Module B Study:

Overview of Modeling Results and Key Findings

prepared for the Alberta Utilities Commission ("AUC")

in Proceeding 28542: AUC Inquiry into the ongoing economic, orderly and efficient development of electricity generation in Alberta

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1 Executive summary

In August 2023, the Alberta Government initiated an Inquiry into the impact of renewable generation on the reliability and affordability of electricity in Alberta

The Government of Alberta directed the Alberta Utilities Commission ("AUC") to launch an Inquiry into the impact of the growing level of renewable energy on the Alberta electricity system.[1] Specifically, the AUC was directed to examine changes in the generation supply mix, system reliability, and customer affordability as a result of the growth of renewable generation in the Alberta electricity market.[2]

London Economics International LLC ("LEI"), a global economic, financial, and strategic advisor in energy, water, and infrastructure, was hired to conduct a forward-looking analysis, in the context of the province's current wholesale market design and policy environment and leveraging data and analysis from the Alberta Electric System Operator ("AESO"). The forward-looking analysis began with two Base Case outlooks for the Alberta electricity sector over the next 20 years – one Base Case was designed to reflect federal draft Clean Electricity Regulations ("CER"),[3] referred to as the 2035 Base Case; the other Base Case is consistent with the province's Alberta Emissions Reduction and Energy Development Plan,[4] referred to as the 2050 Base Case. These Base Cases represent two different decarbonization policy pathways for the Alberta electricity sector – decarbonization by 2035 versus decarbonization by 2050. Additional scenarios were also analyzed layered on top of these two Base Cases – to test the impact of even more renewables (the More Renewables Cases) and to test the impact of demand shocks (the Lower Demand Cases). This report summarizes the results of that analysis.

More detail on the origins of this analysis can be found in Section 2.

Mandatory and voluntary efforts to decarbonize are impacting the Alberta electricity sector

Alberta has a real-time energy-only electricity market. Inherent in this electricity market design is the fact that the signal to attract further investments in generation lies entirely in investor expectations for energy prices (referred to as "Pool Prices" throughout this report). Furthermore, Alberta's existing electricity market framework does not mandate a specific quantity of new investment on a going forward basis or any system reliability requirements. The quantity and type of investment in new generation assets are ultimately determined by whatever market forces

[1] Government of Alberta. *Order in Council 171/2023.* August 2, 2023.

[2] After the Alberta government issued the order-in-council establishing the terms of reference for the Inquiry, the Ministry of Affordability and Utilities issued a press release and fact sheet that emphasized the government's interest in considering both affordability and reliability impacts to the grid from additional intermittent power sources. *See* Alberta Ministry of Affordability and Utilities. *AUC approvals pause for renewable projects: Minister Neudorf.* August 25, 2023.

[3] Government of Canada. *Canada Gazette, Part I, Volume 157, Number 33: Clean Electricity Regulations.* August 19, 2023.

[4] Government of Alberta. *Alberta emissions reduction and energy development plan.* April 2023 (updated January 2024).

can support. LEI conducted its forward-looking analysis and modeling based on this Alberta-specific market context and design.

Alberta, like many other jurisdictions around the world, is contending with the impact on its electricity market of external developments driven by government, business, and consumer commitments to decarbonizing the economy. The federal draft CER requires all electricity generation that falls under the CER requirements to be net zero by 2035, which would compel all fossil-fuel fired power plants to retrofit with carbon capture technology or face significant operational restrictions.

At the same time, due to corporate Environmental, Social, and Governance ("ESG") commitments, the presence of a functioning competitive electricity market, and Alberta's reputation as a relatively easy place to develop new generation projects, a large amount of new renewable energy projects have been built in recent years and continue to be planned. The construction of these projects does not depend solely on revenues from the Alberta wholesale electricity market. These dynamics are creating unique challenges in Alberta due to the small size of its electricity system, its energy-only electricity market design, and the lack of any reliability mandate as part of its electricity market.

More details on the Alberta market context can be found in Section 3.

LEI used simulation modeling to dynamically assess market outcomes over the next 20 years

LEI used its proprietary simulation-based modeling tools to analyze the impact of renewable energy generation on the reliability and affordability of Alberta's electricity system over the next 20 years. Simulation modeling is required because we cannot simply assume that supply and demand remain the same. Our modeling suite allows us to assess how different generation technologies perform operationally and economically in the market, and dynamically integrate those considerations to determine the future evolution of electricity supply.

This analysis is adapted to Alberta's specific and unique characteristics. LEI's wholesale market analysis includes strategic bidding to assess the impact of economic withholding. LEI considered external drivers to develop a variety of reasonable scenarios. LEI also analyzed the impacts of different weather conditions and generation outage patterns to understand the prospect for system reliability – supply adequacy – with the evolving supply mix.

Outcomes from LEI's wholesale energy modeling are also used to project total electric bills for a typical residential customer in Alberta, to assess the impact of increased renewables on affordability. We paired the outlook for the cost of electricity supply under each scenario with the likely evolution of transmission and distribution system costs to develop an estimate of total electric bills.

More details on the modeling methodology and assumptions can be found in Section 4.

Key findings

The electric grid will become less reliable: by the late 2030s, there is potential for unprecedented load shed in Alberta under the current electricity market design, regardless of the specific decarbonization policy pathway, because of insufficient supply

The current energy-only market design does not provide sufficient economic incentives to ensure electric system reliability in Alberta under the modeled conditions

Growing levels of renewable generation result in lower Pool Prices, dampening the investment signal under the current market design and causing system reliability to decline

Under all scenarios modeled, Alberta's electric system reliability performance worsens over the longer term. This result is based on the continuation of the current energy-only market design and associated policies, as well as implementation of decarbonization policies. Severe supply adequacy problems start to emerge in the mid-2030s. By the late 2030s, reliability risk under the 2035 Base Case is expected to be worse than the 2050 Base Case – although under both Base Cases, the level of reliability by the late 2030s would be materially worse than the level Albertans have been accustomed to. In the 5% most severe reliability events, nearly 10% of demand would not be met, with unserved load events that last for almost an entire day (23 hours). Supply adequacy problems emerge even sooner (in the next five years) if low Pool Prices motivate significant retirements of coal-to-gas units in the short term, without sufficient incremental new dispatchable resources (i.e., generation that can be effectively turned on when needed).

