AESO 2024
Long-Term Outlook

MAY 2024

Contents

Value Through Insights

A Message on Behalf of the Executive Leadership Team

> *The AESO's* ***leadership*** *in the transformation of Alberta's power sector relies on* ***robust*** *forecast information.*

The Alberta Electric System Operator (AESO) is excited to share key insights and strategic outlooks from the *2024 Long-Term Outlook* (LTO). This forecast, extending over the next two decades, charts an expected trajectory of Alberta's load and generation based on current assumptions. It lays the groundwork for our transmission system planning, long-term adequacy assessments and market evaluations.

Compared to the 2021 LTO, our energy load growth projections over the next 20 years have increased from an annualized average rate of 0.4 per cent to 1.2 per cent. This outlook is supported by macroeconomic factors, oil sands production and the initiation of new load connection projects. Further, the AESO foresees substantial long-term growth spurred by the electrification of transportation, heating and industrial sectors. Further upside to load growth may come from developing areas including data centers and the increased computing needs associated with artificial intelligence platforms.

On the generation side, the AESO anticipates continued expansion, with natural gas expected to emerge as the leading dispatchable fuel source, marking a significant transition from coal. In addition, the 2024 LTO forecasts anticipated continued growth in wind and solar supplemented by energy storage over the first half of the forecast. This evolution is driven by a confluence of factors, including changing technology costs, government policies, corporate power purchase arrangements for renewables, coal plant retirement schedules and profitability expectations.

The 2024 LTO is written amidst substantial uncertainty, driven by ongoing and new shifts within Alberta's electricity landscape. Developments in government policy, technological innovation, and changes in production and consumption patterns call for a planning approach that is both flexible and responsive. To navigate these uncertainties, the AESO has created multiple scenarios alongside our primary corporate forecast. Furthermore, the AESO acknowledges that the 2024 LTO is a starting point for further assessments as changes are contemplated in key rules and regulations including the Restructured Energy Market and *Transmission Regulation*.

These scenarios contemplate various possible futures and highlight our commitment to adaptability and foresight in strategic planning. Along with our stakeholders, the AESO will address opportunities and challenges to ensure the future electricity needs of Alberta are met.

Nicole LeBlanc
Vice President, Markets

Key Highlights

Load

- **Macroeconomic factors:** The near-term is driven by strong macroeconomic factors, including oil sands production and new load connection projects; long-term growth fueled by electrification of different sectors of the economy (transportation and buildings) and growth in nascent industrial sectors (hydrogen).
- **Stable load growth:** While load growth is robust through the forecast period, a doubling or tripling of Alberta internal load (AIL) is not expected; however, past the forecast period an acceleration of electrification trends may lead to a doubling of load.
- **High Electrification:** This tests the potential for increased load growth spurred by rapid adoption of electric vehicles (EVs), along with the electrification of buildings' heating and cooling systems, leading to an annualized average rate of 1.9 per cent over the forecast period.
- **Impact of data centers:** Potential shocks to load growth may include data centers though the mid-term; this growth will be carefully monitored and assessed.
- **Acute ramps of AIL:** The compound effect of distributed solar energy with the electrification of vehicles and buildings will lead to frequent and acute ramps of AIL, potentially adding more challenges to overall system flexibility.
- **Winter peaking:** Alberta is expected to remain a winter peaking grid due to extreme temperatures and additional load requirements from transportation and building electrification.

Generation

- **Decarbonized baseload generation:** Early and pronounced advancement of decarbonized generation technologies, such as carbon capture, utilization and storage (CCUS) equipped combined-cycle units followed by nuclear small modular reactors (SMRs), addresses escalating load demands.
- **Value of dispatchable resources:** As the energy transition progresses the need for more and varied dispatchable flexible generation is expected to partner with increased adoption of variable generation.
- **Federal investment tax credits:** The provision of significant federal investment tax credits reduces capital costs for low or non-emitting generation technologies and enhances the competitiveness of CCUS, wind, solar power and energy storage.
- **Power purchase arrangements:** In addition to tax incentives, renewables growth is further driven though long-term corporate power purchase arrangements. By 2030, renewable capacity (including hydro, biomass, wind and solar) is expected to exceed peak demand and additions beyond that capacity are expected to be moderated.
- **Clean hydrogen:** Alberta's anticipated leadership in the clean hydrogen sector, emphasized by its natural gas resources and carbon sequestration capabilities, facilitates cost-effective production of blue hydrogen.
- **Indefinite path:** Significant technological cost and operational uncertainty is introduced by emerging technologies like CCUS, SMRs, and hydrogen production and electricity generation.

Insights

- **Resource adequacy:** The critical importance of maintaining resource adequacy is underscored to avert unserved energy, especially considering the expected retirements of coal-to-gas converted units by 2038.
- **Carbon emission reductions:** Emission trajectories across scenarios demonstrate a significant reduction between 2024 and 2030, aligning with federal objectives for renewable energy production and carbon emission reduction.
- ***Renewable Electricity Act*:** Within the 2024 LTO scenarios, it is anticipated that by 2030, Alberta will meet its objective of generating 30 per cent of its electric energy from renewable sources.

1. Background

1.1. Purpose

The AESO's *2024 Long-Term Outlook* (LTO) highlights Alberta's expected electricity demand over the next 20 years and the expected generation capacity needed to meet that demand. The 2024 LTO serves as the foundation for the AESO's *Long-Term Transmission Plan* (LTP),[1] which sets out Alberta's future transmission requirements, in accordance with the *Transmission Regulation*.[2]

The AESO acknowledges that significant work and effort remains ongoing around the shifting landscape for renewables development, evolutions to transmission policy and market structure.[3] Despite the uncertainties, the AESO regards the 2024 LTO as benchmark analysis, built on the existing assumptions of the current energy-only market construct and existing transmission regulations. The insights gained through this report will allow the AESO and stakeholders to identify and prioritize additional focus and work required in areas such as policy development, industry coordination, grid planning, market evolution and grid reliability operations. Given that development, decision-making, approval and implementation timelines in each of these areas can be lengthy, it is important to continue the conversation on the transformation now with the understanding that it will be an iterative process.

