande Prairie

[12] Previously, the LTP included comprehensive information on the province's transmission system capability and congestion risk. This data is now available through separate AESO products, the Transmission Capability Map and Cluster Assessment Reporting.

[13] Located in the Central planning region.

Near-Term Transmission Plans

Grande Prairie Area

- To address forecasted load growth in the Grande Prairie area, a 144 kV transmission line constructed to a 240kV standard is likely needed to alleviate thermal and voltage violations
- The new transmission line would connect the Poplar Hill area to Little Smoky substation, following the existing 144 kV path from Poplar Hill through Flying Shot and Big Mountain-Little Smoky
- Should load growth materialize sooner than forecast, there could be a need to accelerate the longer-term plans which call for an additional 240 kV reinforcement
- The AESO is also evaluating non-wires solutions

Valleyview to Fox Creek Area

- To alleviate thermal violations in the Fox Creek area under system normal and outage conditions a 144 kV transmission line constructed to a 240kV standard connecting Little Smoky to Fox Creek may be needed under high load and low internal generation dispatch in the surrounding area
- To increase transfer-in capability and address future load growth in the Northwest region, a potential plan would further connect Fox Creek to Bickerdike

Little Smoky Substation

- Additional transformation capacity is required at the Little Smoky substation
  - If one transformer at the Little Smoky substation is out of service, the other may become overloaded
- Mitigation options include adding a third transformer or replacing both existing transformers with larger units

Grande Cache Area

- Low voltages were observed in the Grande Cache area under low internal generation
- Voltage support (such as capacitor banks) may be required

High Prairie Area

- Low voltages were observed in the High Prairie area under various transmission contingencies
- Voltage support (such as capacitor banks) may be required

TABLE 12: Summary of Near-Term Plans (Next 5 Years)

Description	Primary Driver(s)
Grande Prairie Area	
Build a new 240/144 kV substation in the Poplar Hill area Build a new 240 kV line from the new Poplar Hill substation to Little Smoky 813S, initially operated at 144 kV	■ Load growth
Valleyview to Fox Creek Area	
Build a new 240 kV line from Little Smoky 813S to Fox Creek 741S, initially operated at 144 kV	■ Load growth ■ Manage inflow constraints
Little Smoky Substation	
Replace existing 240/144 kV transformers with higher-capacity units (or add a third unit) at Little Smoky 813S	■ Load growth
Grande Cache Area	
Voltage support device at H.R. Milner 740S and/or Simonette 733S	■ Load growth
High Prairie Area	
Voltage support device at Kinuso 727S	■ Load growth

Longer-Term Transmission Plans

Forecasted load growth in the Grande Prairie area signals additional transmission developments beyond those outlined in the near-term plan. A 240 kV line between Poplar Hill and Little Smoky is the longer-term solution, providing the needed capability and flexibility to support load growth.

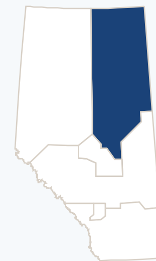
The Northwest represents a region with possible interest in large nuclear development. Further analysis will be needed to identify corresponding transmission plans to increase transfer-out capability.

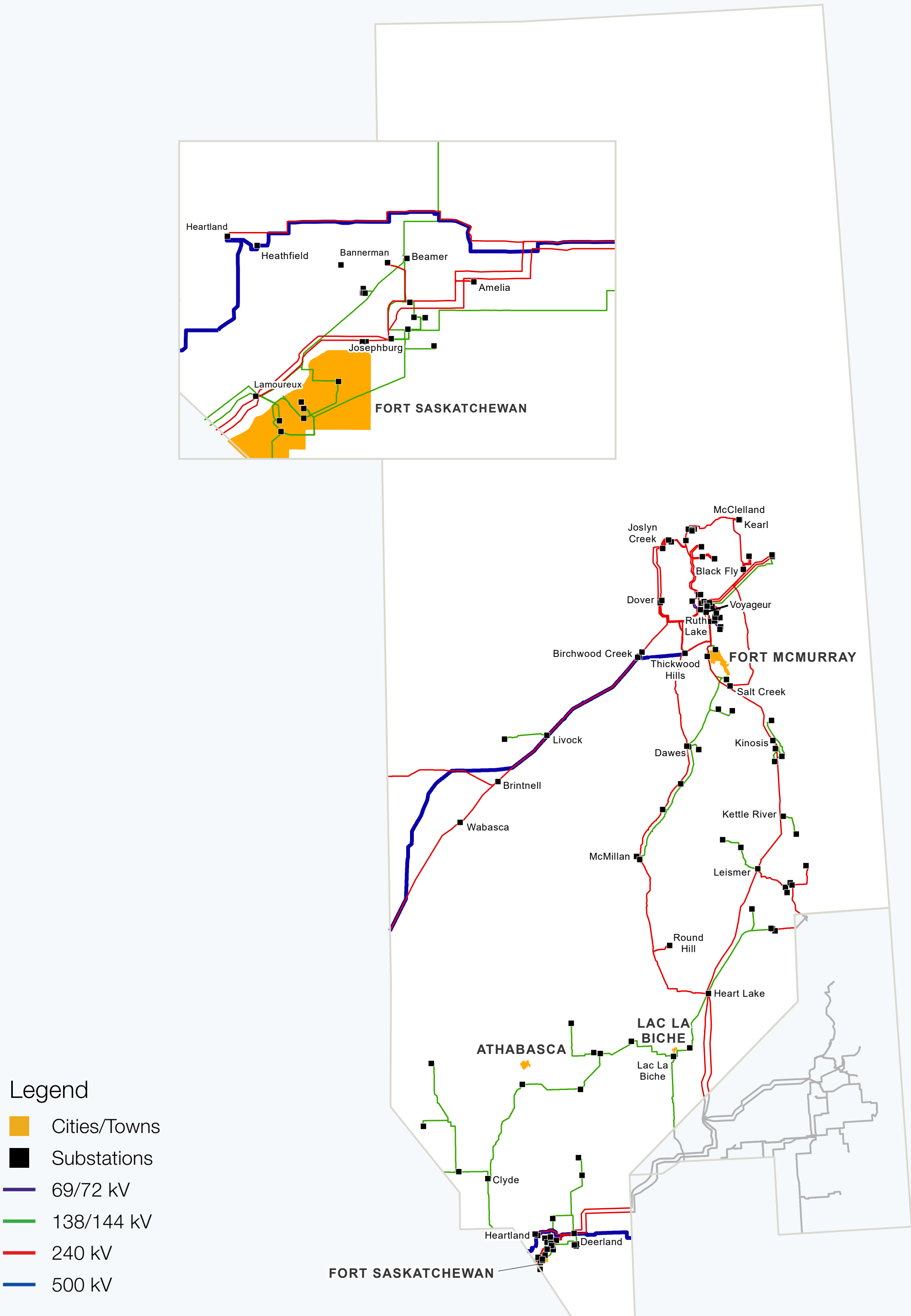
TABLE 13: Summary of Longer-Term Plans (6–20 Years)

Description	Primary Driver(s)
Grande Prairie Area	
Add a second line to the 144 kV line between the new Poplar Hill substation to Little Smoky 813S and energize to 240 kV Add a 240kV switching station at Flyingshot Lake 749S	■ Load growth

Northeast Planning Region

FIGURE 5: Northeast Planning Region





View SLDs: aeso.ca/grid/LTP

Overview and Forecast

Load Characteristics

- **3,600 MW** regional peak
  - Significant oil sands development in the Fort McMurray area
- Reference Case forecasts an average peak load growth rate of **0.11 per cent** annually over the 20-year planning timeframe

Generation Characteristics

- **4,707 MW** installed capacity
  - Mostly in the form of cogeneration
- Near-term forecast includes CCUS retrofits to existing cogeneration units and some hydrogen-fired cogeneration
- Longer-term forecast considers **900 MW** of nuclear SMR additions

TABLE 14: Northeast Planning Region Load and Generation Capacity Forecast

Load/Supply	Change in Load/Supply Over Time		
	Existing (MW)	Near-Term (MW)	Longer-Term (MW)
Region Peak Load	**3,600**	**3,774**	**3,669**
Coal-to-gas	0	0	0
Cogeneration	4,500	1,418	10
Cogeneration with CCUS retrofit	0	2,977	4,607
Hydrogen-fired cogeneration	0	140	140
Combined-cycle	0	0	0
Combined-cycle with CCUS retrofit	0	0	0
Simple-cycle	0	0	326
Hydrogen-fired simple-cycle retrofit	0	0	0
Hydroelectric	0	0	0
Nuclear SMR	0	0	900
Wind	0	0	0
Solar[14]	58	58	58
Other	149	149	149
Storage	0	0	0
Total Generation Capacity	**4,707**	**4,742**	**6,189**

[14] This does not include rooftop solar, which is considered within the load forecast.

Existing Transmission System

The Northeast planning region transmission system consists of a 240 kV system primarily serving large industrial operations in the Fort McMurray and Fort Saskatchewan areas and a high-capacity 500 kV connection to the Edmonton region. In addition, local 138/144 kV systems serve load across the planning region.

TRANSMISSION PROJECT STATUS

The 807L (Beamer–Shell) Capacity Increase 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 defer the rebuild
- The AESO continues to monitor thermal loading in the area and will direct the transmission facility owner (TFO) to begin construction for the approved facilities when it determines that operational measures will not sufficiently manage the overload and constraints in the area

Opportunity to Connect New Generation and Congestion Risk[15]

- With material cogeneration projects connecting in the near term, the AESO anticipates the region will be a net producer of energy in the future and the need will exist to transfer excess energy out of the region
- The Fort McMurray West transmission line, energized in 2019, added substantial transfer-out capacity to the Northeast.
  - However, with the recent energization of the Suncor Base Plant cogeneration project, 850MW, at Voyageur substation and forecasted generation connections, transmission limitations may manifest
- In the near-term, limitations can be mitigated using the Phase Shifting Transformer (PST) located at the Livock substation
- In the longer term, with the scale of forecasted new cogeneration and SMR integration, additional transmission development may be required to mitigate congestion

Near-Term Transmission Plans

McClelland Substation

- Low voltages may occur at the Kearl substation in contingency conditions involving high load and generator outages
- Currently, a remedial action scheme (RAS) is in place to mitigate voltage violations. A capacitor bank at McClelland is another potential mitigation solution.

[15] Previously, the LTP included comprehensive information on the province's transmission system capability and congestion risk. This data is now available through separate AESO products, the Transmission Capability Map and Cluster Assessment Reporting.