It is important to keep in mind that the forward-looking analysis is subject to technological risk. LEI's analysis relies on AESO's preliminary 2024 Long Term Outlook ("LTO") supply mix assumptions, which incorporate new generation technologies including hydrogen-based generation, carbon capture technology, and in the very long term, the installation of small modular nuclear reactors. LEI took these assumptions as a given and did not model the possibility of delays in construction or higher costs to construct, nor the possibility that these technologies would operate in a different way than currently expected. Although unquantified, these risks would put further pressure on supply adequacy and system reliability.

Furthermore, LEI finds that additional renewables exacerbate Alberta's electricity reliability problems around supply adequacy because they result in lower Pool Prices, which deteriorates the earnings of and dampens investment signals for other supply resources under the current market design.

More details on findings related to reliability can be found in Section 5.

Average Pool Prices will increase sharply in the late 2030s: Pool Price trends are driven by carbon policies and the costs of reliability events

Pool Prices rise over the 2024-2043 time horizon, driven by carbon costs as well as the cost of reliability events. At the top end, Pool Prices are estimated to grow from an average of $81/MWh in 2024 to $200/MWh by 2043 under the 2035 Base Case. The 2035 Base Case sees higher price increases than the 2050 Base Case due to the draft CER's stricter rules and accelerated net zero implementation timeframe. Additional renewables moderate these price increases but worsen supply adequacy.

More details related to findings on Pool Prices can be found in Section 6.

Residential customer electric bills are expected to outpace inflation in the later years of the forecast period, at a similar trajectory to forecasted Pool Prices

Despite higher electric bills, there is worsening service reliability as compared to today

Under all scenarios, residential electric bills are expected to increase much faster than inflation in the later years of the forecast period, largely driven by the increase in Pool Prices. Importantly, customers not only face these higher bills, but also receive a lower level of service reliability than they are accustomed to. However, such outcomes assume a continuation of the status quo – the current energy-only electricity market design and associated policies. Although outside the scope of LEI's study, we believe these outcomes could be averted with balanced and thoughtful modifications to the current electricity market design.

Additional renewables moderate electric bill increases through a decrease in Pool Prices, although those scenarios also require more transmission investment, muting the overall impact.

More details related to findings on residential customer bills can be found in Section 7.

Roadmap to more detailed information

This document is a high-level summary of LEI's analysis. LEI has compiled three Annexes that provide more detail on the modeling approach, the different scenarios analyzed, key underlying assumptions and inputs, and detailed modeling results and findings. A list of these Annexes is provided in Section 8.

2 AUC Renewables Inquiry and LEI's scope of work

2.1 AUC Inquiry to assess the impact of renewables on reliability and affordability

On August 2, 2023, the Government of Alberta issued a new regulation temporarily pausing approvals under Section 9 or 11 of the Hydro and Electric Energy Act in respect of a hydro development or power plant that produces renewable electricity.[5] Simultaneously, the Government of Alberta asked the AUC to conduct a public inquiry (the "Renewables Inquiry") and issue a report no later than March 29, 2024; the terms of reference for this Renewables Inquiry include a "*consideration of the impact the increasing growth of renewables has to both generation supply mix and electricity system reliability*" – this is the initial focus of LEI's study.[6]

On August 25, 2023, Minister Neudorf issued a press release and fact sheet on the Renewables Inquiry and Related Pause that emphasized the Government of Alberta's concern with both affordability and reliability impacts to the grid from additional intermittent power sources.[7] Thus, affordability became another focus of LEI's study.

The Inquiry terms of reference and the additional context from the Minister of Affordability and Utilities guided LEI's scope of work.

2.2 LEI's scope: analysis to focus on existing market design, leveraging AESO analysis

The AUC and LEI agreed to examine the Inquiry topics through the lens of Alberta's current energy-only electricity market design and existing policy framework.[8] Market design issues were outside the scope of LEI's study. As a result, LEI's modeling and analysis assumed the following:

- Market design consists of a single clearing price real-time energy-only market with simple price/quantity offers;[9]
- Pool Prices that are above marginal costs continue to be permitted, in order to provide an investment signal under the current market design;
- Real-time energy price is limited to a $0/MWh floor and $1,000/MWh cap;
- No day-ahead unit commitment; no start-up cost recovery guarantees; and
- The existing Transmission Regulation policy is maintained, such that LEI's modeling assumes an uncongested transmission system and continues to use a single clearing price for all generation producing energy in a given hour.

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[5] Government of Alberta. *Order in Council 172/2023.* August 2, 2023.

[6] Government of Alberta. *Order in Council 171/2023.* August 2, 2023.

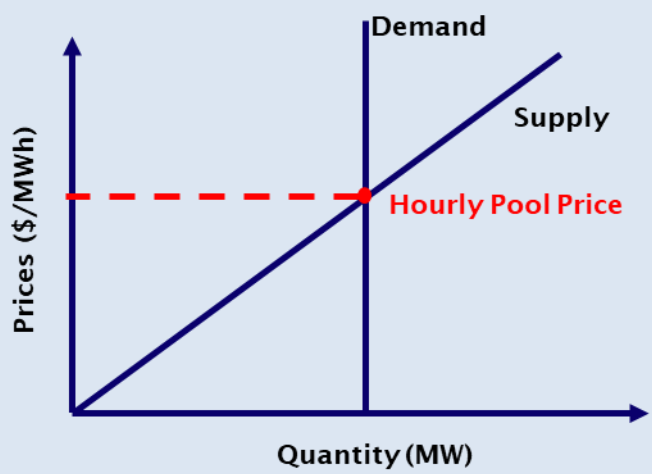
[7] Alberta Ministry of Affordability and Utilities. *AUC approvals pause for renewable projects: Minister Neudorf.* August 25, 2023.

