Methodology, Risks and Drivers

Generation Forecast Methodology

AESO 2024 Long-Term Outlook

MAY 2024

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Overview

- Generic generation capacity additions are added to the forecast iteratively by the AESO's long-term capacity expansion tool, weighing supply, demand, and expected economic returns. Retirements are determined based on an evaluation of whether an asset can effectively cover its fixed and variable costs over the remainder of the asset's life.
- Wind and solar additions are modelled with a 39 per cent and 20 per cent capacity factor, respectively. Additions are driven primarily by demand for corporate power purchase agreements (PPAs), availability of investment tax credits and grants, and the value of renewable attributes via emissions offsets or emissions performance credits.
- Oil sands cogeneration additions are evaluated exogenous to the long-term capacity expansion tool and are based on expected oil sands development. Additionally, hydrogen production facilities are anticipated to integrate hydrogen-fired cogeneration into their operations and have been included based on the forecast of hydrogen production demand.
- Both standalone batteries or hybrid batteries tied to wind and solar facilities are considered for additions in the long-term capacity expansion tool. Near-term energy storage projects that met the project inclusion criteria and projects that could participate in ancillary services as a primary revenue resource are added exogenously.
- Interties are modeled as proxy loads and generators. Each neighbouring jurisdiction had a single point load equal to the maximum export amount from Alberta, and a single generator with capacity equal to the single point load plus the total maximum import amount. Blocks and hourly price points are used for the economic operation of the proxy generators to simulate hourly intertie flows.

Project Inclusion

In the *2024 Long-Term Outlook* (LTO), the AESO has included several near-term generation projects that have reached project inclusion status in the AESO's Connection Process as of November 2023.[1] Project inclusion depends on the following criteria:

- For connection projects
  - A system access service (SAS) agreement is effective, or
  - A permit and license have been issued (if there is no SAS)
- For behind-the-fence (BTF) projects
  - A SAS agreement is effective, or
  - Generating unit owners' contribution (GUOC) has been paid (if there is no SAS), or
  - Gate 3/4 has been passed (if there is no GUOC)
- For contract change projects
  - A SAS agreement is effective.

In late 2023, we launched a new cluster study process which included amendments in the project inclusion criteria that were not reflected in the near-term forecast. For the purposes of this LTO, the AESO did not include any specific projects from the cluster study due to the uncertainty of whether the projects will move forward.

[1] https://www.aeso.ca/grid/transmission-projects/connection-project-reporting/

Asset Addition Methodology

The 2024 LTO assumes a base of existing projects and specific near-term projects that have reached the project inclusion criteria described above**.** The AESO also conducts research on potential generation capacity additions in the longer term that are expected to develop based on a number of criteria, including expectations on corporate power purchase agreements (PPA), cogeneration costs and energy storage for ancillary services. Such additional units from the research are added exogenously to the forecast before the AESO's long-term capacity expansion tool is completed.

From the baseline existing and exogenously added generators, the AESO's long-term capacity expansion simulation tool selects economic new resources to meet future electricity demand. By enabling the tool to select from a wide range of conventional, potential zero-emissions and low-emissions technologies, the tool can optimize simulated generation fleets that can most competitively recover investment costs from the market, minimizing total production costs for the generation fleet within the constraints provided to the tool.

Updates to the 2024 LTO Preliminary Update

The AESO made several adjustments to the 2024 LTO preliminary update:

- Integration of carbon capture, utilization, and storage (CCUS) on all existing large-scale cogeneration facilities. This was added exogenously based on analysis by the AESO which compared facility-specific benchmarks and associated emissions reduction schedules versus the available cost estimates of carbon capture.[2] The analysis concluded that with current federal and provincial investment credits for CCUS and with carbon emissions costs continuing as presently stated in current and proposed legislation, it would be economically favourable to install CCUS on all existing cogeneration facilities rather than incurring the costs associated with carbon dioxide emissions.
- Addition of new cogeneration facilities with additional CCUS on in situ oil and gas sites that do not currently have on-site generation to provide energy cost certainty, security, reduction in existing demand transmission service (DTS) and provide potential energy revenues.[3]
- Inclusion of the recently announced Alberta Carbon Capture Incentive Program.