Fort McMurray Area

- The 850 MW Suncor Base Plant cogeneration project was recently energized at Voyageur substation
- The addition was integrated with the utilization of RAS to mitigate thermal overloads on the 240 kV system after the loss of the Fort McMurray West 500 kV line
- The PST at Livock can also be utilized pre-contingency to mitigate overloads

TABLE 15: Summary of Near-Term Plans (Next 5 Years)

Description	Primary Driver(s)
McClelland Substation	
Voltage support device at McClelland 957S	- Load growth

Longer-Term Transmission Plans

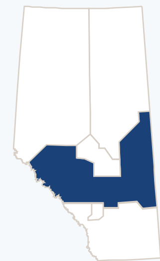
Should significant generation additions, such as the SMR capacity considered in the LTO, arise in the area, the new 500 kV Fort McMurray East transmission is a potential plan to increase transfer-out capability.

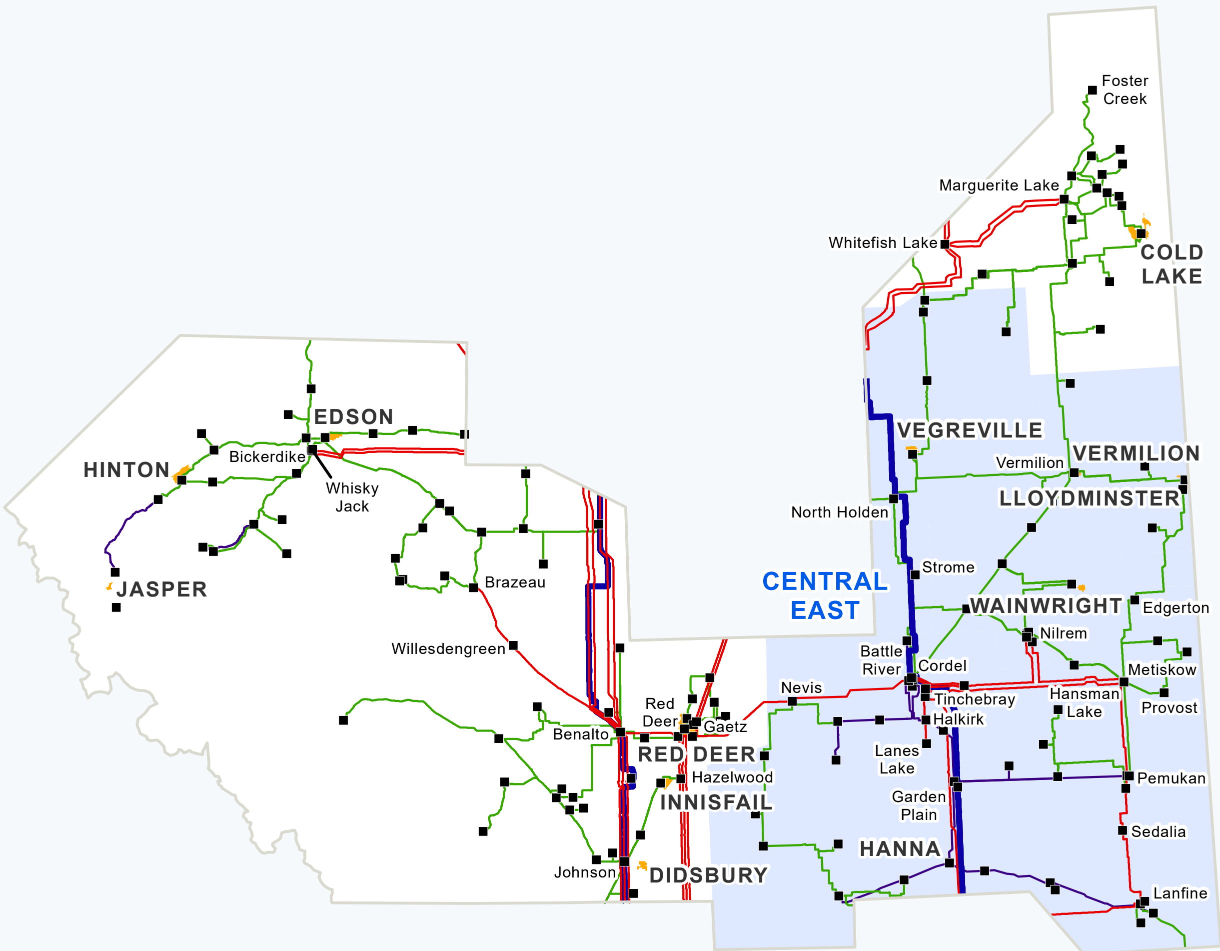
TABLE 16: Summary of Planned Developments

Description	Primary Driver(s)
Fort McMurray Area	
New 500 kV line between Heartland 12S and Thickwood Hills 951S	- Mitigate congestion

Central Planning Region

FIGURE 6: Central Planning Region





Legend

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

View SLDs: aeso.ca/grid/LTP

Overview and Forecast

Load Characteristics

- **2,187 MW** regional peak
  - Notable amounts of manufacturing and significant oil sands development to the east in the Cold Lake area
- Reference Case forecasts peak load growth rate of **0.92 per cent** annually over the 20-year planning timeframe

Generation Characteristics

- **4,924 MW** installed capacity
  - Has seen significant growth in wind power and gas-fired combined-cycle capacity over the past decade
- Near-term forecast includes CCUS retrofit to existing combined-cycle and cogeneration units
- Renewables and storage are expected to continue to grow, with approximately **1,500 MW** of renewables and **222 MW** of storage developing over the 20-year forecast

TABLE 17: Central Planning Region Load and Generation Capacity Forecast

Load/Supply	Change in Load/Supply Over Time		
	Existing (MW)	Near-Term (MW)	Longer-Term (MW)
Region Peak Load	**2,187**	**2,264**	**2,600**
Coal-to-gas	550	395	0
Cogeneration	1,223	654	112
Cogeneration with CCUS retrofit	0	553	1,068
Hydrogen-fired cogeneration	0	0	93
Combined-cycle	900	0	0
Combined-cycle with CCUS retrofit	0	840	840
Simple-cycle	47	47	279
Hydrogen-fired simple-cycle retrofit	0	0	0
Hydroelectric	485	485	485
Nuclear SMR	0	0	0
Wind	1,334	1,734	1,902
Solar[16]	247	623	1,023
Other	50	50	50
Storage	88	211	100
Total Generation Capacity	**4,924**	**5,592**	**5,952**

[16] This figure does not include rooftop solar, which is considered within 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 500 kV HVDC lines also pass through the Central region.

The Hanna area is served by a 240 kV loop which also provides transmission access for generators. The 240 kV system extends west to the Brazeau hydro station and to Bickerdike in the northwest, where the recently connected 900 MW Cascade combined-cycle generator is located.

The Cold Lake area is served by a double-circuit 240 kV line and a local 144 kV system supporting oil sands and industrial operations. Local area load is supplied by a looped 138 kV and 144 kV system that extends throughout the Central region.

TRANSMISSION PROJECT STATUS

The CETO project is now under construction with an anticipated in-service date of Q2 2026

- Upon the first milestone being met in November 2022, the AESO provided direction to the TFOs on December 1, 2022, to start CETO Stage 1 construction
- Based on results of the next reaffirmation study conducted in January 2024, the AESO provided direction to the TFOs on February 20, 2024, to start CETO Stage 2
- The planned conductor for CETO was changed to high-temperature conductor, adding more capacity to CETO to provide additional flexibility to integrate further generation in Central East sub-region

The PENV NID application was approved by the AUC in April 2019

- The AESO anticipates the existing system can accommodate additional renewables generation before PENV is needed

Opportunity to Connect New Generation and Congestion Risk[17]

- Central East is the geographical area east of Red Deer from Hanna to Lloydminster
  - Like the South planning region, it has been attractive to generation developers for its wind and solar potential
  - The generator integration capability of this sub-region had been limited by the transfer-out capability provided by 912L/9L20 from Battle River to Red Deer, and several 138 kV and 144 kV lines
  - The now under-construction CETO project, a double-circuit 240 kV transmission line between Battle River and Red Deer, is anticipated to mitigate near-term transfer-out constraints, reduce operational complexity (eliminating complex RAS) and facilitate generation development into the future
- The Southeast and Central East regions are connected by various 240 kV and 138/144 kV lines
  - With the large number of renewable projects connecting in the Southeast, there is potential for congestion on these lines, as a portion of the excess generation from the region may flow north in addition to the Cassils/Newell–Milo–Langdon path to Calgary

Near-Term Transmission Plans

The near-term need of the region is expected to be met by CETO, no other plans are identified.

Increasing Operational Complexity

- Forecasts anticipate the retirement of the Battle River and Sheerness coal-to-gas units in the near- and mid-term. The retirement of Battle River units will reduce operational flexibility in controlling system voltages
  - High voltage issues may present themselves under concurrent outages and/or contingencies
- Operational measures are technically effective; however, aggregated mitigations are needed under various scenarios, which increases operational complexity
  - The AESO will continue to monitor the situation and will add voltage support if required