[8] AUC. *Expert reports – scope of work (Exhibit 28542-X0004).* October 24, 2023.

[9] Ancillary services are procured separately through sequential auctions held day-ahead on the NGX platform.

How are hourly Pool Prices set in Alberta?

The Alberta wholesale market for electricity is a single-price, competitive energy market, in which market outcomes (e.g., price and dispatch of power plants) are determined by the intersection of demand and supply, subject to certain limitations, such as the price floor at $0/MWh and $1,000/MWh price cap. Generators offer to produce energy at a certain price. The generators' offers are the supply curve in the illustration below, while the vertical line reflects the electricity load on the grid that must be met (the demand). AESO, as the system operator, determines the most economic (least cost) dispatch of generators, based on their offers. This happens on a minute-by-minute basis, as demand and supply are constantly changing. The hourly average of the minute-by-minute prices is known as the hourly Pool Price. Generators that are producing electricity within a specific hourly interval get paid the Pool Price and buyers of electricity must pay the Pool Price.



In addition, the AUC requested that LEI leverage research and analysis conducted by the AESO. LEI used the AESO's load forecast, retirement schedule, and generation supply assumptions from its preliminary 2024 LTO released on November 15, 2023.[10] The AESO's preliminary 2024 LTO provided the first set of scenarios for LEI's analysis, representing two different decarbonization policy pathways:

- 2035 Base Case, which assumes compliance with the federal draft CER;[11] and
- 2050 Base Case, which is aligned with the province's Alberta Emissions Reduction and Energy Development Plan.[12]

LEI also developed additional scenarios to consider the impact of increasing renewables over time, and of demand shocks (i.e., unexpected changes in demand) that result in lower demand, as summarized in Figure 1 below.

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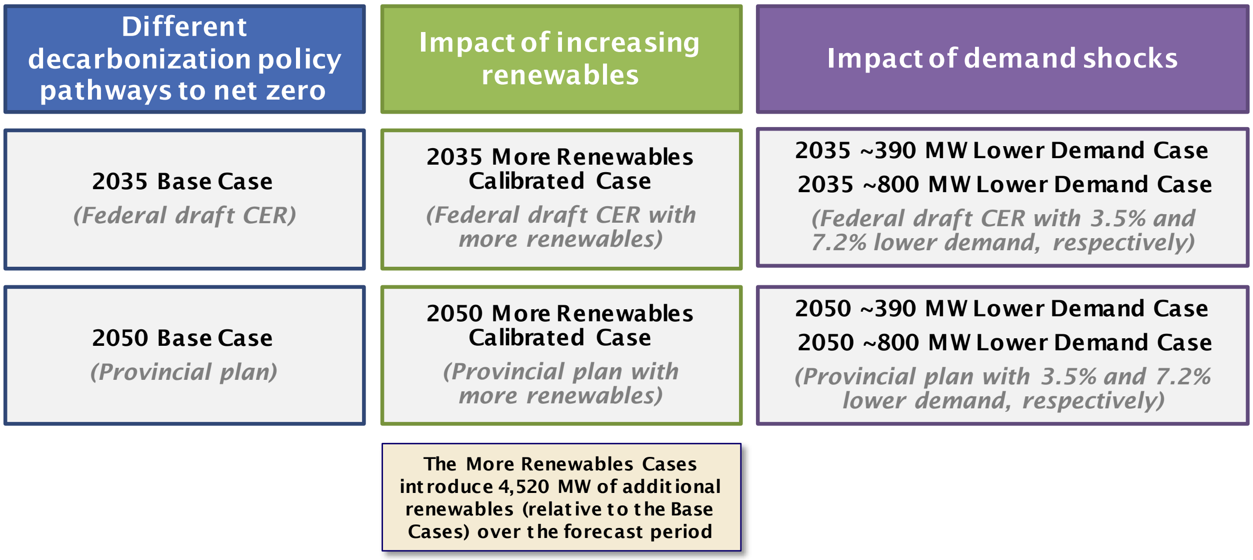
[10] AESO. *Forecasting Insights.*

[11] Government of Canada. *Canada Gazette, Part I, Volume 157, Number 33: Clean Electricity Regulations.* August 19, 2023.

[12] Government of Alberta. *Alberta emissions reduction and energy development plan.* April 2023 (updated January 2024).

Figure 1. Overview of scenarios in LEI analysis



Specifically, the More Renewables Calibrated Cases reflect two key considerations – first, the impact of additional renewables on market outcomes (i.e., lower Pool Prices), and second, the impact of those lower Pool Prices on other supply resources. Through financial analysis of modeled market outcomes, LEI found that the Alberta energy-only market would not be able to sustain as many non-renewable resources under the More Renewables Calibrated Cases as compared to the Base Cases. LEI also tested different weather profiles to assess supply adequacy. Assessing other dimensions of system reliability was out of scope for this analysis.

Details on the different scenarios and their underlying assumptions are available in Annex 1 *(Scenario Analysis: Long Term Weather-Normal Energy Market Forecast)*.

3 Mandatory and voluntary efforts to decarbonize are impacting market outcomes

Many electricity markets around the world are starting to adjust to government policies to decarbonize the economy, which includes reducing emissions from electricity sector generation as well as electrifying buildings and transportation. Alberta is no different.

The federal government issued its draft CER in August 2023,[13] which requires electricity generation that meets the CER applicability criteria to be "net zero" by 2035. According to the draft CER, the proposed regulations apply to all electricity generating units that:

a) have an electricity generation capacity of 25 MW or more;
b) generate electricity using fossil fuel; and
c) are connected to an electricity system that is subject to North American Electric Reliability Corporation ("NERC") standards.