Available Generic Generation Technologies

Cost estimates for new additions available to build within the 2024 LTO timeframe were primarily drawn from four sources of information. First, the United States (U.S.) Energy Information Administration's Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies[4] was utilized for many of its baseload generation costs. Second, is a Puget Sound Energy report prepared by Black and Veatch on the Characterization of Supply Side Options – Natural Gas-Fired Options.[5] This source was used to estimate costs for larger banks of reciprocating engines aggregated to a facility. Third, is a 2022 report titled 2022 Grid Energy Storage Technology Cost and Performance Assessment from the

[2] For more information on CCUS and cogeneration additions in the 2024 LTO, see the Emerging Technology Drivers section.

[3] For more information on CCUS and cogeneration additions in the 2024 LTO, see the Emerging Technology Drivers section.

[4] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf

[5] https://www.pse.com/-/media/PDFs/001-Energy-Supply/001-Resource-Planning/23_IRP17_AppP_100517c.pdf

Pacific Northwest National Laboratory for its information on pumped hydro assets.[6] Lastly, a 2022 technology report for capital cost data prepared under contract for the AESO from Guidehouse Inc.[7] was utilized for expected wind, solar, and battery energy storage capital and operating costs for Alberta-based projects.

The utilized list of technologies that could build within the AESO's long-term capacity expansion tool includes a majority of generation technologies currently observed in Alberta as well as potential future technologies. New technologies and costs continue to emerge as worldwide adoption, economies of scale, and innovation act as significant drivers for new projects. The list of technologies available and associated cost and operating assumptions are in Table 1.[8]

Table 1: Resource Inputs (2024).

Overnight Capital Costs (2022 Dollars)	Overnight Capital Cost, $/kW	Investment Tax Credits, $/kW	Net Overnight Capital Cost, $/kW	Fixed O&M, $/kW-yr	Variable O&M, $/MWh	Efficiency or Heat-Rate, % or GJ/MWh	Useful Life, Years	Capacity, MW
Battery Energy Storage	1,837	551	1,286	48.67	-	0.83	13	50
Pumped Hydro Energy Storage	3,543	1,063	2,480	38.05	-	0.80	40	20
Compressed Air Energy Storage	1,648	494	1,154	21.76	-	0.52	30	20
Natural Gas Simple-Cycle (Frame)	1,021	-	1,021	10.03	6.45	10.45	25	233
Natural Gas Simple-Cycle (Aeroderivative)	1,683	-	1,683	23.35	6.73	9.63	25	47
Natural Gas Simple-Cycle (Reciprocating Engines)	1,948	-	1,948	19.07	11.92	8.71	25	111
Natural Gas Combined-Cycle	1,553	-	1,553	20.20	3.65	6.79	30	418
Hydrogen Simple-Cycle (Frame)	1,021	153	868	10.03	6.45	10.45	25	233
Hydrogen Simple-Cycle (Aeroderivative)	1,683	252	1,431	23.35	6.73	9.63	25	47
Hydrogen Combined-Cycle	1,553	233	1,320	20.20	3.65	6.79	30	418
Combined-Cycle with CCUS	3,554	1,473	2,080	39.53	18.28	7.52	30	377
Combined-Cycle with CCUS Retrofit	2,001	1,241	760	39.53	18.28	9.7% Increase in Heat Rate		Various
Solar - 2024	1,689	507	1,182	27.05	-	-	25	50
Wind - 2024	1,531	459	1,071	88.65	-	-	30	100
Nuclear Fission	8,653	1,298	7,355	174.23	3.39	11.19	40	2156
Nuclear Fission (SMR)	8,867	-	8,867	136.07	4.30	10.60	40	300
Dammed Hydro	14,545	2,182	12,363	42.77	-	-	40	400
Nuclear Fission (SMR) - Alternative Decarbonization	8,867	-	8,867	136.07	4.30	10.60	40	300

[6] https://www.pnnl.gov/sites/default/files/media/file/ESGC%20Cost%20Performance%20Report%202022%20PNNL-33283.pdf

[7] AESO Materials | Forecasting Insights | AESO Engage

[8] Resource inputs for additional forecast years are available in the 2024 LTO Data file and Power BI Dashboard.