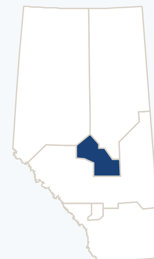
Longer-Term Transmission Plans

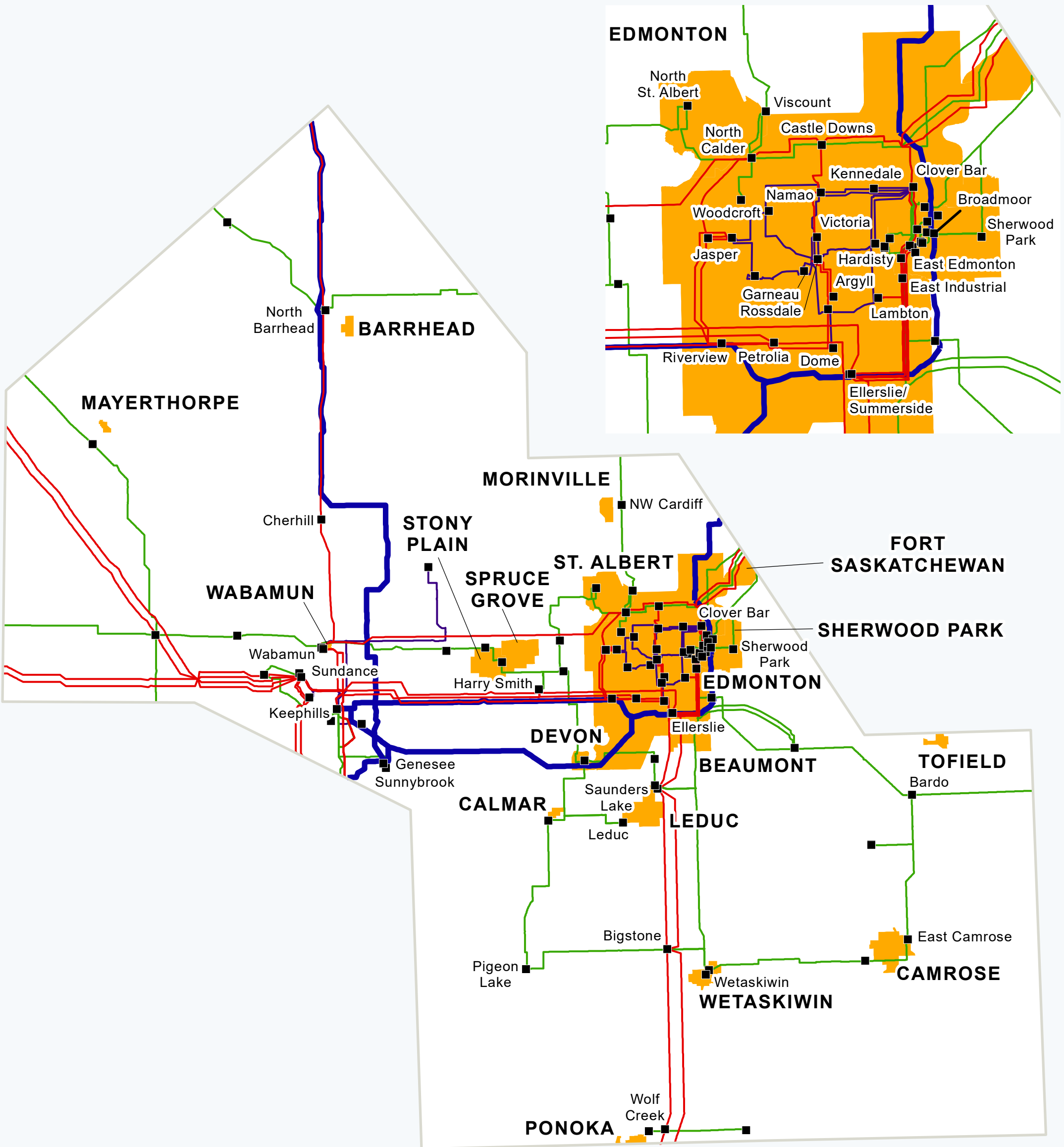
The Central planning region is well-positioned for load and generation growth with no major longer-term transmission developments required beyond CETO.

[17] Previously, the LTP included comprehensive information on the province's transmission system capability and congestion risk. This data is now available through separate AESO products, the Transmission Capability Map and Cluster Assessment Reporting.

Edmonton Planning Region

FIGURE 7: Edmonton Planning Region





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

View SLDs: aeso.ca/grid/LTP

Overview and Forecast

Load Characteristics

- **2,198 MW** regional peak
  - Consists of residential, commercial, oil refining, manufacturing and pipelines
- Reference Case forecasts a peak load growth rate of **1.9 per cent** annually over the 20-year planning timeframe

Generation Characteristics

- **3,348 MW** installed capacity
  - Mainly coal-to-gas and combined-cycle units
- Coal-to-gas generation is expected to begin retiring between 2024 and 2029, resulting in a net loss of generation capacity in this region
- Near-term forecast includes some combined-cycle with CCUS retrofits and minor solar additions
- The longer-term forecast includes additional CCUS retrofits and some hydrogen-fired cogeneration and storage additions

TABLE 18: Edmonton Planning Region Load and Generation Capacity Forecast

Load/Supply	Change in Load/Supply Over Time		
	Existing (MW)	Near-Term (MW)	Longer-Term (MW)
Region Peak Load	**2,198**	**2,178**	**3,155**
Coal-to-gas	1,725	929	0
Cogeneration	92	92	49
Cogeneration with CCUS retrofit	0	0	39
Hydrogen-fired cogeneration	0	186	186
Combined-cycle	1,136	568	418
Combined-cycle with CCUS retrofit	0	568	1,136
Simple-cycle	270	222	454
Hydrogen-fired simple-cycle retrofit	0	0	0
Hydroelectric	0	0	0
Nuclear SMR	0	0	0
Wind	0	0	0
Solar[18]	32	232	382
Other	0	0	0
Storage	0	0	50
Total Generation Capacity	**3,348**	**2,704**	**2,715**

[18] This figure does not include rooftop solar, which is considered within the load forecast.

Existing Transmission System

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

Local load in this region is served by a transmission system consisting of 500 kV, 240 kV, 138 kV and 69/72 kV lines:

- A 500 kV loop between the Wabamun Lake area and Edmonton feeds power from gas-fired generating plants in the Wabamun Lake area to the southeast corner of the City of Edmonton
  - The loop also extends to the Heartland substation in the Northeast Planning Region
- A 240 kV system connects surrounding regions to load pockets in Edmonton and within city limits
- A 138 kV system feeds load in the areas outside of the city and the heavy industrial area to the east
- A 72 kV system is dedicated to serving load within the city

TRANSMISSION PROJECT STATUS

The CETR NID Application was filed with the AUC in December 2023 and approved in September 2024

- The development is expected to be in service by 2027, subject to TFO facility application approval

Opportunity to Connect New Generation and Congestion Risk[19]

- The Wabamun Lake area, situated to the west of Edmonton, serves as a key power generation hub for Alberta
  - It has historically accounted for a significant portion of the province's baseload electricity capacity
- With several generators anticipated to be retired or mothballed in the near and longer term, the Sundance, Genesee and Keephills sites are well-positioned to accommodate the integration of new-generation capacity

[19] Previously, the LTP included comprehensive information on the province's transmission system capability and congestion risk. This data is now available through separate AESO resources, the Transmission Capability Map and Cluster Assessment Reporting.

Near-Term Transmission Plans

City of Edmonton

- Planning studies anticipate the capacity to serve load at Kennedale and Namao will become insufficient in contingency conditions and a longer-term solution is needed to serve load reliably
  - Additionally, the 72 kV system serving the city has several aging, oil-filled cables and is becoming constrained due to growing load
- The recently approved CETR project combines serving growing load with the need to decommission end-of-life assets, thereby optimizing costs
- This project also provides the provision for future 240 kV development in the city, providing a solution when other 72 kV cables reach end-of-life and helping reduce short-circuit levels in the area

Wetaskiwin Area

- Overloads were also observed on the 138 kV transmission line from Bigstone to Pigeon Lake
- Line rating increases can address these overloads
  - Underbuild removal is a potential option to mitigate line clearance limitations
- The AESO will work with the TFO to determine the optimal solution

Fort Saskatchewan to Edmonton

- Overloads were also observed on several 138 kV transmission lines outside the City of Edmonton
- Line rating increases can address these overloads, and the AESO will work with the TFO to determine the optimal solution

TABLE 19: Summary of Near-Term Plans (Next 5 Years)

Description	Primary Driver(s)
City of Edmonton	
Build a new 240/72 kV substation called Fort Road Cut into 915L (Clover Bar–East Edmonton 38S) and bring two 240 kV lines into Fort Road Decommission the Kennedale substation and the cables between Clover Bar, Kennedale, and Namao Redistribute load from Kennedale to Fort Road Add two 72 kV lines from Fort Road to Namao	■ Load growth ■ Replace aging infrastructure
Wetaskiwin Area	
Increase line rating for 805L from Bigstone 86S to Pigeon Lake 964S	■ Load growth
Fort Saskatchewan to Edmonton	
Increase line rating for 694L from Fort Saskatchewan 33S to Westwood 422S Increase line rating for 700L from Westwood 422S to Sherwood Park 746S Increase line rating for 731L from Broadmoor to East Edmonton 38S	■ Load growth

Longer-Term Transmission Plans

City of Edmonton

- Significant load growth is expected in the Edmonton region over the longer term, mainly driven by higher adoption of EVs and the electrification of heating and cooling systems, particularly within the City of Edmonton
- Transmission developments are required to mitigate anticipated load-serving issues. In addition, transmission infrastructure serving the city includes many underground 72 kV cables that are expected to reach end-of-life in the coming years. We plan to coordinate with the TFO to develop optimized plans to address both the load-serving and asset condition needs. Needs include:
  - A new 240 kV line is proposed between the new Fort Road substation (to be built under the CETR project) and the Victoria substation
    - This line will allow for the decommissioning of the 72kV lines between Rossdale and Victoria and reduce high short-circuit levels in the area
  - The two 72 kV lines between Clover Bar and Hardisty are also proposed to be decommissioned and replaced with a new 72 kV single line between Hardisty and East Industrial, supplying Hardisty through it and the existing line
  - The 72RG1 line between Rossdale and Garneau should also be replaced to address the Garneau substation's load and aging condition in the coming years
  - Load at Woodcroft is also anticipated to increase and drive loading on 72PM25, 72JM18 and 72JW19
    - To mitigate concerns on these lines, the Woodcroft substation must be reconfigured and its normally open point moved
  - 72RW3 either needs to be upgraded or 72NW15 and 72VN21 need to be tied together and used to parallel the existing 72RW3 line in the long term

KEG Loop

- In the KEG loop, voltage levels are observed to increase when traditional thermal generation dispatches in the region are low
  - This occurs when renewables generation is high
  - The situation will continue to be monitored and a reactor will be considered if required

Bulk System

- The potential for SMRs in the Northeast and Northwest regions, along with the growth of renewables in the Central and South regions, has impacts on the bulk Edmonton transmission system:
  - If generation growth in the Northeast region materializes, an increased flow is expected on some 138 kV paths from Athabasca to Edmonton
    - The Fort McMurray East development will support the 138 kV path
  - If generation growth to the west of the Edmonton region materializes, an increased flow is expected on some 138 kV and 240 kV paths that transfer power from west to east
    - Increased flows can be managed by adjusting the PST at Keephills
  - If renewables generation continues to grow, flow is expected to increase on the 240 kV lines connecting Ellerslie to the west
    - Increased flows can be managed by adjusting the PST at Keephills

TABLE 20: Summary of Longer-Term Plans (6–20 Years)

Description	Primary Driver(s)
City of Edmonton	
Add a 240 kV line between Fort Road (to be built under CETR) and Victoria and decommission the three RV cables between Rossdale and Victoria Add a 72 kV line between Hardisty and East Industrial Decommission the two CH cables between Clover Bar and Hardisty Increase line rating for 72RG1 between Rossdale and Garneau Reconfigure the normally open point within Woodcroft substation Increase line rating for 72RW3 between Rossdale and Woodcroft or tie 72VN21 and 72NW15 together to create a new line between Victoria and Woodcroft	■ Load growth ■ Replace aging infrastructure