These physically binding requirements would require any fossil fuel-fired facilities to retrofit using carbon capture technology or face significant operational restrictions.[14] Given that the province of Alberta has already negotiated the retirement or conversion of coal-fired facilities (with the last remaining coal facility slated for conversion to gas this year), the draft CER would mainly impact gas-fired generation. Currently, gas-fired generation represents over 59% of total capacity, and in recent years has produced 64% of annual energy transmitted on the Alberta Interconnected Electric System ("AIES").[15]

Concurrently, the province has experienced a large buildout of renewable energy capacity, as shown in Figure 2 below, driven in large part by the ease of building and operating merchant generation in Alberta, as well as the corporate interest in meeting ESG commitments. Many of these projects are not wholly dependent on revenues from Alberta's energy market. As a result, more than 6,000 MW of renewable capacity has been installed in Alberta since 2000, with another 3,395 MW under construction, 3,588 MW with regulatory approval from the AUC, and another 30,250 MW of projects that have either been announced, applied for connection to the AESO, and/or applied for regulatory approval, according to AESO's November 2023 Long-term Adequacy ("LTA") Report.[16] While renewable energy has no emissions, it can only generate electricity when the sun is shining, or the wind is blowing; this reliance on weather conditions can create volatility in the availability of resources to serve load from one hour to the next (and even on a sub-hourly basis). As the quantity of renewable generation grows, the magnitude of weather-related supply uncertainty is expected to increase.

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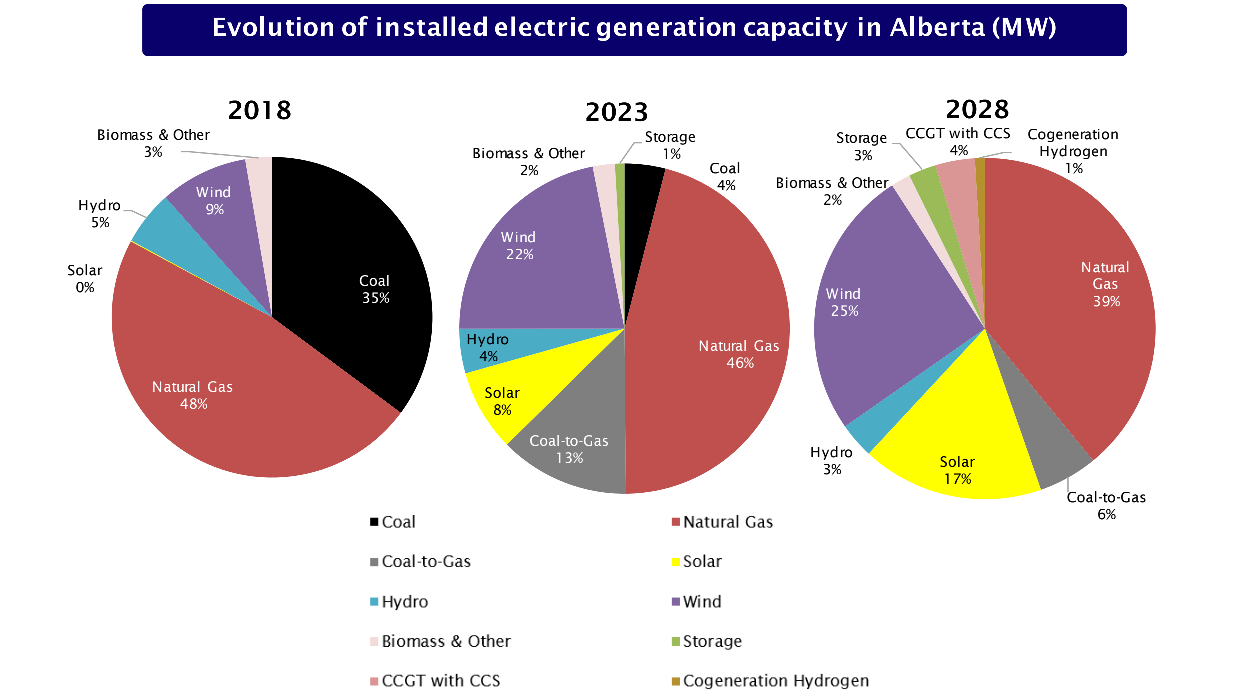
[13] Government of Canada. *Canada Gazette, Part I, Volume 157, Number 33: Clean Electricity Regulations.* August 19, 2023.

[14] Beginning January 1, 2035, new unabated fossil-fueled units will be limited in their operation to only 450 hours per year (approximately 5% of the unit's operating capacity), to meet additional generation requirements during periods of peak electricity demand. Existing units commissioned before January 1, 2025 are expected to align with the performance emissions standard by whichever comes first – January 1, 2035, or "following the unit's end of prescribed life," which is defined as 20 years after its commissioning date. (Source: Ibid).

[15] AESO ETS. *Current Supply Demand Report.* Last accessed February 1, 2024.

[16] AESO. *Long-term Adequacy Report.* November 9, 2023.

Figure 2. Evolution of installed electric generation capacity in Alberta



Sources: AESO. *Annual Market Statistics Reports – 2010 to 2019*; AESO. *Annual Market Statistics Tableau Dashboard.*

Alberta has several unique characteristics that make managing these developments challenging. First, it is a relatively small electricity market with a peak demand of 12,384 MW[17] and installed capacity of 20,777 MW,[18] with import limits on interconnections to neighbouring regions (none of which have an organized energy-only market), and challenges in arranging exports to markets further away.

Second, it has a relatively simple wholesale market design, with generators only earning revenues from selling energy in the spot market and capacity into the much smaller ancillary services markets (ancillary services are procured by the AESO to support the reliable operation of the grid on a day-ahead basis). As more renewables come online, LEI's modeling indicates that Pool Prices will more frequently end up at the price floor of $0/MWh, which will mean other generators that have to pay for fuel will be running in those hours at a loss. An increasing frequency of $0/MWh prices will challenge the economics for existing power plants and new dispatchable generation investments, given that the energy-only market (and associated ancillary services markets) are the only source of revenues under the province's current electricity market design.