Overnight Capital Costs (2022 Dollars)	Overnight Capital Cost, $/kW	Investment Tax Credits, $/kW	Net Overnight Capital Cost, $/kW	Fixed O&M, $/kW-yr	Variable O&M, $/MWh	Efficiency or Heat-Rate, % or GJ/MWh	Useful Life, Years	Capacity, MW
Combined Cycle with CCUS Retrofit - Alternative Decarbonization	4,002	2,481	1,521	39.53	18.28	9.7% Increase in Heat Rate	0	Various
Battery Energy Storage - Alternative Decarbonization	1,706	512	1,195	43.32	-	0.83	13	50

The above costs are estimations of what developers may expect for greenfield projects. There may be opportunity for cost savings if new generation projects are located on brownfield sites or if existing facilities are modified and repowered, as they can take advantage of on-site resources, as well as natural gas and electric transmission facility connections. Locating new generation units on brownfield sites could decrease overall capital costs by approximately 10 per cent and fixed operations and maintenance costs by 40 per cent.[9] Similarly, existing coal-to-gas facilities could be modified into combined-cycle facilities using new combustion turbines. Based on high-level, public costs estimates, repowering facilities using existing equipment could reduce capital costs by as much as 35 per cent as compared with new combined-cycle facilities. While additional coal-to-gas repowering projects provide comparative low-cost power, they were not included as an option to economically build within the 2024 LTO, as there have been no recent proposals that suggests existing generators are considering repowering projects, given the current supply mix.

Table 2: Estimated Cost Comparisons for Greenfield and Brownfield Projects.

Project	Site	Capital Cost, $M	Capacity, MW	Overnight Capital Cost, $/kW
Genesee 1+2 Repowering[10]	Brownfield	1,350	1,332	1,013
Milner Repowering[11]	Brownfield	300	300	1,000
Proposed Sundance Repowering (cancelled)[12]	Brownfield	829	730	1,135
Cascade[13]	Greenfield	1,500	932	1,609
New Combined Cycle Facility	Greenfield	650	418	1,553

Where applicable, costs were modified to 2022 dollars.

[9] Appendix E, *supra* note 5.

[10] https://www.capitalpower.com/media/media_releases/capital-power-reports-second-quarter-results-and-announces-a-6-common-share-dividend-increase/

[11] https://maximpowercorp.com/wp-content/uploads/NewsRelease_2023_Oct24.pdf

[12] https://www.newswire.ca/news-releases/transalta-advances-its-clean-energy-investment-plan-858553389.html

[13] https://kineticor.ca/operation/cascade-power-project/

Retirement Methodology

The AESO's long-term capacity expansion tool was also used for assessing asset retirements by considering both the end-of-life timeframe and economic factors as key determinants. Retirements are determined by evaluating whether the assets can cover their fixed costs and variable costs over the course of the remaining useful life, considering operational run times and associated costs, and returns based on market clearing prices. This holistic analysis ensures an effective context in understanding of the economic viability and sustainability of existing and new assets, offering a robust framework for how the AESO may see the market evolve over time.

The retirement outlooks are then analyzed and amended as appropriate for any external factors such as early retirements, announced conversions, or mothballs that have been publicly announced. For certain natural gas generators, the AESO added the ability for the model to economically determine if retrofitting existing facilities with alternative fuels or integrating carbon capture technologies are feasible, thus potentially extending the asset's prescribed lifespan.