1.2. Creating the 2024 Long-Term Outlook

The LTO development process begins with an economic outlook for the province, as economic considerations are historically a core influence of load. The importance of economic factors in load growth forecasting is enhanced with the combination of energy transition and electrification trends.

> For more information, see the **Load Forecast Methodology** on aeso.ca.

The 2024 LTO generation forecast is based on this load growth outlook, policy considerations both provincially and federally, generation technology and resource availability. The AESO uses market simulation tools to assist in determining the likely future generation outlook, and develop robust, comprehensive assessments to inform modeling inputs and parameters, reflective of the technology and policy expectations.

> For more information, see the **Generation Forecast Methodology** on aeso.ca.

The 2024 LTO aligns with current and expected trends using the most up-to-date information. It relies on third-party information and is validated with consideration of other credible forecasts whenever possible.

Specifically, in addition to the LTP, the LTO is used as input into other AESO functions, including transmission system planning studies for Needs Identification Documents (NIDs) and connection projects, the Independent System Operator (ISO) tariff, and market assessments. The LTO also informs ongoing market evaluations, system flexibility and net-demand variability assessments, long-term resource

[1] https://www.aeso.ca/grid/long-term-transmission-plan/

[2] The Transmission Regulation can be found here: https://kings-printer.alberta.ca/1266.cfm?page=2007_086.cfm&leg_type=Regs&isbncln=9780779846269

[3] https://www.aesoengage.aeso.ca/market-pathways

adequacy analyses, policy and regulatory (including carbon emission policies) analyses, as well as other engineering and market reports.

The AESO continually reviews its forecasts and will, when appropriate, consider alternate load and/or generation assumptions in these other functions to align studied forecasts with the latest information.

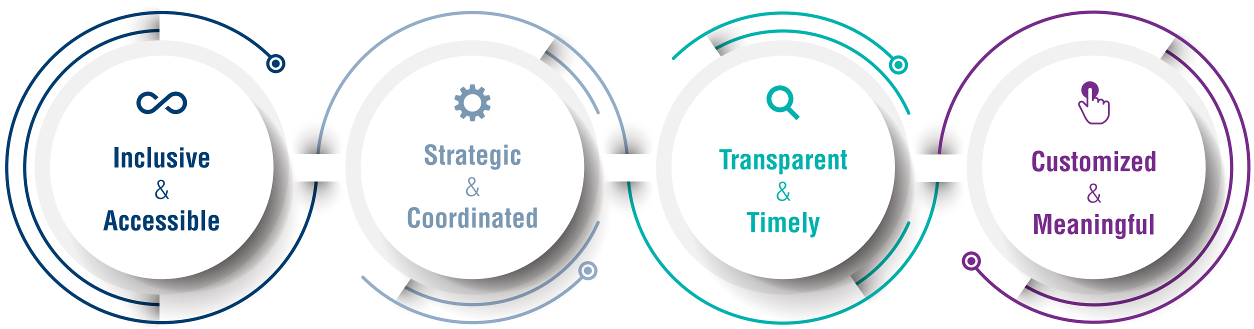
The AESO has taken a new modular approach to the 2024 LTO, with many parallel sections that can be reviewed by the reader in a customized order or preference. In combination with the highlights in the summary report, the LTO landing page[4] contains further explicit details around scenario results, insights, methodology, drivers and supporting data visualization and outputs. The modular approach enables the opportunity to provide additional insights driven by potential fundamental changes (i.e., policy, technology and framework) on a timely basis.

1.3. Stakeholder Engagement

The AESO develops comprehensive forecasts using third-party information, best practices in forecasting methodology and in-house expertise.

The AESO is committed to stakeholder consultations to gather their technological and market insights, validate assumptions and concerns, and understand their perspectives related to Alberta's electricity future.

In line with the AESO's Stakeholder Engagement Framework, the AESO provided opportunities to interact with and solicit feedback from stakeholders in developing the 2024 LTO. Specifically, the AESO hosted extensive engagement sessions whereby assumptions and preliminary results were presented for comment and feedback.[5]



[4] https://www.aeso.ca/grid/grid-planning/forecasting/2024-long-term-outlook

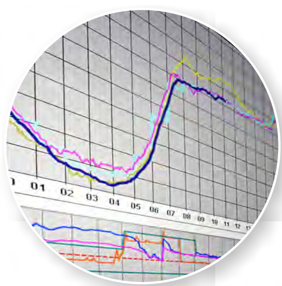
[5] https://www.aesoengage.aeso.ca/forecasting-insights

2. Long-Term Outlook Scenarios

2.1. Long-Term Scenario Framework

The *2024 Long-Term Outlook* (LTO) features four scenarios with variations in load and generation assumptions. These scenarios allow the AESO to capture possible future states of the Alberta market and answer "what if" questions.

TABLE 1: 2024 LTO Scenarios at a Glance



REFERENCE CASE

Incorporates the most pertinent economic and oil sands outlook, electrification trends and recent generation technological and cost advances. Decarbonization policies are consistent with the provincial government's target to achieve decarbonization by 2050 and serves as the base case for the 2024 LTO.

DECARBONIZATION BY 2035

This scenario includes the Reference Case load and federal *Clean Electricity Regulations* restrictions, as outlined in *Canada Gazette 1*, and assumes the *Technology Innovation and Emissions Reduction Regulation* high-performance benchmark for electricity declines linearly from 2030 to zero in 2035.

ALTERNATIVE DECARBONIZATION

This case starts with the Reference Case load, then explores the effect of increasing intertie connections with neighboring jurisdictions in 2035. This scenario anticipates technological cost declines and development timelines of CCUS, nuclear SMR, and hydrogen are delayed and, in turn, explores other technologies to bridge that gap.