Third, Alberta's current market design has no mandated reliability targets – which means that there is no mechanism in the market (outside of the Pool Price) to compensate generators for investing in new or expanded generation assets to ensure that there is reliable electricity supply – and no process for ensuring the orderly retirement of generators.

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[17] AESO ETS. *Historical Pool Price.* Last accessed February 1, 2024.

[18] AESO ETS. *Current Supply Demand Report.* Last accessed February 1, 2024.

4 LEI used simulation modeling to dynamically assess market outcomes over the next 20 years

4.1 LEI is an independent consultant with deep expertise in wholesale electricity sector modeling

LEI is a global economic, financial, and strategic advisory firm specializing in energy, water, and infrastructure. The firm combines a detailed understanding of specific network and commodity industries, such as electricity generation, transmission, and distribution, with sophisticated analysis and a suite of proprietary quantitative models to produce reliable and comprehensible results. LEI has worked extensively with policymakers as they deal with the energy transition due to the evolution of new technology, evolving consumer patterns, and new policy and reliability challenges. LEI has over 25 years of experience working in Alberta and with clients across the North American electricity sector. The firm has a balance of private sector and governmental clients, which informs and enables us to advise on the impact of regulatory initiatives on private investment, as well as predict the extent of possible regulatory responses to individual firm actions.

LEI has a suite of proprietary modeling tools developed and refined over decades for focused use in the electricity sector. Our modeling suite incorporates state-of-the-art statistical and game theoretic techniques for analyzing competitive wholesale markets, cost-of-service datasets for benchmarking and productivity trends, and practical and real-world financial models for advising clients on participation in complex markets and optimization of their use of electricity. Our tools are regularly relied upon by our clients to perform various market analyses or as inputs to financial and economic modeling.

4.2 Simulation modeling is used to embed economically rational investment and operational decisions over the 20-year timeframe

LEI used its proprietary simulation-based modeling suite to project future market outcomes and analyze the impact of renewable energy generation on supply adequacy and the cost of electricity over time. Simulation modeling is necessary because the Inquiry required an assessment of changes into the future – namely, the growth of renewables. We cannot simply assume that supply and demand remain the same. LEI completed the modeling over a 20-year timeframe, consistent with industry best practice.

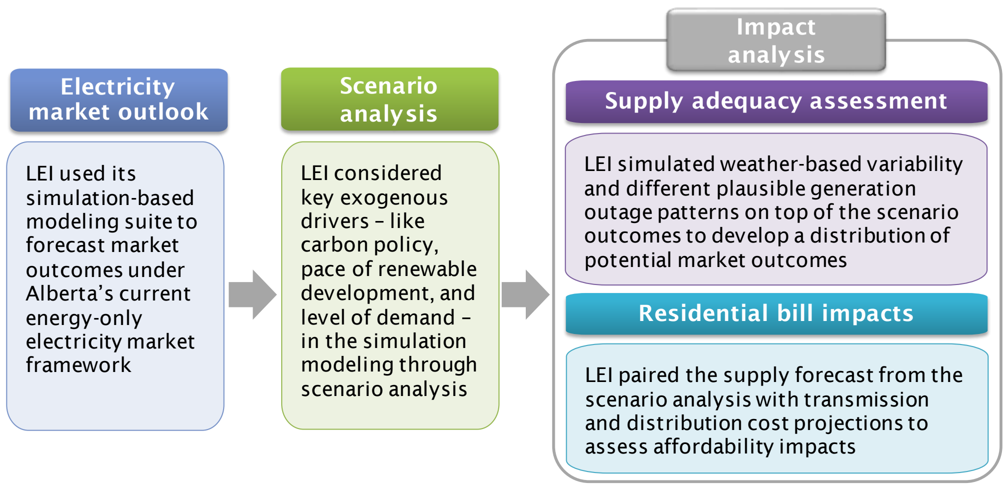
> ***What is simulation modeling?***
>
> Generally, a simulation model is intended to mimic real world dynamics. With respect to the electricity market, simulation modeling determines the dispatch of generating resources in the market (by assuming that the lowest cost generator is "dispatched" first in each hour) to meet projected hourly load, subject to technical assumptions regarding generation operating capacity and availability of transmission. This analysis will also produce a forecast of Pool Prices.

LEI's analysis entailed three separate phases:

- **Wholesale energy market modeling** to assess market price outcomes and impacts to the generation supply mix, assuming economically rational and competitive market-motivated investment decisions. LEI used a proprietary module to ensure that the critical features of the energy-only market (i.e., economic withholding) were incorporated into the forward-looking modeled conditions.

- **Scenario analysis** to test different external market drivers, such as carbon policy pathways, pace of renewable development, and level of demand.
- **Impact analysis** to evaluate the impact of these different scenarios on supply adequacy and on residential customer electric bills.

Figure 3. Overview of LEI's modeling approach



More information on LEI's modeling methodology can be found in each of the Annexes.

4.3 LEI leveraged AESO data and analysis to develop modeling assumptions

LEI used AESO's modeling and underlying assumptions from its preliminary 2024 LTO, including AESO's load forecast, supply projections (such as new investment and retirement), and information about the cost of new generation resources.

To assess residential electric bill impacts, LEI relied on AESO's 2022 Long-term Transmission Plan[19] and more recent announcements from AESO's 2023 Grid Reliability Update Stakeholder Information Session.[20] In addition, LEI layered in other assumptions as needed, such as additional transmission costs for scenarios with higher levels of renewables, based on AESO's 2022 Net-Zero Emissions Pathways Report,[21] as well as assumptions about distribution system costs associated with integrating increasing levels of solar distributed energy resources ("DERs") and electric vehicles ("EVs"), based on the recently released 2024 Net-Zero Analysis of Alberta's Electricity Distribution System.[22]

A detailed breakdown of LEI's assumptions and sources can be found in each of the Annexes.