Renewable Generation Forecast Methods

With increased interest in renewable generation from the corporate sector, increasing public focus on decarbonization, and advancements in technological development and maturity of wind and solar technologies, renewable energy has witnessed flourishing global demand. Alberta's wealth of attractive wind and solar regimes and relative ease of entry into the Alberta electricity market have fostered development of Alberta's renewable generation resources at an increasing pace. The AESO has refined its renewable forecasting assumptions and methodology, taking a multifaceted approach to assessing renewable generation expectations within the forecast horizon.

Renewable generation technologies can include a diverse suite of wind, solar, hydroelectric, geothermal, bioenergy and other generation types. For the purposes of the 2024 LTO, the AESO has focused its forecasting efforts on wind and solar generation, which make up the vast majority of renewable electricity generation resources under development in Alberta. Although other forms of renewable generation may have applications and development opportunities in Alberta, industry focus is presently concentrated on commercialization of relatively mature solar and wind generation technologies. In the 2024 LTO, new wind and solar facilities were added both exogenously, based on demand for corporate PPAs, and as economic builds via the long-term capacity expansion tool.

Expert Cost Forecasts

The AESO's renewable generation forecast relies on generation capital cost, operating cost and operating characteristic data derived from expert external forecasts. The AESO engaged Guidehouse Inc. in 2022 to produce a cost and characteristic report for solar and wind renewable generation sources and energy storage technologies.[14] The cost and operating characteristics were used to inform inputs, which determine the relative economics of generation additions. The characteristics also inform the expected costs required to create an acceptable return on investment from the perspective of a long-term contract. The AESO adjusted the U.S. dollar (USD) forecast values for annual capital and operating costs estimates to Canadian dollars (CAD) using an exchange rate of $1.35 CAD-USD.

Since fixed and variable operating costs are relatively low for wind and solar renewable generating assets, the focus of wind and solar project economics is significantly dependent on forecast capital costs, weighted average cost of capital (WACC), revenue sources and expected production of electricity.

Capital Costs and Financing

The WACC is expected to be lower for fully contracted renewable projects than for market-exposed fully merchant generation projects. For the 2024 LTO generation forecast, the AESO modeled a seven per cent pre-tax WACC as a representative hurdle for fully contracted generation projects with an offtake from an investment-grade credit rated buyer. This WACC dominantly applied to renewable developments with a PPA. Comparatively, merchant projects were modelled with a 10.5 per cent pre-tax WACC, which applied to all renewables that could be built by the long-term capacity expansion tool. The AESO anticipates that this return expectation could decline with a stronger credit rated offtake agreements, longer term PPAs and construction risk mitigation factors, via access to lower debt carrying costs and higher levels of debt-to-

[14] *Supra* note 6.

capitalization on projects, governed by the ability to preserve minimum debt service coverage ratios (DSCR) with risk-adjusted cash flow.

Depending on the exposure of revenue sources to market volatility, the level and quality of contracted revenue, expected costs and expected production, renewable generation projects can attract relatively high amounts of debt carrying capacity. The AESO models renewable generation financing structures with 75 per cent debt and 25 per cent equity. This assumption is based on minimum debt service coverage guidance from credit ratings agencies, which informs debt carrying capacity in the AESO's renewable generation forecast.[15]

Generation output is a key driver of the levelized cost of electricity and relative generation economics. State of the art wind turbine generators can achieve capacity factors higher than 40 per cent in Alberta, while solar tracking facilities can exceed 20 per cent capacity factors, depending on siting and configuration of the assets. In modeling of these renewable generation forms, the AESO estimates 39 per cent average capacity factors for new wind generation facilities and 20 per cent capacity factors for new solar generation facilities to represent fleet averages of new assets, understanding that individual project capacity factors may vary based on technological configuration, siting, and annual resource availability.

Project Development Timelines

Compared to thermal and hydroelectric power stations of various types, renewable wind and solar projects can be developed and constructed in relatively short timelines of one or two years. This characteristic enables new generation from wind and solar to achieve commercialization more quickly than other generation projects, avoiding certain constructions risks.