HIGH ELECTRIFICATION

While holding the Reference Case generation assumptions constant, this scenario tests a higher bound of load growth through accelerated rates of electric vehicles adoption and electrification of building heating and cooling. Includes additional load from electrification and CCUS adoption in Alberta's heavy industries and the incorporation of additional load projects.

2.2. Scenario Highlights

2.2.1. Reference Case

The 2024 LTO's base-case load forecast is a foundational input for the Reference Case, the Decarbonization by 2035 scenario and Alternative Decarbonization generation projections. Near-term load growth is influenced by macroeconomic indicators such as gross domestic product (GDP), employment rates, population trends and the integration of load projects. Beyond 2030, the demand for electricity is poised to increase significantly, driven by an accelerated energy transition that sees higher adoption of EVs, hydrogen production, and the electrification of heating and cooling systems in buildings.

Exploring the expansion of energy efficiency measures and the adoption of distributed energy resources (DER) are avenues explored to offset the anticipated load growth. Additionally, the predictability of daily and hourly load variability becomes more challenging due to the unpredictability of EV charging, heating and cooling demands, and, to a lesser extent, rooftop solar generation. This variability leads to a notable increase in peak load demand, particularly from EV and building loads, compared to the average and total load.

In response to these trends, the planned addition of near-term natural gas-fired plants and continued increase in renewable energy capacity into the 2030s are expected to create periods of supply surplus in the mid-forecast timeline. Electricity generation throughout the period is anticipated to rely heavily on combined-cycle units and cogeneration facilities, retrofit with CCUS technologies, in response to both provincial and federal decarbonization targets and tax incentives. These carbon abatement actions are on existing capacity and thus if subject to delay are still available to provide energy to serve load. Furthermore, anticipated reductions in capital costs for advanced nuclear SMR technology are expected to support the economic viability of several nuclear SMR baseload projects in the later stages of the forecast period.

For more information, see the **Reference Case** on aeso.ca.

FIGURE 1: Reference Case – Average Alberta Internal Load (AIL) Forecast

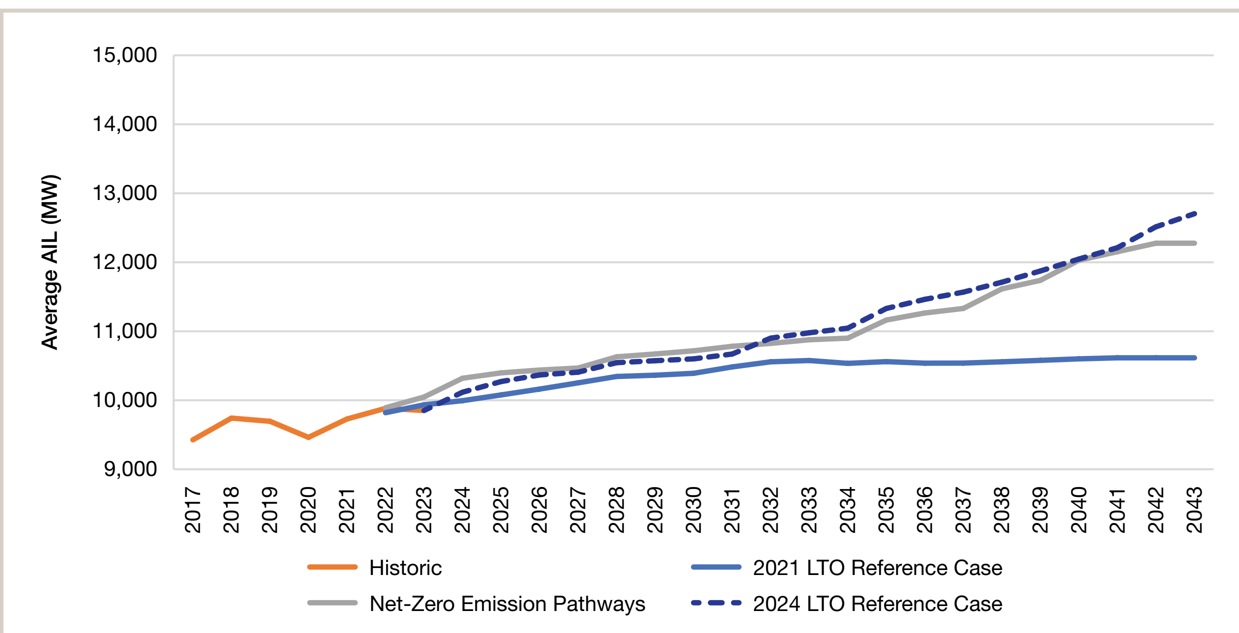
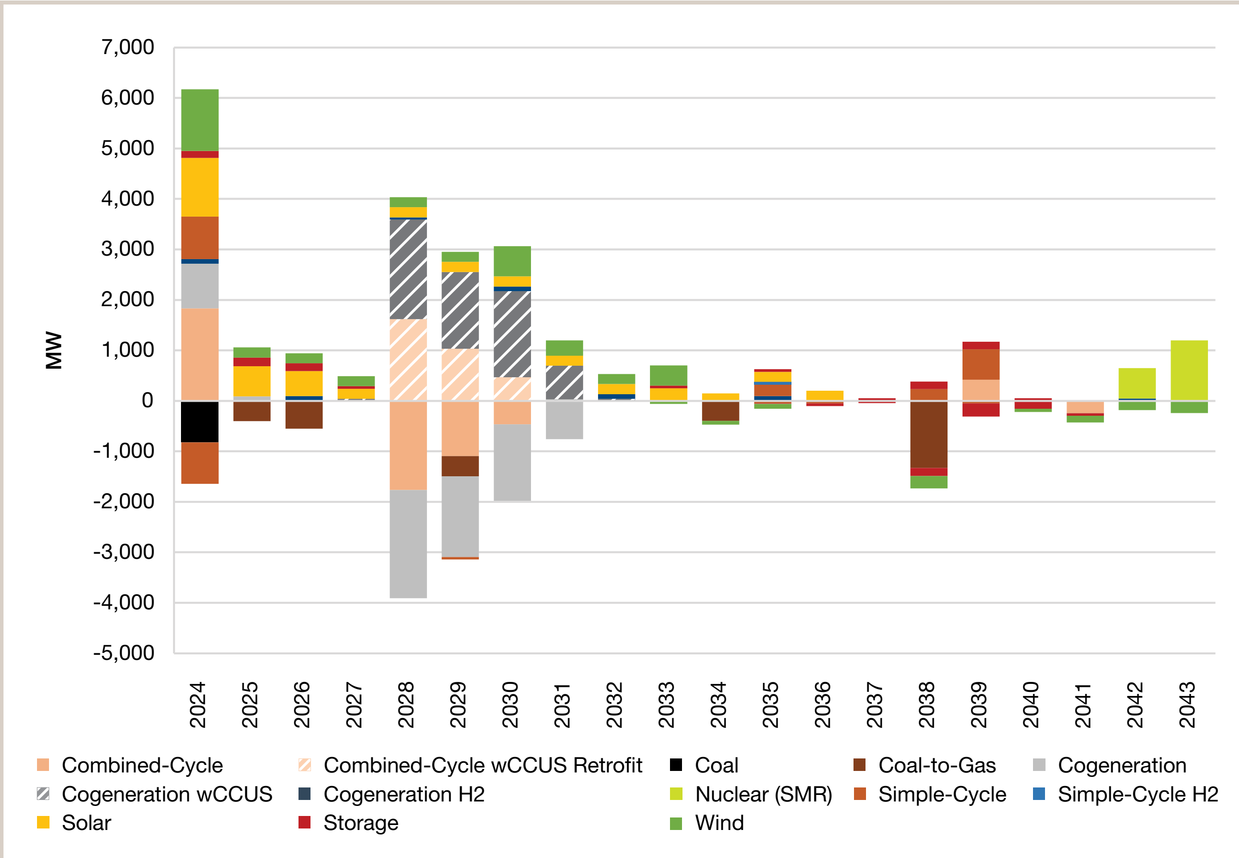