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[19] AESO. *AESO 2022 Long-term Transmission Plan.* January 2022.

[20] AESO. *Grid Reliability Update Stakeholder Information Session.* November 23, 2023.

[21] AESO. *AESO Net-Zero Emissions Pathways Report.* June 2022.

[22] Guidehouse (prepared for the AUC). *Net-Zero Analysis of Alberta's Electricity Distribution System.* January 22, 2024.

5 Key finding: supply adequacy and system reliability will deteriorate

Supply adequacy and system reliability are critical components of any electricity system. Many use the term "reliability" as a catch-all, but there is a nuanced difference. Supply adequacy focuses on having enough electricity generation supply to meet hourly demand, taking into account planned and unplanned outages and other factors that may impact demand or supply. System reliability is broader and includes elements such as inertia and frequency support.

> ***What is supply adequacy?***
>
> Supply adequacy is having enough electricity generation supply to meet hourly demand, taking into account planned and unplanned outages and other factors that may impact demand or supply.

In other words, supply adequacy is a component of system reliability. Other components of system reliability include the ability to continuously balance supply and demand and maintain adequate inertia and frequency on the grid. Therefore, supply inadequacy is one cause of poor system reliability. LEI's analysis was limited to supply adequacy.

5.1 Current market design and policy will result in worsening supply adequacy

LEI analyzed the Base Cases and additional scenarios to determine supply adequacy outcomes. Specifically, we estimated the average size of unserved load (in MWh or % of annual demand not met), which is the amount of demand that is not served when the system runs out of available supply to provide electricity to all customers. As a result, the AESO would have to shed some load – which means that some customers will not have electricity for some period of time. In the industry, this is sometimes also referred to as a "rolling blackout".[23]

> ***What is unserved load?***
>
> Unserved load refers to instances where not all customers' electricity demand can be met, regardless of price.

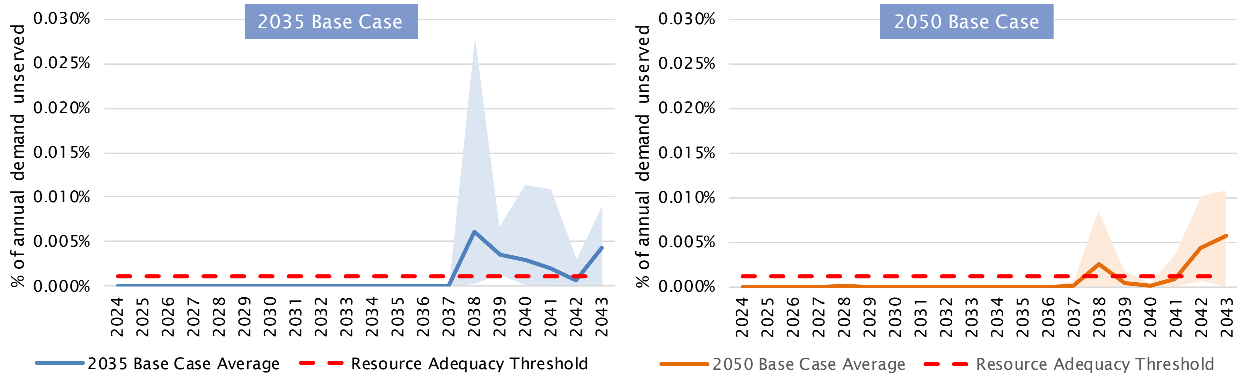
Supply adequacy worsens over time across all scenarios tested by LEI. The growing levels of intermittent renewables and decreasing amounts of dispatchable thermal generation (i.e., generation assets that can be "dispatched" at will and do not depend on weather conditions) amplify the frequency and magnitude of unserved load events. Figure 4 below shows that these supply adequacy problems start to become significant in the mid-2030s, even with "normal" weather.[24] By the late 2030s, reliability risk under the 2035 Base Case is expected to be worse than the 2050 Base Case – although under both cases, the level of reliability by the late 2030s would be at a level materially worse than what Albertans have been accustomed to, as indicated by the modeled unserved energy crossing above the AESO's Resource Adequacy Threshold (shown as the red dotted lines in the charts below). The AESO has not had to implement rolling backouts

[23] A rolling blackout entails the system operator intentionally cutting electricity to some customers in order to balance supply and demand. A rolling blackout is therefore a partial outage of the electric system – in contrast with a system-wide blackout, where the entire system is on outage.

[24] LEI used actual weather data in its long term energy market modeling, in order to ensure realistic conditions. LEI chose to use 2021 weather conditions (which impacted hourly renewable generation and hourly variation in load) to represent "normal" weather, because 2021 conditions were closest to longer term averages and were neither mild nor abnormally extreme in terms of weather factors that could skew the scenario analysis results towards low likelihood events.

since 2013. Moreover, the level of load shed projected far exceeds anything actually observed in the modern history of the electric grid in Alberta.

Figure 4. Comparison of levels of demand unserved under the Base Cases with normal weather



Notes:

- LEI ran its simulation model 10 times (seeds) for each year and scenario, with varying patterns of generation outage schedules. The shaded areas in the charts above represent the range of modeled outcomes caused by these different patterns of generation outages. The solid lines represent the average across the 10 seeds.

- AESO defines the Resource Adequacy Threshold as the 1-hour average Alberta internal load for a year divided by 10. Converting to percentage terms is calculated as 1/8760/10 = 0.00114%.

What are the Supply Adequacy Shortfall Metric and Resource Adequacy Threshold in Alberta?

While the Alberta energy-only electricity market has no mandated reliability targets, the AESO is still required to report on long-term (2 year) resource adequacy metrics on a quarterly basis. If the AESO identifies a two-year probability of supply adequacy shortfall, the AESO may take specific preventative actions, including procuring load shed services, back-up generation, or emergency portable generation.