Calgary Planning Region

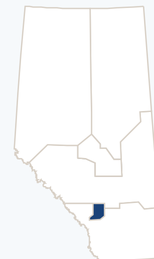
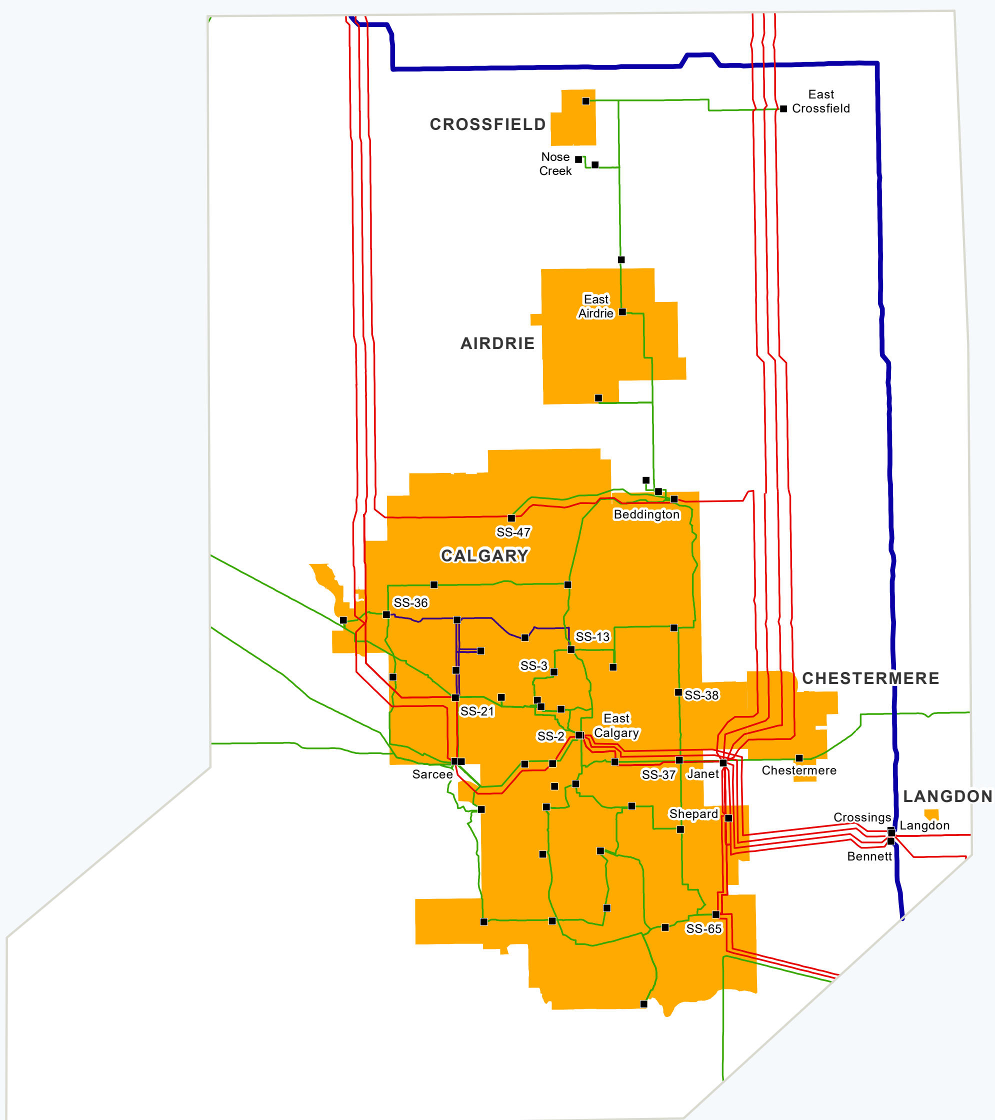


FIGURE 8: Calgary Planning Region



Legend

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

View SLDs: aeso.ca/grid/LTP

Overview and Forecast

Load Characteristics

- **1,936 MW** regional peak
  - Primarily urban, including significant residential and commercial demand, as well as some industrial load
- Reference Case forecasts a peak load growth rate of **2.56 per cent** annually over the 20-year planning timeframe

Generation Characteristics

- **1,650 MW** installed capacity
- Expects most combined-cycle units to retrofit with CCUS, resulting in a decrease in total capacity due to parasitic load from CCUS

TABLE 21: Calgary Planning Region Load and Generation Capacity Forecast

Load/Supply	Change in Load/Supply Over Time		
	Existing (MW)	Near-Term (MW)	Longer-Term (MW)
Region Peak Load	**1,936**	**1,939**	**3,116**
Coal-to-gas	0	0	0
Cogeneration	29	29	29
Cogeneration with CCUS retrofit	0	0	0
Hydrogen-fired cogeneration	0	0	0
Combined-cycle	1,318	120	0
Combined-cycle with CCUS retrofit	0	1,079	1,079
Simple-cycle	144	144	144
Hydrogen-fired simple-cycle retrofit	0	0	0
Hydroelectric	0	0	0
Nuclear SMR	0	0	0
Wind	0	0	0
Solar[20]	139	139	189
Other	10	10	10
Storage	10	10	0
Total Generation Capacity	**1,650**	**1,531**	**1,451**

[20] This figure does not include rooftop solar, which is considered within the load forecast.

Existing Transmission System

Calgary is a major hub in the transmission system. 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 system 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 AB–BC intertie connects to the system at Langdon, approximately 10 kilometres east of the city.

TRANSMISSION PROJECT STATUS

Currently, no major projects are approved or under construction in the Calgary Planning Region

Opportunity to Connect New Generation and Congestion Risk[21]

Inflow conditions primarily drive constraints in the Calgary region. Therefore, new generation within the region is ideal.

Near-Term Transmission Plans

No plans are identified in the near-term.

Bulk System

- As renewables development increases south of Calgary, generation power flows north, impacting the Calgary region's power flow pattern
  - This power flow pattern change can further stress the 240 kV backbone system and some of the 138 kV transmission lines that parallel the north-south 240 kV system in the Calgary region
- The Southwest Area Transmission Development (SWATD) discussed in the **South Planning Region Near-Term Transmission Plans section** is expected to meet these needs in the near term
  - Additional reinforcement may be needed in the longer term to help manage the change in flow patterns due to load growth and the evolving generation mix within the province

Longer-Term Transmission Plans

Significant load growth is expected in the Calgary region over the longer term, mainly driven by higher adoption of EVs and the electrification of heating and cooling systems. Development around the City of Calgary and City of Airdrie areas is required to address transfer-in and load-serving capability.

City of Calgary Area

- Thermal overloads were observed on the 240 kV path from SS-65 to SS-25 under transmission contingency
  - Line rating increases can address these overloads
  - The AESO will work with the TFO to determine the optimal solution
- Additional transformation capacity at key 240 kV transfer in substations (Sarcee, Janet, East Calgary, Beddington, SS-65) may be required
  - If one of the paired transformers is out of service, the other may become overloaded
  - Replacing existing transformers with higher capacity units is a potential option
- Thermal overloads were observed on the 138 kV path from Janet to SS-38 under transmission continency
  - Line rating increases can address these overloads
    - Current transformer (CT) replacement can remove line rating limitations
  - The AESO will work with the TFO to determine the optimal solution

[21] Previously, the LTP included comprehensive information on the province's transmission system capability and congestion risk. This data is now available through separate AESO products, the Transmission Capability Map and Cluster Assessment Reporting.

- Thermal violations were observed on the 138 kV system within city limits under system normal and/or under transmission contingency
  - The ENMAX Distribution Driven Transmission Project (DDTP) is a potential solution to mitigate these violations on top of non-wire solutions.
- Thermal violations were observed on the 69 kV system under the loss of transformers at SS-21
  - DDTP can address these violations.
- Low voltages were observed in the Calgary area under system normal and various transmission contingencies
  - Voltage support (such as capacitor banks) may be required during scenarios with low internal generation within Calgary and high renewables from the South

City of Airdrie Area

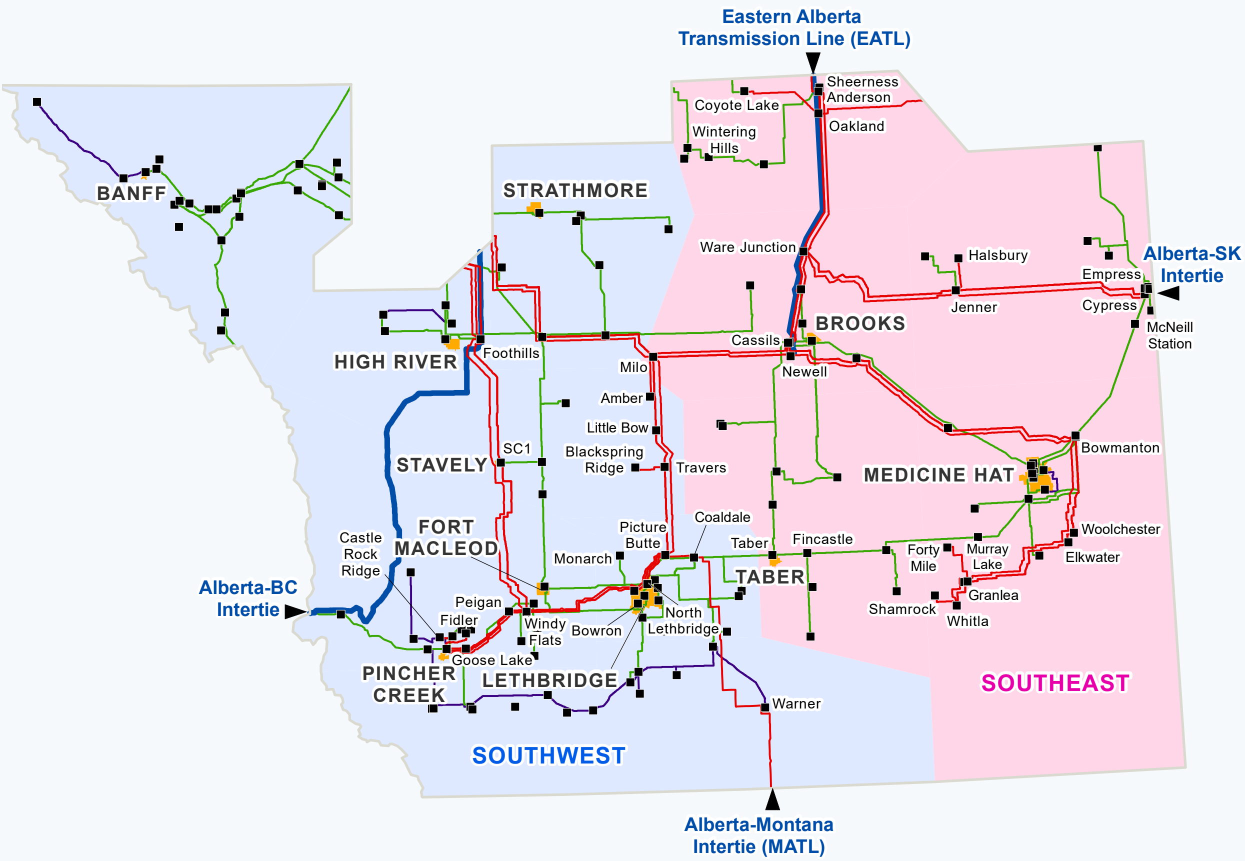
- Overloading of the 138 kV system in Airdrie may occur due to the loss of the connection to either Beddington or East Crossfield. Plans to resolve these overloads include:
  - Reconfiguring the existing 240 kV transmission line 901L to terminate in-and-out at East Crossfield
  - Adding a second system transformer at East Crossfield
  - Reinforcing the existing 138 kV system, creating an additional transmission corridor into the Airdrie area, initially built to 240 kV but may be initially operated at 138 kV