FIGURE 2: Reference Case – Capacity Additions and Retirements



2.2.2. Decarbonization by 2035

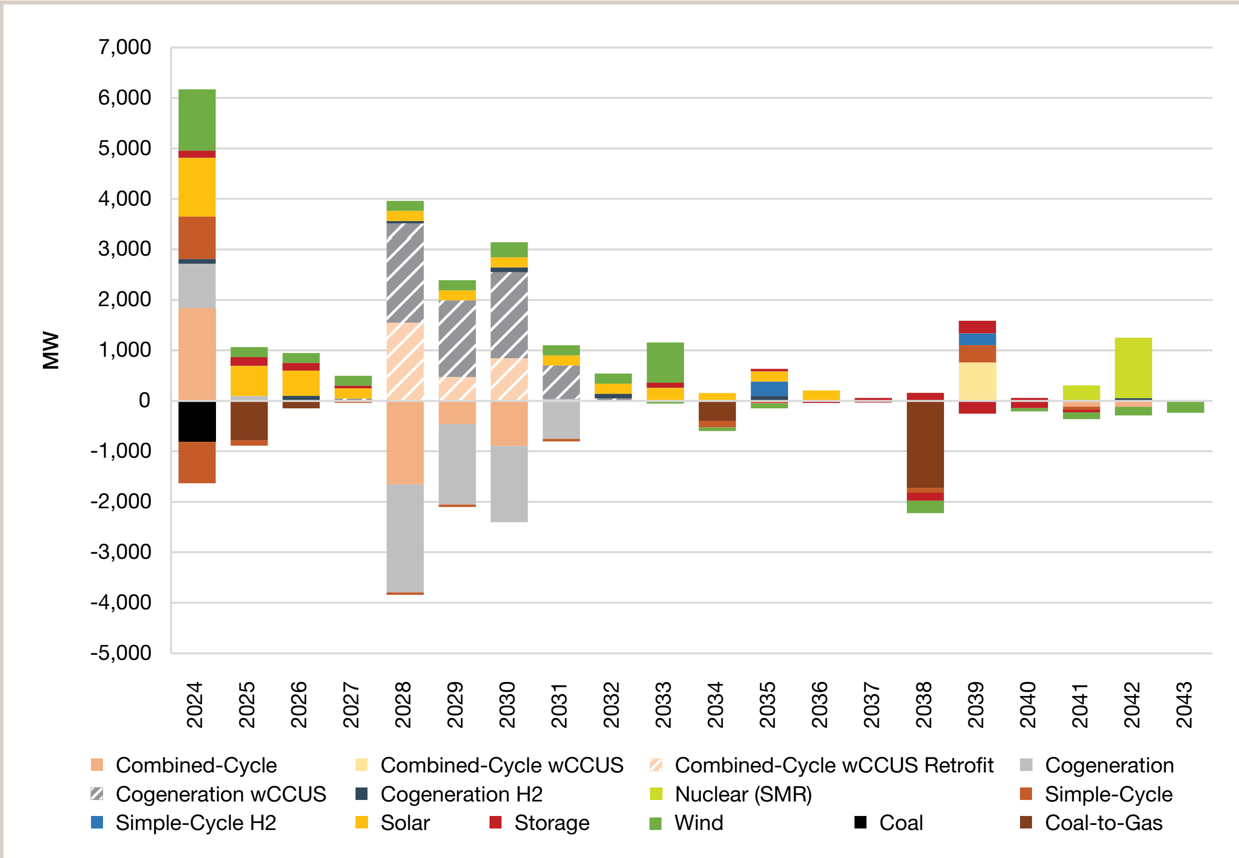
In the Decarbonization by 2035 scenario, generators that emit greenhouse gases and fail to comply with the *Clean Electricity Regulations* (CER) emissions performance standard of 30 tonnes per gigawatt-hour are limited to a maximum of 450 operational hours annually, posing significant reliability challenges for the Alberta Interconnected Electricity System (AIES) towards the end of the forecast period.