The AESO also develops a Long Term Outlook every two years to forecast electricity demand and generation over a 20-year horizon to inform its long-term plans. The LTO monitors resource adequacy through a Resource Adequacy Threshold. This analysis is conducted for information and planning purposes only – there is no mechanism for the AESO to procure new generation even if reliability risk is found to exceed the threshold.

LEI has presented its analysis using the same metrics and AESO's current benchmark for acceptable reliability in Alberta.

LEI used a probabilistic analysis to also assess how weather would further interact with varying generation outages. Further analysis of unserved load events indicates that, in the 5% most severe reliability events, an average of 10% of demand would not be met; similarly, the 5% worst long-duration unserved load events would last for almost an entire day on average.[25] The system is projected to have the highest reliability risk during evening hours in the winter months. This would be an unprecedented amount of load shed that Albertans have not experienced before.

This deterioration in supply adequacy is driven by the supply mix assumed in the AESO's preliminary 2024 LTO, which indicates that Alberta's energy-only market will not provide a sufficiently robust signal for additional investment in new dispatchable generation capacity.[26]

Historically, Alberta's energy-only market design, which allows generators to offer bids above their theoretical short-run marginal costs,[27] created a robust enough signal for investment needs. This negated the need for supply adequacy requirements or reserve margin mandates in Alberta to ensure that the grid had enough electric generation capacity to meet hourly demand.

However, Alberta's market design is coming under pressure from the impact of two different developments: proposed environmental policies calling for a 'net zero' mandate for electricity – which will require fossil-fuel fired generators to retrofit or face significant operational restrictions – and corporate interest in ESG – which is dramatically increasing the development of renewable generation, independent of market price signals. Renewable generation provides clean energy, but the production of that clean energy is not perfectly aligned with when consumers want their electricity, nor can renewable generators control when (and in what quantities) they produce electricity, creating an ongoing need for dispatchable generation.

As a result, the electricity system, absent market design changes, will become less reliable than it has been historically. LEI's analysis shows that the current compensation in Alberta's energy-only market – the Pool Price for energy – may not be sufficient to remunerate dispatchable generators for their fixed costs and to prevent premature retirements or sustain a level of needed incremental investment.

LEI identified that the provincial plan for decarbonization (modeled as the 2050 Base Case) produces better supply adequacy outcomes than the federal draft CER (2035 Base Case) in most years. This is primarily because the provincial plan does not limit the number of hours that unabated gas generation units can run in a year, whereas the federal draft CER limits these units to a maximum of 450 hours of operation per year. The provincial plan thus allows natural gas

[25] As a point of reference, Storm Uri in 2021 resulted in an estimated load shed of up to 26% of demand in Texas, lasting for approximately 72 hours.

[26] LEI's simulation model tracks the revenues earned and costs incurred by generation assets in the energy market. LEI compared the forecast of net profits (after taking into account fixed operating and maintenance ("O&M") costs) of the generation assets against the capital costs. The results confirm AESO's findings that additional investment cannot be supported by the forecast market prices. In addition, LEI's modeling shows that under the forecast conditions, dispatchable new generation is generally not earning a robust return on investment expected for merchant generators until the late 2030s. See Annex 1 *(Scenario Analysis: Long Term Weather-Normal Energy Market Forecast)* for more details.

[27] Short-run marginal costs ("SRMCs") consist of costs associated with an incremental unit of energy supplied. The largest component of the SRMC for fossil fuel-fired power plants is typically fuel costs (e.g., coal or natural gas prices multiplied by the thermal efficiency of the generating unit in question). The SRMC also contains other non-fuel variable O&M expenses, such as consumables used by the facility's operations to generate the energy, as well as costs associated with carbon emissions.

generators to provide better support to the grid when intermittent renewable generation output is low, or when there are outages of many generation units.

One important caveat is that LEI's analysis does not consider technology risks associated with the new generation technologies assumed in AESO's preliminary 2024 LTO, including hydrogen-based generation, natural gas-fired generators retrofitted with carbon capture technologies, and small modular nuclear reactors. AESO's preliminary 2024 LTO analysis assumes significant investments in these technologies, which have not yet been proven on a commercial scale in Alberta or in any other jurisdiction. LEI has not investigated the feasibility of the construction schedules assumed in AESO's supply forecast. LEI has also employed AESO's capital cost assumptions in completing its financial analysis on the economics of investment. Furthermore, LEI assumed that these new technologies will have the same level of reliable operation as existing natural gas-fired or nuclear units. However, if these new technologies are in fact less reliable than LEI assumed, more costly, or likely to be materially delayed beyond their projected in-service dates, then the level of supply adequacy risk would be worse than projected in LEI's modeling.

5.2 Additional renewables exacerbate supply adequacy problems by squeezing out dispatchable generation

These supply adequacy problems are exacerbated if more renewable generation is built than what is assumed in the Base Cases. More renewable energy capacity creates a higher frequency of $0/MWh Pool Price incidents, as shown in Figure 5 below. This reduces the profitability of thermal generators, with existing thermal generators more likely to retire and potential new thermal generators less likely to enter the market. Fewer dispatchable generators creates more supply adequacy concerns. For example, in the 2050 More Renewables Calibrated Case, 125 MW of gas-fired units that would have entered the market under the 2050 Base Case are no longer economically viable, as their pre-tax returns would be in the low single digits, too low for investors to consider. Moreover, this increases the province's vulnerability to weather, where lower levels of wind or solar irradiation will have a bigger impact on the electricity system.