TABLE 22: Summary of Longer-Term Plans (6–20 Years)

Description	Primary Driver(s)
City of Calgary Area	
Increase line ratings for 240 kV lines 1080L and 1109L (SS-65 – SS25) Replace Sarcee 42S, Janet 74S, East Calgary 5S, Beddington 162S and Substation #65 SS-65, 240/138 kV transformers with higher capacity units (ENMAX DDTP) – New 138 kV line between Substation #36 (SS-36) and Substation #47 (SS-47) Increase line ratings for 138 kV lines 37.82L and 37.81L Voltage support device at Beddington 162S Voltage support device at East Calgary 5S	■ Load growth
City of Airdrie Area	
Reconfigure 901L/901AL (Red Deer 63S – East Crossfield 64S – Janet 74S) to be in-and-out at East Crossfield 64S Add second 240/138 kV transformer at East Crossfield 64S Upgrade Nose Creek 284S and East Airdrie 199S to 240 kV Build new 240 kV line between East Crossfield 64S, Nose Creek 284S, East Airdrie 199S and Beddington 162S	■ Load growth

South Planning Region

FIGURE 9: South Planning Region



Legend

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

View SLDs: aeso.ca/grid/LTP

Overview and Forecast

Load Characteristics

- **1,558 MW** regional peak
  - Mostly farming demand and some industrial load including pipelines, manufacturing and natural gas processing
- Reference Case forecasts an average peak load growth rate of **1.3 per cent** annually over the 20-year planning timeframe

Generation Characteristics

- **8,787 MW** installed capacity
  - Primarily wind and solar
- Renewables and storage are expected to continue to grow, with more than **1,400 MW** of wind, **1,750 MW** of solar and **550 MW** of storage developing over the 20-year forecast

TABLE 23: South Planning Region Load and Generation Capacity Forecast

Load/Supply	Change in Load/Supply Over Time		
	Existing (MW)	Near-Term (MW)	Longer-Term (MW)
Region Peak Load	**1,558**	**1,627**	**1,985**
Coal-to-gas	800	400	0
Cogeneration	146	146	5
Cogeneration with CCUS retrofit	0	0	127
Hydrogen-fired cogeneration	0	0	47
Combined-cycle	242	242	122
Combined-cycle with CCUS retrofit	0	0	0
Simple-cycle	261	261	281
Hydrogen-fired simple-cycle retrofit	0	0	0
Hydroelectric	409	409	409
Nuclear SMR	0	0	0
Wind	4,328	4,928	5,090
Solar[22]	2,392	3,512	4,297
Other	42	42	42
Storage	167	367	350
Total Generation Capacity	**8,787**	**10,307**	**10,769**

[22] This figure does not include rooftop solar, which is considered within the load forecast.

Existing Transmission System

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

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–Bowmanton–Whitla path (CBW path) and an underlying 138 kV system that connects 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, a 500 kV HVDC line.

The Southwest sub-region is the geographical area west of Lethbridge. The Southwest system comprises a broad 240-kV collector system that spans the region, collecting and providing transmission system access to generation sources as well as facilitating an intertie with Montana, USA. The Cassils/Newell–Milo–Langdon path transfers excess power from both the southwest and southeast to Calgary. The Windy Flats to Calgary path transfers excess power from the southwest to Calgary.

TRANSMISSION PROJECT STATUS

The Bowmanton Voltage Support (BVS) project was approved through the Abbreviated Needs Approval Process (ANAP) in April 2023

- The project was energized in January 2025

The VATD NID and application for exemption under Section 15(2) of the T-Reg was approved in September 2023

- The anticipated in-service date is March 2025

Timing for the CRPC project will depend on the pace of generation developments in the Southwest

Opportunity to Connect New Generation and Congestion Risk[23]

Developers are drawn to the South region for its strong wind and solar resources. This is reflected in the number of wind and solar generator connection requests in the AESO's project list. The region is already subject to significant congestion, which is anticipated to increase with the energization of additional intermittent generation.

Southeast

- Several potential reliability issues, including voltage, transient stability, and the risk of a double-circuit contingency, limit the generation integration capability on the CBW path
- The AESO is exploring potential solutions to ensure system strength is adequate to support the reliable operation and integration of generation in the area

Southwest

- In the near-term, the Cassils/Newell–Milo–Langdon path will be congested and will limit the generation integration capability of the region

138 kV System

- Some localized congestion risk is expected on 138 kV transmission lines near generating units

Near-Term Transmission Plans

Lethbridge Area

- Thermal overloads and voltage violations are anticipated on the 138 kV system serving load in and around the City of Lethbridge under transmission contingency conditions
- A new 240 kV source west of the City of Lethbridge connecting to the 138 kV system via the Bowron substation is a potential plan
- Voltage support (such as capacitor banks) at the Monarch substation may be required

Southeast

- The Southeast Transmission Development (SETD) plan enables additional generation capacity integration in the sub-region
- The plan includes the development of a new double-circuit 240 kV line connecting Whitla to Newell, forming a loop system from the existing CBW path
- The plan will mitigate existing and future voltage violations and thermal overloading in contingency conditions
  - It will also address the risks of loss of generation for extreme events such as loss of double-circuit transmission lines

[23] Previously, the LTP included comprehensive information on the province's transmission system capability and congestion risk. This data is now available through separate AESO products, the Transmission Capability Map and Cluster Assessment Reporting.

System Strength

In October 2023, voltage oscillations were observed on the Alberta Interconnected Electric System (AIES) in the City of Medicine Hat and along the CBW path.

These oscillations coincided with transmission line outages and were attributed to generator control instability due to weak system strength.

Generator control system tuning, synchronous condenser and grid-forming BESS are being evaluated as a potential approach to strengthening the system.

Southwest

- The SWATD plan supports renewables generation development in the whole South planning region
- The potential plan includes the development of a double-circuit line from Newell to Milo to Calgary—both 500 kV and 240 kV options are being considered for the Newell to Calgary path.
  - Currently, the 500 kV option is the leading alternative, with similar environmental and land impact and higher transfer capability
  - The termination point of the transmission development near Calgary (Langdon or Foothills) will depend on the location of future generation and load additions in the area
- A double-circuit 240 kV line from SS-65 to Sarcee substation is required to reinforce the existing 240 kV system just south of Calgary

Sheerness Area

- Thermal overloads were observed on the 138 kV system west of Coyote Lake
- A new 138 kV line between Coyote Lake and Wintering Hills is a potential plan

Empress Area

- Thermal overloads were observed on the 138 kV transmission line from Chappice Lake to Cypress
- Line rating increases can address these overloads

Lethbridge/Vauxhall Area

- Thermal overloads were observed on the 138 kV transmission line from Taber to Coaldale
- Line rating increases can address these overloads

TABLE 24: Summary of Near-Term Plans (Next 5 Years)

Description	Primary Driver(s)
Lethbridge Area	
Build new 240/138 kV substation connected to the 240 kV transmission lines between North Lethbridge 370S and Windy Flats 138S Add a new 138 kV line from the new substation to Bowron 674S Voltage support device at Monarch 492S	■ Load growth
Southeast	
New double-circuit 240 kV line from Whitla 251S to Newell 2075S Voltage support device at Whitla 251S	■ Mitigate congestion
Southwest	
New double-circuit 500 kV line from Newell 2075S to Milo 356S to Langdon 102S New double-circuit 240 kV line from ENMAX SS-65 to Sarcee 42S	■ Mitigate congestion
Sheerness Area	
Add new 138 kV line from 804S Wintering Hills to 963S Coyote Lake	■ Mitigate congestion
Empress Area	
Increase line rating for 658L (658L Tap to Cypress 562S)	■ Mitigate congestion
Lethbridge/Vauxhall Area	
Increase line rating for 172L (172L Tap to Coaldale 254S)	■ Mitigate congestion

Longer-Term Transmission Plans

- The Southeast and Southwest plans are significant infrastructure developments that would add substantial transmission capacity to address existing congestion and facilitate additional generation connections
- If generation connections in the southeast exceed the forecast from the 2024 LTO, the proposed Southeast plan can be upgraded with series compensation to facilitate the integration of additional generation
- If additional generation connections develop in the southwest, then CRPC can provide additional transmission capacity mitigating potential future congestion
  - CRPC also has the additional benefit of supporting the AB–BC intertie

TABLE 25: Summary of Longer-Term Plans (6–20 Years)

Description	Primary Driver(s)
Southwest	
Build a new 500/240 kV substation (Chapel Rock) connected to the AB–BC intertie New 240 kV line from the new substation to a substation in the Pincher Creek area Add voltage support device (capacitor bank and/or static VAR compensator [SVC]) in the Pincher Creek area	■ Mitigate congestion

Planning Alberta's Interties

Our intertie plans are aligned with directions issued by the GOA, which include:

- Restoring the AB–BC intertie to or near to 950 MW
- Procuring and maintain high levels of ancillary services to support full import flows on the AB–BC intertie and the MATL
- Increasing the path rating of the AB–SK intertie as part of the McNeill converter's end-of-life replacement

Near-Term Intertie Plans

AB–BC Intertie Restoration

The existing AB–BC intertie has an import capability of 800 MW, while the import path rating of this intertie is approximately 1,200 MW.