Investment Tax Credits and Accelerated Depreciation Provisions

Investment tax credits (ITCs), announced by the federal government, are expected to reduce the net development cost of many low-carbon electricity sources by 30 per cent. The ITC for clean technology and the ITC for clean electricity is expected to enhance the renewable electricity generation outlook, as developers will face lower net capital costs for renewable and low-carbon electricity systems. Although these ITCs can apply to many different technologies including wind, solar, certain hydroelectric, small modular reactors, geothermal energy systems and stationary electricity storage, the AESO expects that in Alberta's electric system the ITCs will impact the continued development of already-mature wind and solar generation due to the competitive cost of these technologies, relative ease of development, finance ability and abundance of resources in the province.

In addition to government subsidization via ITCs, renewable energy investments also receive significant income tax incentives from Class 43.2 and 43.1. The enhanced first-year allowances and attractive accelerated depreciation rates enable significant tax avoidance for renewable projects, which provides significant subsidization compared to other generation types.[16] Although these accelerated depreciation tax incentives are not new, mature wind and solar renewable generation technologies are expected to benefit the most from these measures.

[15] https://www.spglobal.com/_assets/documents/ratings/research/101311439.pdf

[16] https://natural-resources.canada.ca/sites/www.nrcan.gc.ca/files/2019%20Tax-Incentives-Businesses__EN_v2.pdf

The federal government has also created a $1.56 billion Smart Renewables and Electrification Pathways Program which is providing substantial capital subsidies of $178 million to solar, geothermal, and battery energy storage projects across Alberta. These subsidies are expected to bolster renewable development, particularly solar, in the near term.

Corporate Interest and Environmental, Social and Corporate Governance (ESG) Perspectives

Environmental, social, and corporate governance (ESG) objectives also play a dominant role in enabling long-term renewable electricity developments. As firms aim to mitigate the environmental impacts of their products and services, renewable electricity PPAs have become a popular and relatively affordable form of scope 2 emissions[17] management. Renewable PPAs can take several forms with unique contract provisions, but in general terms, the agreements tend to provide either renewable attributes in the form of renewable energy certificates (RECs), or both renewable attributes and electricity in exchange for a fixed price. Depending on the buyer's appetite for renewable electricity, demand may also be specific to technology type, location of generation, generation project, term of contract, and price of RECs or renewable electricity delivered under an agreement.

With consideration to the diverse demands for corporate renewable electricity PPAs, the AESO performed a market survey of the ESG reports from the top 300 Canadian publicly traded companies, ranked by market capitalization, and the top 50 U.S. multi-national corporations, to gain an understanding of the demand for RECs and renewable electricity. The AESO then estimated the capacity of this demand that might be sourced from renewable electricity projects sourced in Alberta and estimated the probability that a firm would engage in an Alberta-sourced renewable electricity PPA, based on its footprint of operations in the province, the credit rating of the firm, the firms stated appetite for renewable electricity or objectives defined within their ESG reports, the firms existing progress towards ESG objectives, and the firm's financial capacity to engage in long-term contracts.

Using this approach, the AESO was able to estimate the quantity of megawatt hours (MWh) of renewable electricity demand that might be sourced from Alberta-based renewable electricity PPAs. Using the estimated capacity factors for new renewable generators, the AESO was able to gauge an estimate of the installed capacity of wind and solar assets that would be required to satisfy the demand for RECs and renewable electricity. This estimate provided one facet of the AESOs approach to renewable generation forecasting in the 2024 LTO.

[17] Scope 2 emissions are those associated with the consumption of purchased electricity, heating, and cooling.

Revenue Sources for Renewable Generation

Renewable generation capital deployment decisions are often driven by risk-adjusted cash flow-based investment metrics such as internal rates of return, payback period, profitability index and net present value. These metrics vary with the timing and magnitude of costs and revenues attributed to a project.

Renewable electricity in Alberta generally attracts two sources of revenues: electricity generation and renewable attributes. The electricity is transacted with the power pool while the renewable attributes present renewable developers with several monetization options.