The regulations enforced by the CER may increase the uncertainty around CCUS retrofits, primarily due to expedited reductions in the *Technology Innovation and Emissions Reduction* (TIER) *Regulation* high-performance benchmarks for electricity, which diminish the anticipated revenue streams from CCUS projects. The CER may incentivize the development of alternative generation technologies, such as hydrogen-fired simple-cycle and new combined-cycle power plants equipped with CCUS, over traditional natural gas-fired generation. While these alternatives are low- or non-emitting, they usually come with higher costs and have not yet reached the same level of technological maturity as natural gas-fired options.

Following the CER's implementation, the Decarbonization by 2035 scenario anticipates an increase in electricity imports and a decrease in exports relative to the Reference Case. This is due to more stringent restrictions on natural gas-fired generation, reducing available generating capacity while demand escalates, necessitating additional power from external sources. However, with the integration of nuclear SMRs in 2041 and 2042, the balance of imports and exports is expected to realign with levels observed in the Reference Case.

For more information, see **Decarbonization by 2035** on aeso.ca.

FIGURE 3: Decarbonization by 2035 – Capacity Additions and Retirements



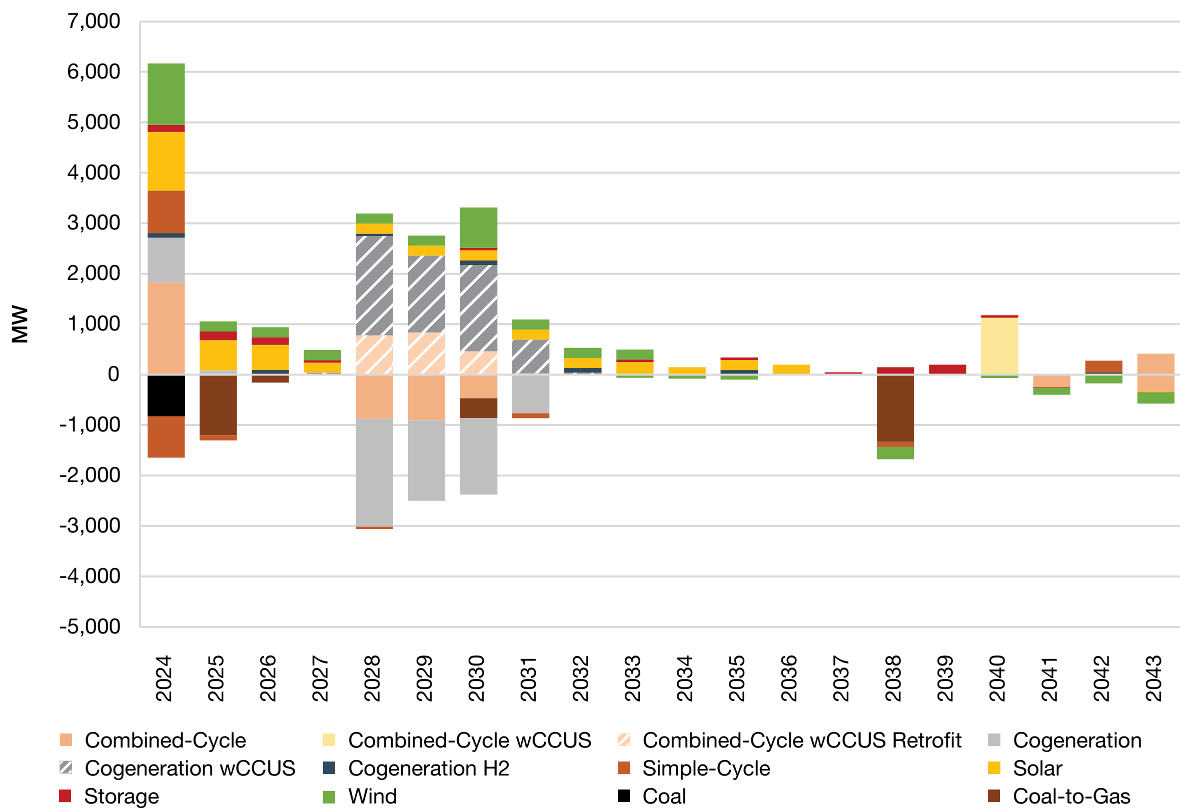
2.2.3. Alternative Decarbonization

The Alternative Decarbonization scenario adopts a conservative projection for the cost of emerging baseload technologies like nuclear SMRs and CCUS relative to the Reference Case. It also anticipates accelerated and more significant cost reductions for battery energy storage systems.

The scenario assumes the British Columbia (BC) intertie capacity to expand to double that of the Reference Case, enhancing import and export capabilities with adjacent jurisdictions. Unlike other 2024 LTO scenarios, the Alternative Decarbonization scenario does not foresee additions of nuclear SMRs and includes only a minimal number of CCUS retrofits. This highlights the importance of achieving cost reductions to the point of commercial viability for these technologies, aiming for “Nth-of-a-kind” cost efficiencies. Characterized by the lowest long-term capacity expansion among the LTO scenarios due to the capital cost profiles of these emerging technologies, the scenario relies on increased power imports via the BC intertie to meet demand.

For more information, see **Alternative Decarbonization** on aeso.ca.

FIGURE 4: Alternative Decarbonization – Capacity Additions and Retirements



2.2.4. High Electrification

The High Electrification scenario delves into the potential for increased load growth spurred by rapid adoption of EVs, along with the electrification of buildings' heating and cooling systems. This scenario also examines the rise in industrial loads from activities such as hydrogen production, though these contribute a smaller portion to the overall load increase.

Key inputs for the load model, such as macroeconomic factors and oil sands variables, are in line with those used in the Reference Case forecast. It also maintains the same assumptions for offsetting load growth, including energy efficiency measures and solar DER.