The AESO has developed a restoration plan for the AB–BC intertie, with the goal of restoring the import capability of this intertie to or near to 1,200 MW. This restoration plan can be described in three steps:

Step One

- Increase FFR to enable scheduling the BC and MATL[24] interties close to their existing import capability
- AESO has procured approximately 600 MW of FFR for 2025 to 2027 and additional FFR is our primary plan to meet the GOA directive

Step Two

- Increase import capability of the AB–BC intertie to approximately 950 MW by implementing the AIR plan
  - Upgrade the 500/240 kV transformer at Bennett Substation, which is nearing end-of-life
  - Series compensation is needed to improve voltage performance and loadability on the 500 kV 1201L
  - Line clearance issue mitigation work is required to improve the thermal rating of the existing 1201L
- 150 MW of additional FFR will be required once the AIR project is in service

Step Three

- Increase import capability of the AB–BC intertie to approximately 1,200 MW by implementing the CRPC plan
  - Timing to trigger the CRPC plan will depend on the pace of generation developments in the southwest
- 250 MW of additional FFR will be required once the CRPC project is in service so that the AB–BC and MATL interties can be scheduled up to the full import flows

[24] The existing import capability of MATL is 310 MW.

McNeill Replacement

- The McNeill converter is expected to reach its end-of-life in the next 10 years
- The AESO is:
  - Developing a plan focusing on the size, location, technology, and control capabilities of a replacement converter for the AB–SK intertie
  - Working with SaskPower to perform planning assessments for the replacement converter to determine an appropriate size to maximize the use of existing transmission infrastructure

TABLE 26: Summary of Near-Term Intertie Plans (Next 5 Years)

Intertie	Description
AB–BC	Upgrade the 500/240 kV transformer at Bennett 520S Add series compensation to the 500 kV AB–BC intertie line 1201L
AB–SK	Converter replacement and expansion

Longer-Term Intertie Plans

MATL

A new HVDC back-to-back (B2B) located near Picture Butte is a potential option to restore the AB–BC intertie; however, the AESO plans to use FFR as its primary approach.

TABLE 27: Summary of Longer-Term Intertie Plans (6–20 Years)

Intertie	Description
MATL	New HVDC B2B converter located at or near the Picture Butte substation

Longer-Term Transmission Plans for Alternative Scenarios

The AESO investigated additional scenarios to evaluate impacts of the pace and extent of electrification, new generation technologies, increased intertie connections and CER

Decarbonization by 2035

The Decarbonization by 2035 scenario includes the addition of the federal CER, as provided in the Canada Gazette 1, to assess the impact of accelerated decarbonization schedules.[25]

In the near term, transmission needs align with those identified in the Reference Case. Earlier retirements of large-capacity thermal assets combined with more restrictions on any new emitting assets after 2035 are expected in this scenario.

We anticipate new replacement baseload generation facilities (e.g. hydrogen-fired, simple and combined-cycle with CCUS) will take advantage of existing transmission capability vacated by retired facilities. With a changing resource mix, generation-driven transmission plans may be accelerated.

Alternative Decarbonization

The Alternative Decarbonization scenario investigates the expansion of intertie connections with neighbouring jurisdictions. It projects the same load as the Reference Case, with greater reliance on wind and solar, and increased exchanges with our neighbours through enhanced intertie capabilities.

AB–BC intertie restoration plans, as well as the McNeill conversion and expansion, are aligned with this scenario.

New Intertie Opportunities

AB–BC

In the 2017 LTP, the AESO investigated a new transmission line development between Alberta and British Columbia. With a second large intertie to British Columbia, the total effective transfer capability could be increased following restoration.

Two candidates for the location of a new intertie between Alberta and British Columbia were assessed: a northern route and a southern route. The northern route would connect the Wesley Creek substation in northwestern Alberta with the substation at the Site C hydrogeneration project on the Peace River in northern British Columbia. The southern route would parallel the existing intertie from the proposed Chapel Rock substation in southwestern Alberta to a substation in Cranbrook, British Columbia.

Each option requires system reinforcements in British Columbia and/or Alberta in addition to the intertie itself.

Northern Intertie

The initial results with the northern intertie connected into the Wesley Creek substation showed that a new 500 kV line from the Wesley Creek substation to the Livock substation and series compensation on the planned lines may be required.

[25] The AESO's LTO was published on May 15, 2024, between the releases of Canada Gazette 1 and Gazette 2.

Southern Intertie

In the southern intertie cases, the Chapel Rock Transmission Development, including two 240 kV lines from the Chapel Rock substation to the Pincher Creek area, was assumed to be in place. The southern intertie did not result in any major overloads, and thus, no enhancements were recommended for this option.

AB–SK

Three potential locations—Fort McMurray, Lloydminster and Hanna—have been identified for new intertie opportunities between Alberta and Saskatchewan.

High Electrification

The AESO incorporated a High Electrification scenario to investigate the impacts of accelerated residential, commercial and industrial electrification compared to the Reference Case. Increased load throughout the forecast results in the largest capacity build-out of all scenarios, including 900 MW of additional SMR.

North

Completing the Bickerdike to Little Smoky 240 kV line discussed in the **Northwest Planning Region Near-Term Transmission Plans section** is a potential plan to ensure reliability for increased load and generation in the area.

A portion of the SMR generation considered in this scenario is anticipated to be located in Northwest region. The 240 kV double-circuit connecting Poplar Hill to Little Smoky should be sufficient to supply load and integrate this addition, depending on siting. If located to the northeast of the sub-region region, an additional 240 kV line may be required.

In the Northeast region, the Fort McMurray East 500 kV transmission line is sufficient to support the modelled generator and load additions.

Edmonton and Calgary

The resulting increase in load could drive substantial transmission development in both Edmonton and Calgary. If load grows at a rate similar to the High Electrification scenario, transmission needs identified in the Reference Case longer-term plans will begin to manifest within 10–15 years. In the longer term, additional development will be required to ensure system reliability.

TABLE 28: Anticipated Longer-Term Needs in Edmonton Planning Region Under the High Electrification Scenario

Description	Primary Driver(s)
City of Edmonton	
Add voltage support	■ Load growth
138 kV System Around the City of Edmonton	
Add voltage support Upgrade the 138 kV system connecting Edmonton to Athabasca area Upgrade the 138 kV system connecting Edmonton to Fort Saskatchewan area Upgrade the 138 kV system south of the City of Edmonton	■ Load growth
240 kV System Around the City of Edmonton	
Upgrade the 240 kV system connecting Sundance 310P to the East Upgrade the 240 kV system connecting Ellerslie 89S to the West Upgrade the 500/240 kV transformers at Ellerslie 89S	■ Load growth

TABLE 29: Anticipated Longer-Term Needs in Calgary Planning Region Under the High Electrification Scenario

Description	Primary Driver(s)
Calgary Region	
Add voltage support Increase transformation capacity on the bulk transmission system	■ Load growth
138 kV System Within the City of Calgary Area	
Add voltage support Upgrade the 138kV system paralleling the 240kV loop Upgrade the 138kV system around the city centre Upgrade the 138kV path connecting Substation #21 to the Seebe area Upgrade the 138kV paths into the city from the south	■ Load growth
240 kV System East of the City of Calgary	
Upgrade the 240kV system into Calgary from Langdon 102S	■ Load growth

Central and South

Renewables integration in the High Electrification scenario aligns with the Reference Case. In the Central region, the CETO project supports the modelled renewables generator additions, while the SETD and SWATD plans are sufficient for the South region.

New Areas of Focus

The evolution of Alberta's generation fleet to a much-increased proportion of intermittent generation has led to increased system performance and reliability challenges

Reliability Requirements

The evolution of Alberta's generation fleet to a much-increased proportion of intermittent generation has led to increased system performance and reliability challenges, including:

- Weakened frequency response (system ability to maintain and restore the balance between supply and demand by stabilizing the grid frequency after a disturbance)
- Diminished system strength (system ability to maintain stable voltages through disturbances such as faults, sudden changes in load or the loss of a generator)
- Reduced flexibility (system ability to adapt and respond to changes in electricity supply and demand in real-time)

The AESO published its plans regarding system performance and reliability in its ***Reliability Requirements Roadmap***. Transmission infrastructure development is one of several potential solutions to the grid challenges identified in the roadmap. Costs and operational characteristics of all potential solutions will be assessed prior to pursuing transmission infrastructure development.

Alternative Potential Solutions

Among other solutions, we are considering:

- FFR technologies to increase frequency stability
- Generator control tuning, synchronous condenser or grid-forming BESS to increase system strength
- New ancillary services to increase flexibility

We will publish our next *Reliability Requirements Roadmap* in 2025, providing updates on potential solutions for grid reliability.

Data Centres

In 2024, several data centre projects, representing over 8,600 MW in capacity, submitted connection applications to the AESO.

Due to the data centre projects' early stages of development and the recency of their submissions, the LTP does not include transmission plans for these potential loads.

As the data centre applications progress through our connection process, we will develop transmission plans driven by these large, discrete and localized load additions.

As we move forward with potential data centre-driven transmission plans, we will ensure reliable data center integration into the grid. To that end, we are:

- Reviewing Alberta's regulatory framework, ISO tariff and our connection process requirements
- Developing data centre study, modelling and technical requirements
- Producing a location-based load capability map
- Participating in FERC and ISO/RTO Council analyses and initiatives to assess and address the impacts of large loads on the electricity grid

Affordability

The AESO strives to maintain transmission system affordability by minimizing infrastructure costs through a combination of lower-cost transmission build alternatives and system optimizations

The AESO strives to maintain transmission system affordability by minimizing infrastructure costs through a combination of strategies, including using lower-cost transmission build alternatives to mitigate transmission congestion and optimizing the system with various advanced technologies.

Lower Cost Transmission Build Alternatives

Once we identify transmission line constraints, the AESO looks to first mitigate those constraints with high-value, low-cost solutions before proposing transmission development solutions. Such solutions can include:

- Replacing limiting substation equipment like current transformers
- Removing distribution underbuilds and resolving other line clearance issues
- Reconductoring lines to a high-capacity conductor

Optimizing the System

The AESO has investigated various technologies to optimize existing infrastructure before proposing large transmission plans, in an effort to minimize transmission costs.

Power Flow Control

In September 2022, the AESO completed a Power Flow Control (PFC) pilot project. The project demonstrated the capabilities of modular power flow controller (MPFC) technology. The MPFC was connected in series with the 138 kV transmission line 610L at Fincastle substation, located in southern Alberta near the town of Taber.

This technology is a flexible AC transmission system (FACTS) device known as a modular static synchronous series compensator (SSSC). Modular SSSCs allow the optimization (push or pull) of power flows by adjusting the reactance of a transmission line, pushing power to another line to avoid congestion.