Developers can choose to sell renewable attributes, or RECs, to a voluntary buyer via a corporate agreement. The incentive to purchase electricity from renewable sources relates primarily to organizational sustainability objectives focused on reducing emissions and the environmental impact of electricity consumption from corporate business activities. Within the 2024 LTO Reference Case, the AESO has assumed that the high-performance benchmark for electricity will decline to zero by 2050 to align with provincial decarbonization objectives. As a result, electricity in Alberta will have very low emissions in the longer term, which could diminish the corporate demand for scope 2 emissions reductions from the electricity sector and reduce expected returns form RECs in the long run. The potential decline of the REC value was modeled as a simple 25 per cent discount to the prevailing compliance cost throughout the forecast period.

As an alternative to selling RECs in a voluntary market, a seller may use or commoditize the renewable attributes as a regulatory carbon compliance mechanism. In Alberta, renewable generators may be able to choose to create registered carbon offsets from wind or solar projects, based on the Electricity Grid Displacement Factor (EGDF), or monetize emissions performance credits (EPCs) generated under the *Technology Innovation and Emissions Reduction* (TIER) *Regulation,* based on the high-performance benchmark for electricity. Presently, carbon offsets prescribe a higher emissions intensity value (tonne/MWh) than EPCs, so projects that have the option of generating offsets will receive higher value for the environmental attributes than projects that generate EPCs. However, in its update to TIER, the Government of Alberta scheduled the EGDF to decline until 2029.[18] Thereafter, the EGDF will align with the high-performance benchmark for electricity, eliminating the incentive to produce offsets instead of EPCs. The Government of Alberta has not provided guidance on the high-performance benchmarks regulated under TIER beyond 2030.[19]

Electricity Market Revenue

Another key revenue source for renewable generators is the pool price received for generating electricity in the Alberta market. The value of electricity corresponds to the fundamental supply and demand balance at the time of electricity production. Renewable generators tend to have strongly correlated production, which could lead to supply surplus events when the quantum of generation is significant. As increasing volumes of renewable generation enter the Alberta market, there is the potential for the electricity generation revenue stream to decline, which may put more reliance on the monetization of renewable attributes as a driver for renewable generation.

[18] https://www.alberta.ca/assets/documents/epa-technology-innovation-and-emissions-reduction-system-amendments-webinar.pdf.

[19] For more information on the assumptions for the *TIER* high-performance benchmark used in the 2024 LTO, see the Policy and Regulatory Drivers section.

Cogeneration Forecast

The AESO's 2024 LTO forecast for electricity cogeneration relies on the forecast production of hydrocarbons and hydrogen as primary products. The cogeneration forecast is added exogenously to the AESO's long-term capacity tool,[20] prior to simulation of competitive supply additions and retirements. Cogeneration is generally considered to be a high-efficiency use of fuel gas, generating useful heat and electricity at the source of industrial consumption. Some industrial sites with cogeneration have added benefits to project economics due to tariff treatment of industrial sites. The cogeneration forecast for the 2024 LTO expects continued development of brownfield oil sands cogeneration expansion facilities intended to supply thermal and electric energy to hydrocarbon production facilities. The forecast cogeneration additions are aligned with the AESO's demand forecast from oil sands sites[21] and capacity is calibrated using steam-to-oil ratios from modern oil sands sites.

Presently, regulatory risks to continued oil sands expansion include the recently announced federal emissions cap targeting the oil and gas sector and the *Clean Electricity Regulations* (CER), creating uncertainty to the continued viability of cogeneration in Alberta. Risks to the cogeneration forecast could include changing techniques in oil extraction, such as solvent extraction, and changes to hydrogen production methods.

Hydrogen-fired cogeneration facilities are modelled based on the Air Products facility under development in Fort Saskatchewan. The plant is expected to have 93 MW of combined gas-turbine and steam-turbine capacity, expected to operate in a base load method, fired on 100 per cent hydrogen gas. The facility will produce 1,500 tonnes of hydrogen per day. In the AESO's hydrogen-fired cogeneration forecast, 465 MW cogeneration related to hydrogen production is forecast throughout the 20-year horizon. Total cogeneration facilities were modelled in tandem with the expected development of hydrogen production facilities from the AESO's electricity load forecast.