A notable aspect of this scenario is the significant impact of EV charging profiles on hourly load variability, with more pronounced fluctuations due to increased load ramps. There's a marked emphasis on the urgent development of baseload generation capacity to meet the demands of rapid electrification, a shift from the Reference Case's timeline. By mid-term, the energy demand is expected to be largely met by deploying combined-cycle units with CCUS technologies starting in 2037, while the long-term demand will require earlier and more widespread development of nuclear SMR baseload generation than the Reference Case suggests.

For more information, see **High Electrification** on aeso.ca.

FIGURE 5: High Electrification – Average AIL Forecast

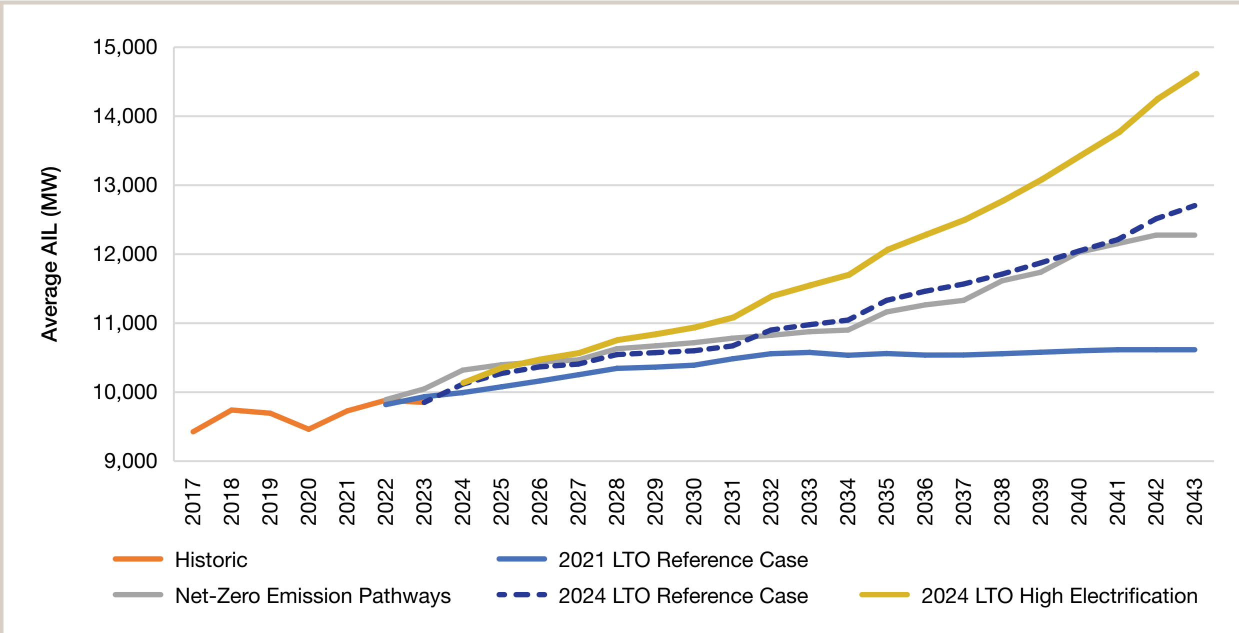
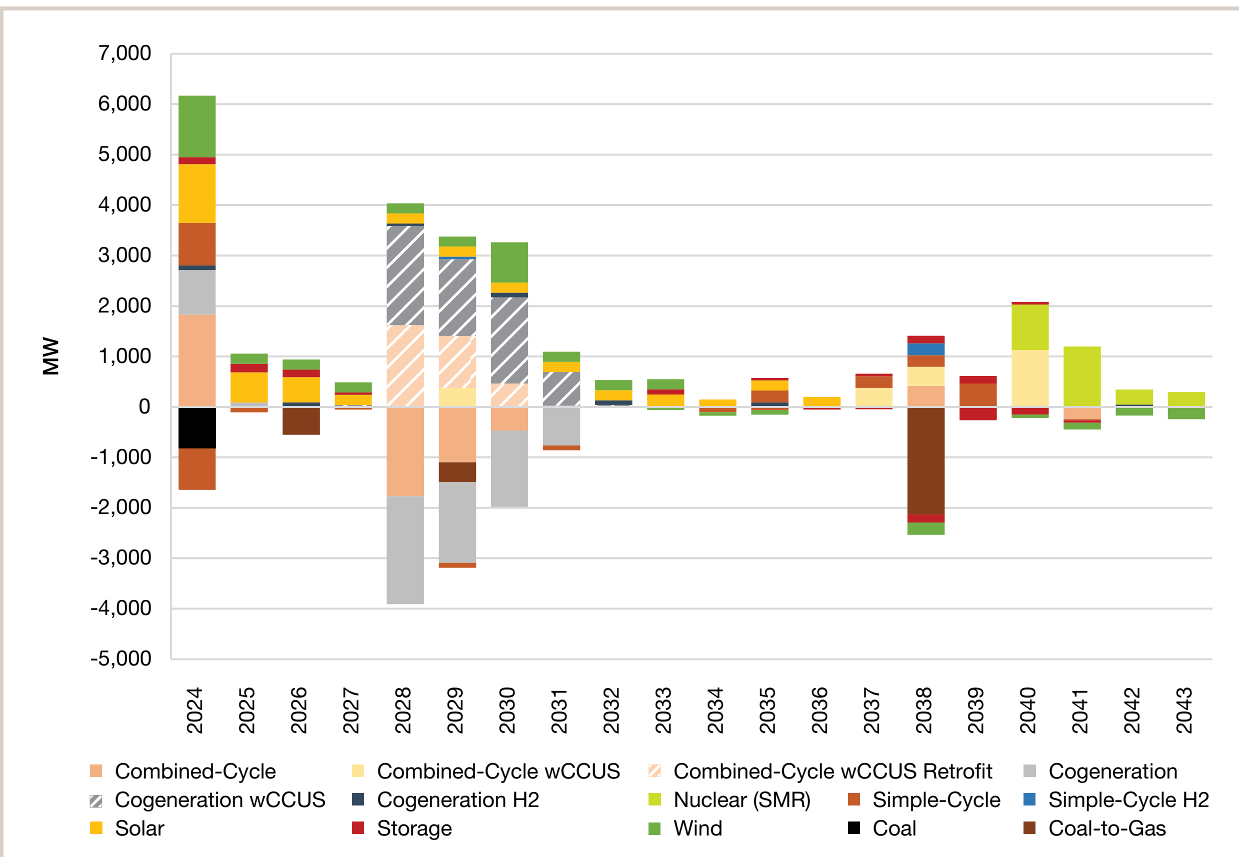