The project tested MPFC device performance and provided integration experience that could support the technologies deployment on the AIES. The technology demonstrated its ability to perform control modes that adjust power flow on the transmission system, offering a valuable tool to help manage rapid grid changes while ensuring affordability and reliability.

Dynamic Line Rating

The AESO is currently conducting a dynamic line rating (DLR) initiative. While DLR is primarily considered an operational measure, we are open to using this technology to mitigate congestion issues.

Where we are implementing DLR:

- 144 kV transmission line 7L128 (between the Coyote Lake and Michichi Creek substations)
- 240 kV transmission lines 924L/927L (between the Milo and Langdon substations)

We will identify more opportunities to implement DLR after further studies and analyses.

Timeline:

- Initial lines target in-service date is Q2 2025

DLR Benefits:

- Reduces or defers transmission infrastructure builds
- Provides an alternative to RAS for constraint/congestion management
- Enables more renewables integration because of the correlation between wind, which drives wind generation, and wind line cooling effects

Remedial Action Schemes

RAS have been used extensively in Alberta to facilitate the transformation of the grid. RAS are automatic protection schemes designed to detect predetermined power system conditions and to automatically take corrective actions, such as tripping generation or load, to help maintain system reliability.

Currently, there are more than 60 RAS in service in Alberta, with additional RAS planned as part of in-flight connection projects. They enable more effective use of the transmission system's capabilities, helping to eliminate or defer the need for additional investments and ensuring timely project connections while maintaining system reliability.

RAS Complexity

The recent pace and scale of project additions have increased RAS complexity, potentially posing challenges to system reliability. For example, where areas have increased generation and are armed on RAS, a single contingency could trigger significant generation trips, potentially exceeding Alberta's most severe single contingency (MSSC) limit. If RAS complexity becomes unmanageable, it could necessitate transmission development to maintain grid reliability.

Non-Wires Solutions and Transmission Planning

The passage of the *Electricity Statutes (Modernizing Alberta's Electricity Grid) Amendment Act* in 2024 granted the AESO expanded authority to procure non-wires solutions, including energy storage, to address system planning needs. This enables us to propose these solutions more frequently and on a long-term basis. The amendment enhances reliability and cost efficiency by equipping us with additional tools to manage periods of high demand or transmission constraints, potentially postponing or eliminating the need for new transmission infrastructure.

Energy Storage

Energy storage, as a non-wires solution, offers valuable services and capabilities. Because of its potential, we consider energy storage an essential tool in the AESO's planning framework. We will continue to explore its diverse applications within the planning domain, guided by the regulatory framework.

Possible energy storage uses include:

- Frequency regulation
- Voltage support
- Congestion management
- System inertia support
- System strength support

An energy storage facility often has the versatility to provide several of the services listed above.

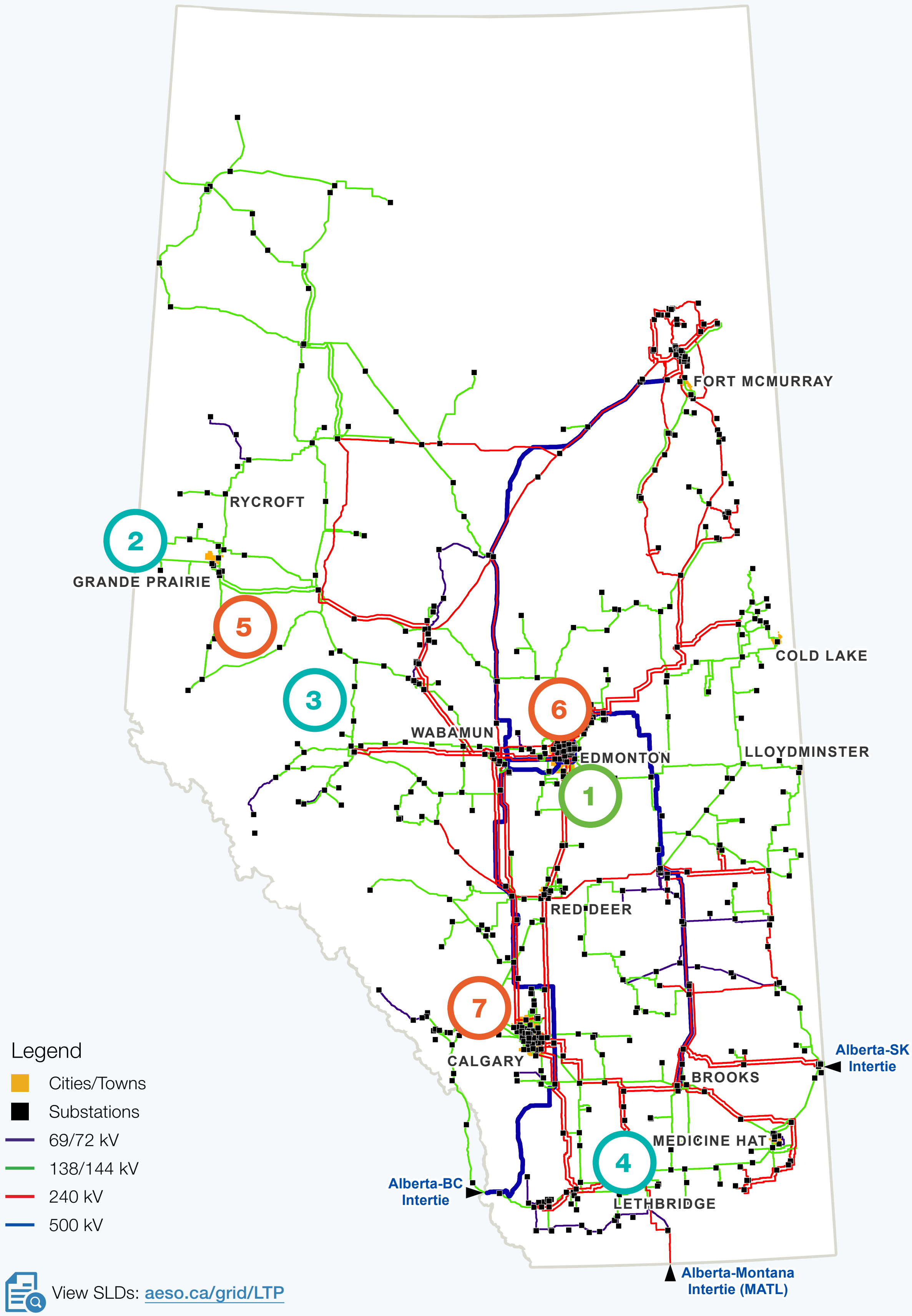
Since the inception of the *Energy Storage Roadmap*, several battery energy storage projects have come online in Alberta and more are in the project connection list.

Pursuing Supplemental Funding

The AESO is working with government and industry to identify and pursue funding grants for qualifying projects which would reduce transmission system development costs. The federal government Smart Renewables and Electrification Pathways Program (SREP) or funding opportunities through the Canada Infrastructure Bank (CIB) are examples of such programs.

Summary of Major Transmission Plans

FIGURE 10: Location of Major Load-Driven Transmission Plans



View SLDs: aeso.ca/grid/LTP

TABLE 30: Major Load-Driven Transmission Plans

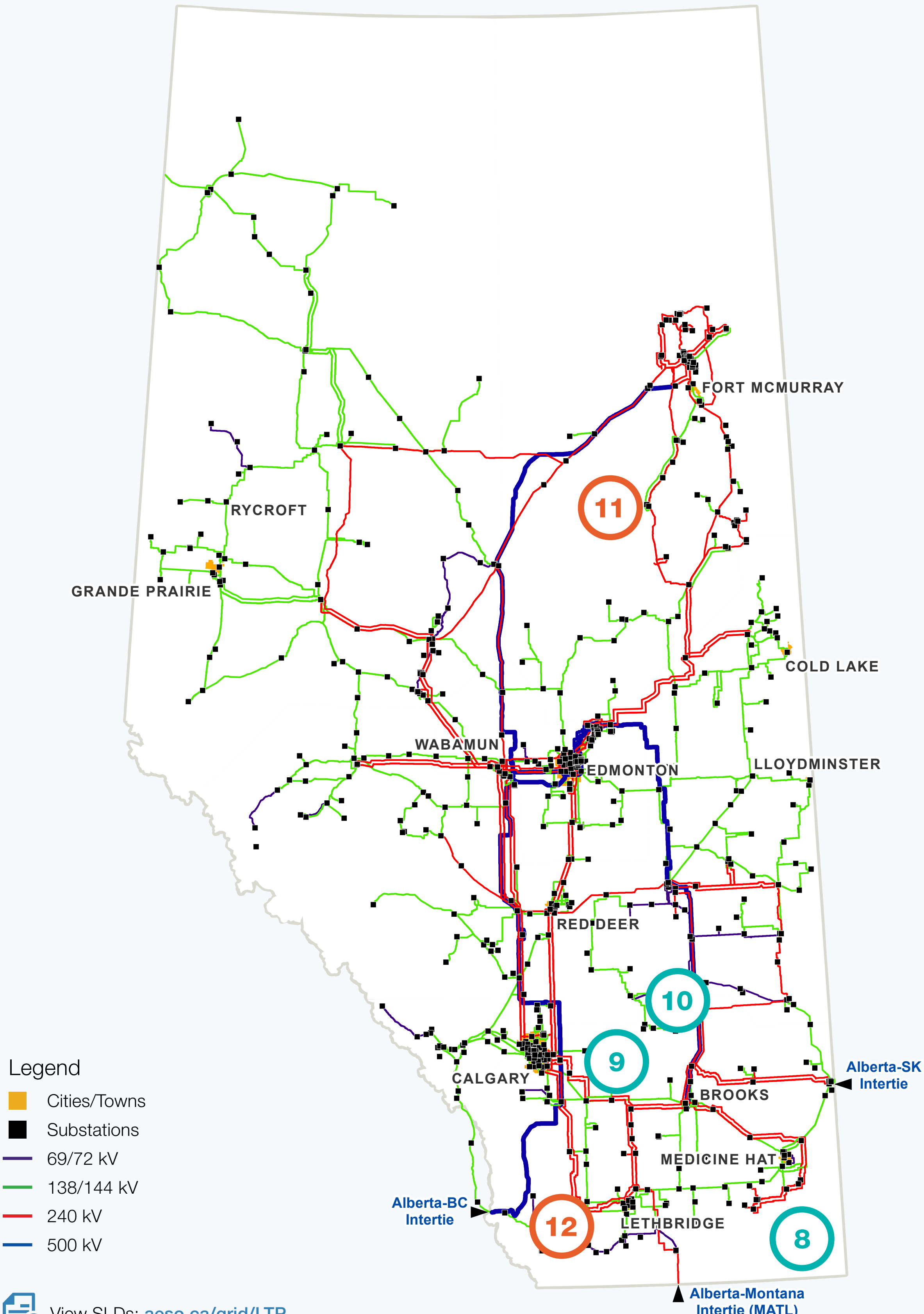
Map Ref.	Timeframe	Description	Primary Driver(s)	Cost[26] (millions)
Edmonton (in city)[27]				
1	NID Approved (Near-Term)	240 kV and 72 kV transmission developments	■ Load growth ■ Replace aging infrastructure	$280
Northwest (Grande Prairie region)				
2	Near-Term	144 kV transmission development[28]	■ Load growth	$480
Northwest (Valleyview to Fox Creek region)				
3	Near-Term	144 kV transmission development	■ Load growth ■ Manage inflow constraints	$160
South (Lethbridge region)				
4	Near-Term	240 kV and 138 kV transmission developments	■ Load growth	$45
Northwest (Grande Prairie region)				
5	Longer-Term	Second line on Northwest (Grande Prairie region) near-term development and energizing to 240 kV	■ Load growth	$260
Edmonton				
6	Longer-Term	Developments to reinforce city's 72 kV system	■ Load growth ■ Replace aging infrastructure	$70
Calgary				
7	Longer-Term	Developments to reinforce 138 kV and 240 kV systems in and around the city	■ Load growth	$470

[26] LTP cost estimates in 2025 dollars.