Storage Methodology

Storage technologies can play a role in supporting resource adequacy because they can store energy during periods of high renewable generation and low prices that can then be used during times with low renewable generation and relatively higher prices. They also provide reliability via ancillary services, as they can respond quickly to frequency deviations and grid disturbances. Storage technologies have been steadily increasing in Alberta over the last several years, with a total of 190 MW of stand-alone storage integrated into the grid by the end of 2023.

Within the LTO, there were three components impacting the buildout of storage resources. The first was inclusion of the near-term projects that met the inclusion criteria within the initial build-out of the model. The second was an exogenous build out of storage technologies that could participate in ancillary services as a primary revenue resource, and a further replacement of these resources as they reach end-of-life and retire. The third was the ability for the AESO's long-term capacity expansion tool to economically build standalone batteries.

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[20] For more information on cogeneration additions in the 2024 LTO, see the Emerging Technology Drivers section.

[21] For more information on forecast oil sands demand in the 2024 LTO, see the Load Methodology section.

Intertie Methodology

Interties are transmission facilities that link one or more electric systems outside Alberta to one or more points on the Alberta Interconnected Electric System (AIES). Alberta transfers electric energy across interties with three neighbouring jurisdictions: British Columbia (BC), Montana (MT) and Saskatchewan (SK).

System reliability standards define the criteria that determine the amount of energy that can be transferred between jurisdictions. These standards impose three limits on transfers between control areas. The available transfer capability (ATC) limits imports and exports on an individual transfer path to reflect operational conditions and maintain the transmission reliability margin (TRM). The system operating limit specifies the maximum import and export capability between Alberta and all neighbouring jurisdictions. A combined operating limit on the BC and MT interties further restricts the transfer capability of total energy transfers between Alberta and BC/MT.

Trade between jurisdictions is determined by market participants who submit bids and offers into the energy market merit order. The Alberta interties are indirectly linked to western markets in Mid-Columbia (Mid-C) and California and to eastern markets in Midcontinent Independent System Operator (MISO).

The three neighbouring jurisdictions were modeled as a proxy load and generator. Each jurisdiction had a single point load equal to the maximum export amount from Alberta and a single generator with capacity equal to the single point load plus the total maximum import amount. This setup allows Alberta to fully export when the proxy generator has zero output, and to fully import when the proxy generator is at full output.

Blocks and hourly price points were used for the economic operation of the proxy generators. For the BC and MT interties, normal hydro years were identified, and Mid-C hourly market heat rate shapes were created for each month. Proxy unit blocks and block quantities were determined by comparing historic import levels to Alberta market heat rates. The blocks are then adjusted by the previously created heat rate shapes. A similar process was used to determine heat rate blocks and price points on the SK proxy generator, except MISO (LMP Point SPC) market heat rates were used to create the heat rate shapes. In addition to the price points for the three jurisdictions, wheeling costs were also input. These wheeling costs are applied to energy that gets transferred over the interties.

Capability between jurisdictions has been reduced to reflect system operating limits that occur. Limits within the model have been based on historical Alberta limits and vary hour to hour. The limits also change depending on the year to represent potential increases in the intertie capability. The table below shows the import and export limits assumed within the model.

Table 3: Intertie Average Capability and Maximum Capability Assumptions.

	Average Capability	Max Capability
WECC import ATC – before 2026	484	650
WECC import ATC – 2026 to 2029	760	934
WECC import ATC – after 2029	1,261	1,434
WECC export ATC – before 2030	935	935
WECC export ATC – 2030 and beyond	1,435	1,435
SK import ATC is 153 MW	153	153
SK export ATC is 153 MW	153	153

The Alternate Decarbonization scenario assumes an increase in intertie capability. In that scenario, the BC intertie is approximately doubled in 2035 resulting in increased capability for the Western Electricity Coordinating Council (WECC) BC/MT interties. The combined import capability for BC/MT is assumed at 2,645 MW and combined export capability assumed at 2,650 MW.

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