FIGURE 6: High Electrification – Capacity Additions and Retirements



2.3. Policy Context

The development of the 2024 LTO unfolded during a critical phase of regulatory transformation, heavily shaped by federal and provincial policies targeting decarbonization. Key among these changes is the adjustment to TIER, aimed at improving the accuracy of facility-specific and high-performance benchmarks, which in turn will increase compliance demands and costs for facilities not taking steps to mitigate impacts.

Additionally, the launch of refundable federal investment tax credits is set to significantly lower the upfront capital costs associated with developing low or non-emitting electricity generation technologies, expected to notably boost the growth of CCUS, along with wind and solar energy technologies. Furthermore, as outlined in Part I of the *Canada Gazette*, the CER is introducing stringent limits on natural gas-fired generation lacking emissions controls, likely challenging system reliability.

Lastly, the federal government's *2030 Emissions Reduction Plan*, with its ambitious targets for zero-emission vehicles adoption and building electrification, is anticipated to markedly affect electricity demand throughout the 2024 LTO period.

> For more information, see the **Policy and Regulatory Drivers** on aeso.ca.

2.4. Risks and Uncertainties

The 2024 LTO is crafted amidst significant uncertainty, fueled by ongoing and emerging shifts within Alberta's electricity landscape. Changes in government policy, technological advancements, and shifts in production and consumption patterns necessitate a planning approach that is adaptable and responsive. Additionally, AESO recognizes that the 2024 LTO serves as an initial assessment, with further evaluations anticipated as adjustments are considered in crucial rules and regulations, including the Restructured Energy Market[6] and *Transmission Regulation*.[7]

The 2024 LTO underscores the pivotal role of federal and provincial policies in shaping the future of generation resources and load development, highlighting how changes in carbon policy, incentives, or tax policy could drastically affect the underlying economics of anticipated demand patterns and generation portfolios.

The generation technologies presented in the 2024 LTO, primarily in early stages of commercial deployment, may see actual development costs, operational efficiency and costs deviating from initial estimates. Moreover, the cost estimates provided in the 2024 LTO represent generic facilities and do not account for site-specific costs or variations in financing, which could alter projected capital requirements. The social acceptability of generation projects is also increasingly crucial, with societal shifts potentially favoring certain technologies.

With factors such as economic growth, population increase, global trends, climate change and technological acceptability adding to the forecasting complexity, this analysis highlights the necessity for adaptability and comprehensive consideration in planning the future electricity landscape of Alberta. Decomposing load into multiple components such as base load and key load growth drivers such as electrification of transportation and buildings, allows for conducting sensitivity analyses on each of these components. Additionally, the level of industrial and commercial activity, particularly in sectors like manufacturing, mining and heavy machinery, alongside emerging sectors like data centers and offices, will play a significant role in driving electricity demand.

> For more information, see the **Risks and Uncertainties** on aeso.ca.

[6] https://www.aesoengage.aeso.ca/rem-technical-design

[7] https://www.aesoengage.aeso.ca/37884/widgets/156642/documents/125519

2.5. Emerging Technology Drivers

Alberta is strategically positioned to enhance its clean hydrogen sector, predominantly through the cost-efficient production of low-cost blue hydrogen. The province's access to copious natural gas feedstocks, coupled with its existing and proposed carbon sequestration infrastructure, positions blue hydrogen as the preferable utility-scale option for low-carbon hydrogen production.

Facilities in the oil sands, both with and without cogeneration capabilities, are anticipated to adopt CCUS technologies in the 2024 LTO timeframe. This trend is primarily motivated by the increasing costs associated with emissions, the availability of significant investment tax credits and, for sites lacking cogeneration, the potential to avoid demand transmission service (DTS) and electricity import fees.

Additionally, nuclear SMRs offer the potential for shorter construction periods and reduced capital expenditures compared to conventional nuclear power plants. Their compact size also mitigates reliability concerns during contingencies. Nonetheless, social acceptance remains a considerable hurdle and the technology is still in the nascent stages of commercial application.

For more information, see the **Emerging Technology Drivers** on aeso.ca.

2.6. Implications, Insights and Outcomes

2.6.1. Costs

From a levelized cost perspective, the availability of significant investment tax credits for combined-cycle with CCUS and emissions performance credits for solar and wind technologies positions these generation methods as the most cost-effective. Nuclear SMR technology is anticipated to achieve cost parity with traditional natural gas-fired generation technologies on a levelized basis, factoring in first-of-a-kind installation costs, when incorporating carbon cost projections and investment tax credits.

The escalating cost of carbon, coupled with declining high-performance benchmarks for electricity, positions hydrogen-fired combustion technologies to achieve cost parity with their unabated natural gas counterparts by 2038, subsequently improving their cost competitiveness. Variations in carbon costs and credits across scenarios largely depend on the specific carbon pricing policy applied to electricity, rather than on differences in capacity development.

2.6.2. Resource Adequacy

The Alberta generation supply forecast for the Reference Case, High Electrification and Alternative Decarbonization scenarios is expected to meet the resource adequacy standards in the base years of 2028, 2030, 2033, 2035 and 2043, indicating low to negligible risk. 2038 is expected to see an increase in supply shortfall, mainly due to the retirements of coal-to-gas conversion units. The winter months pose the highest risk for expected unserved energy (EUE), correlating with peak load periods in the province.