[27] CETR project.

[28] The AESO is considering non-wires solutions as an alternative to transmission development.

FIGURE 11: Location of Major Generation-Driven Transmission Plans



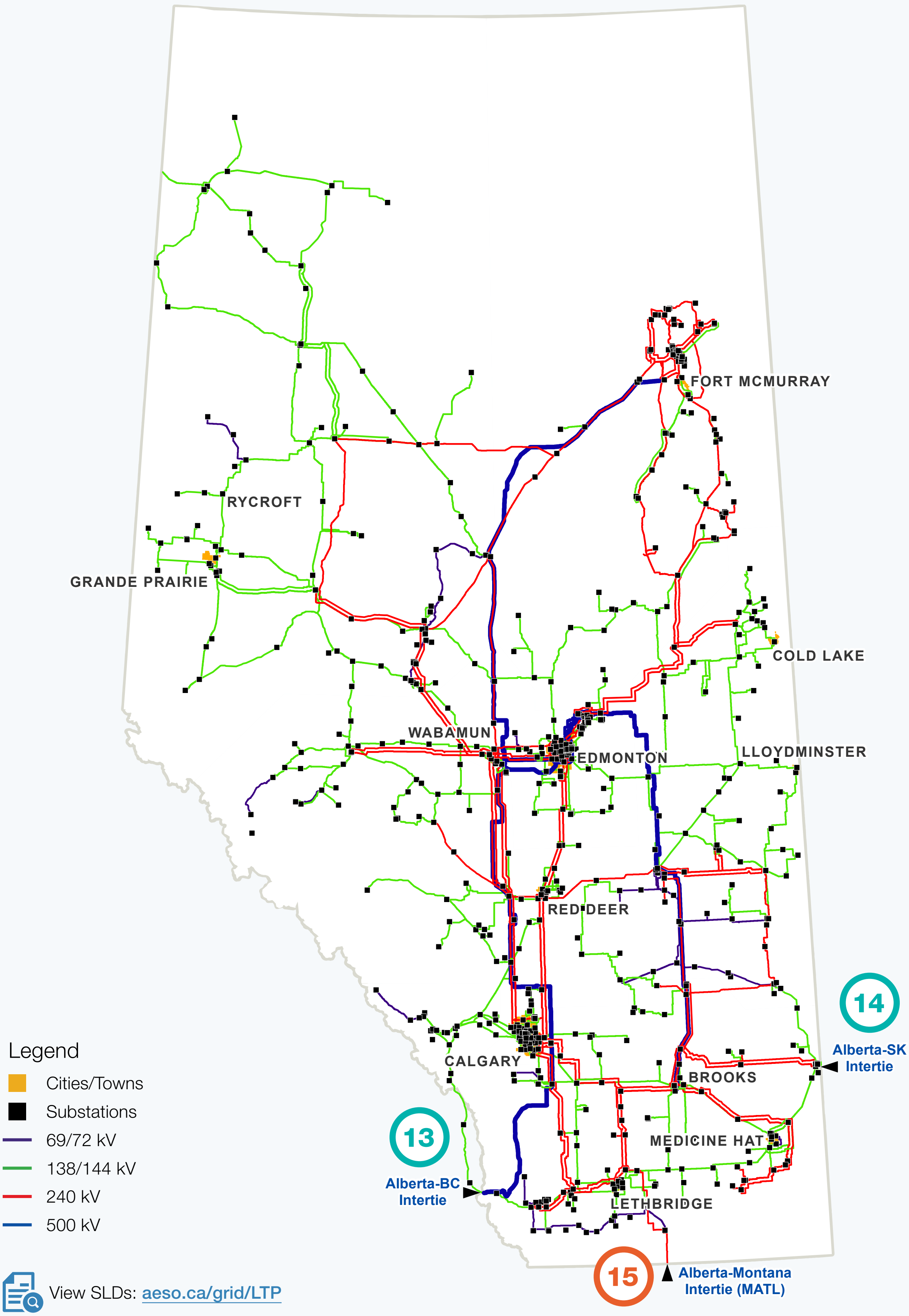
View SLDs: aeso.ca/grid/LTP

TABLE 31: Major Generation-Driven Transmission Plans

Map Ref.	Timeframe	Description	Primary Driver(s)	Cost[29] (millions)
Southeast				
8	Near-Term	New 240 kV line from Whitla to Newell and voltage support	■ Mitigate congestion	$650
Southwest				
9	Near-Term	New 500 kV line from Newell–Milo–Langdon (240 kV and 500 kV options under consideration) New 240kV line from SS-65 to Sarcee	■ Mitigate congestion	$1,850
Sheerness				
10	Near-Term	New 138 kV line from Wintering Hills to Coyote Lake	■ Mitigate congestion	$55
Northeast				
11	Longer-Term	500 kV transmission line	■ Mitigate congestion	$1,600
Southwest				
12	Longer-Term	New 500/240 kV substation, 240 kV line and SVC	■ Mitigate congestion	$450

[29] LTP cost estimates in 2025 dollars

FIGURE 12: Location of Intertie-Driven Transmission Plans



View SLDs: aeso.ca/grid/LTP

TABLE 32: Major Intertie-Driven Transmission Plans

Map Ref.	Timeframe	Description	Cost[30] (millions)
AB–BC[31]			
13	Near-Term	Upgrade transformer capacity at Bennett substation and series compensating the line	$150
AB–SK			
14	Near-Term	McNeill converter replacement and expansion	$600
MATL			
15	Longer-Term	New HVDC B2B converter[32] located at or near Picture Butte substation	N/A

[30] LTP cost estimates in 2025 dollars.

[31] AIR plan.

[32] The AESO plans to use fast frequency response to restore import capability—the B2B project is a potential alternative.

Potential Transmission Cost Impact

The impact generation-driven transmission plans will have on transmission costs will be influenced by the OTP's design

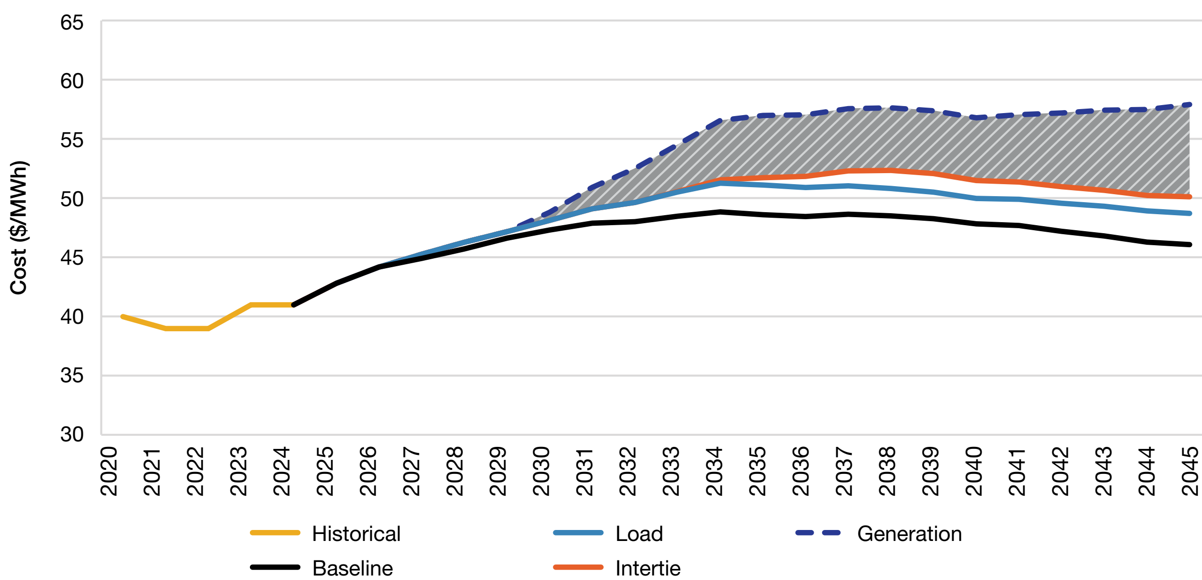
Alberta's transmission costs are made up of:

- AUC-approved transmission revenue requirements for TFOs which include returns on and of capital and system maintenance and operating costs
- Ancillary services cost
- A portion of AESO costs[33]

Figure 13 below illustrates how each type of transmission plan identified in the LTP (load-driven, generation-driven, intertie-driven) contributes to transmission costs relative to baseline costs. The baseline curve includes all AUC-approved and under-construction AESO transmission projects.

The impact generation-driven transmission plans will have on transmission costs will be influenced by the OTP's design. Under OTP, we expect some plans will proceed while others may not. As a result, generation-driven transmission plans are modelled as a range.

FIGURE 13: Transmission Cost Impact[34]



Our estimated 2025 transmission cost is $43/MWh which we expect to increase to $47/MWh by 2029. Thereafter, transmission costs will depend on OTP implementation. If all generation-driven transmission plans were to proceed to AUC-approved projects, the transmission costs could be $58/MWh by 2045.

[33] Remainder of AESO costs are allocated to the AESO trading charge.

[34] Estimated average cost per MWh of the entire transmission system (does not reflect specific ISO Tariff customer rates) – nominal dollars.

Alberta Electric System Operator

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