Under the Decarbonization by 2035 scenario, the risk of unserved energy escalates, with EUE reaching up to 174,000 megawatt-hour (MWh), predominantly during high-demand winter periods. For all scenarios, the year 2038 is notably affected by the retirement of firm baseload coal-to-gas generation units. This impact could be mitigated by adjusting the commercial operation dates of new generation facilities.

The ongoing electrification and decarbonization of the economy necessitates continuous monitoring of resource adequacy implications. The reliability results for the year 2038 warrant cautious interpretation. Sensitivity analyses suggest that resource adequacy modeling for future periods can be significantly influenced by minor variations in fundamental inputs. The assumptions in the 2024 LTO forecast encompass considerable uncertainty, necessitating ongoing monitoring and evaluation as energy transition, technological advancements, and regulatory frameworks evolve.

The AESO will persist in monitoring, evaluating, and communicating with stakeholders regarding the implications of changes to these and other variables. As improved information becomes accessible, AESO will provide timely assessments on future resource adequacy to support market information and further mitigate risks should they materialize.

2.6.3. Emissions

In each of the 2024 LTO scenarios, the majority of emissions reductions are observed between 2024 and 2030, with emissions levels stabilizing for the duration of the forecast period. Post-2030, the variance in projected emissions across different scenarios is minimal.

Notably, by 2035, emissions in the Decarbonization by 2035 scenario are projected to be 1.2 megatonnes (Mt) lower than those in the Reference Case. Conversely, the Alternative Decarbonization and High Electrification scenarios are expected to yield emissions slightly above the Reference Case, by 0.3 Mt and 0.5 Mt, respectively. This outcome is primarily driven by two factors: the increase in carbon pricing to $170 per tonne and the enhancements in the TIER high-performance benchmark for electricity, which are anticipated to incentivize numerous CCUS retrofitting projects on existing facilities and a considerable expansion in new wind and solar energy projects prior to 2030.

By 2035, forecast emissions across all scenarios are expected to represent a 94 per cent to 96 per cent reduction from 2005 levels, indicating a substantial decrease in emissions within Alberta's electricity sector. The carbon emissions from the electricity sector in all scenarios are projected to deviate from the Reference Case by less than two Mt per year throughout the 2024 LTO timeframe.

For more information, see the **Implications, Insights and Outcomes** on aeso.ca.

FIGURE 7: 2024 LTO Scenario Emissions

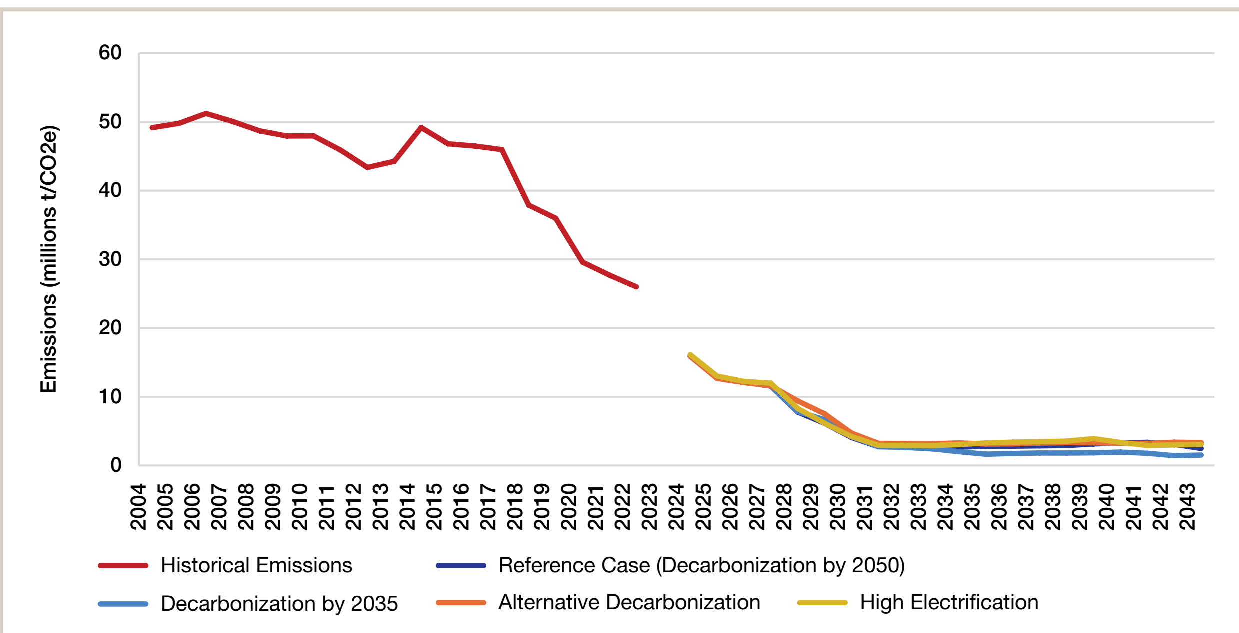
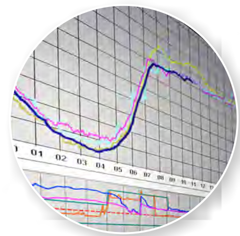


TABLE 2: 2024 LTO Reliability and Sustainability Metrics

Reliability (2038 Expected Unserved Energy)	**SCENARIO**	**Sustainability** (Total Scenario Emissions for Entire Forecast)
4,400 MWh	 **REFERENCE CASE**	**107.8** Mt
173,686 MWh	 **DECARBONIZATION BY 2035**	**96.4** Mt
19,833 MWh	 **ALTERNATIVE DECARBONIZATION**	**113.7** Mt
5,953 MWh	 **HIGH ELECTRIFICATION**	**116.0** Mt

Note: Primary differences between the LTO scenarios demonstrate that the Decarbonization by 2035 scenario exhibits the highest resource adequacy risk, by a significant margin, due to the restrictions imposed by the CER *Gazette 1* framework. Emissions in all scenarios represent a substantial decline from historical levels, with the lowest emissions resulting from the Decarbonization by 2035 scenario.

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