Figure 5. Number of hours with Pool Prices at zero under normal weather conditions

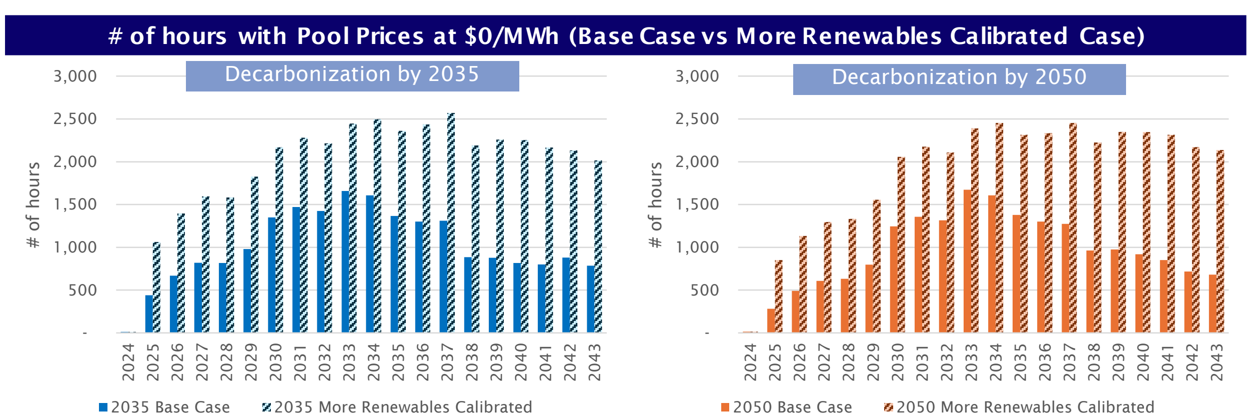
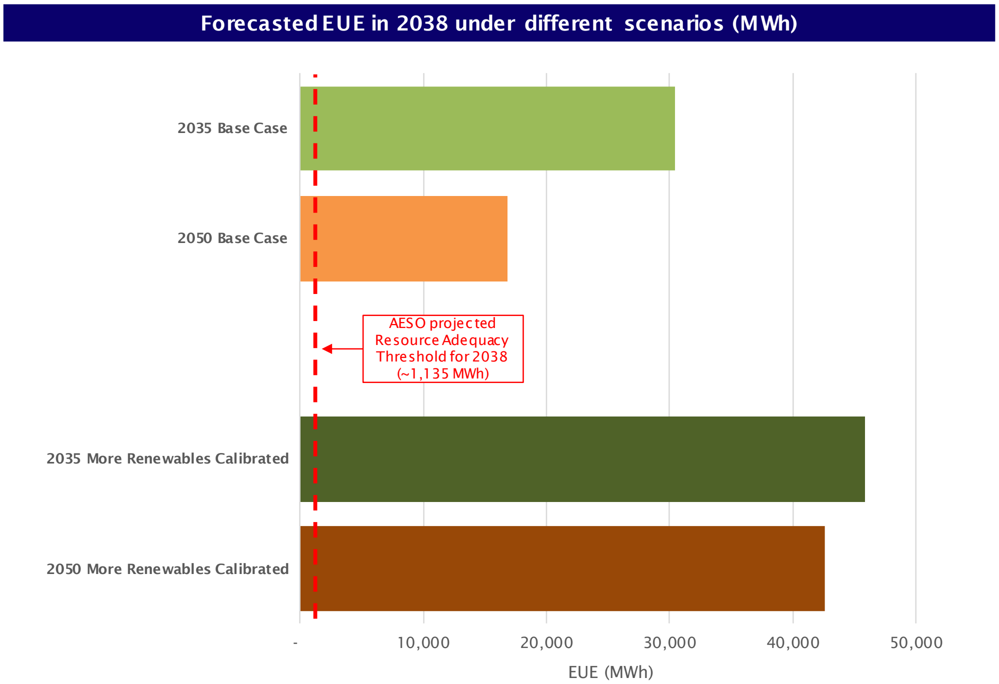


Figure 6 below compares the forecasted expected unserved energy ("EUE") under the various scenarios for the year 2038 (after all coal-to-gas units are expected to retire) relative to the AESO's Resource Adequacy Threshold for the same year (see red dotted line). With higher renewables, the modeled EUE exceeds 40,000 MWh, as compared to ~10,000 MWh under the 2050 Base Case and ~30,000 MWh under the 2035 Base Case, in all cases significantly higher than the AESO's Resource Adequacy Threshold of ~1,135 MWh. As compared to the Base Cases, the cases with higher renewables are expected to have more frequent, longer duration unserved load events, with more MWs of unserved load on average (i.e., more consumers being affected).

Figure 6. Expected unserved energy under Base Cases vs More Renewables Calibrated Cases for 2038



5.3 Retirements of older coal-to-gas units in the near term may exacerbate grid reliability under abnormal weather conditions

LEI observes that there are higher amounts of unserved energy under both Base Cases once coal-to-gas units start to retire, which may be as early as 2025, under certain abnormal weather conditions.

Two near-term coal-to-gas retirement schedules were considered, consistent with the AESO's supply projections. First, under the 2035 Base Case, 2.2 GW of coal-to-gas units were assumed to retire before 2025; second, under the 2050 Base Case, a higher level of coal-to-gas unit retirements was assumed – 2.6 GW before 2025. In both cases, 2 GW of new dispatchable resources were added, consistent with the AESO's supply projections. Under the 2050 Base Case (the scenario with more coal-to-gas retirements), LEI's analysis projects EUE that breaches the AESO's thresholds as early as 2025, indicating a higher risk of load shed under abnormal weather. Specifically, modeled EUE reaches 2,450 MWh in 2025, which exceeds both AESO's Long-Term Resource Adequacy Threshold of 1,135 MWh, and AESO's Two-Year Probability of Supply Adequacy Shortfall Metric of 2,005 MWh from the November 2023 LTA Report. Once additional investment comes online, the projected EUE declines below the thresholds.

This observation implies that significant retirements may – at least temporarily – result in deteriorating supply adequacy to levels that may not be acceptable.

6 Key finding: average Pool Prices are expected to increase

6.1 Average Pool Price increases are driven by decarbonization policies

Average Pool Prices increase over the modeling time horizon, primarily due to two factors. First, carbon costs guided by decarbonization policies increase Pool Prices. Thus, due to the more stringent carbon emissions limitations of the federal draft CER, Pool Prices are higher under the 2035 Base Case than the 2050 Base Case.

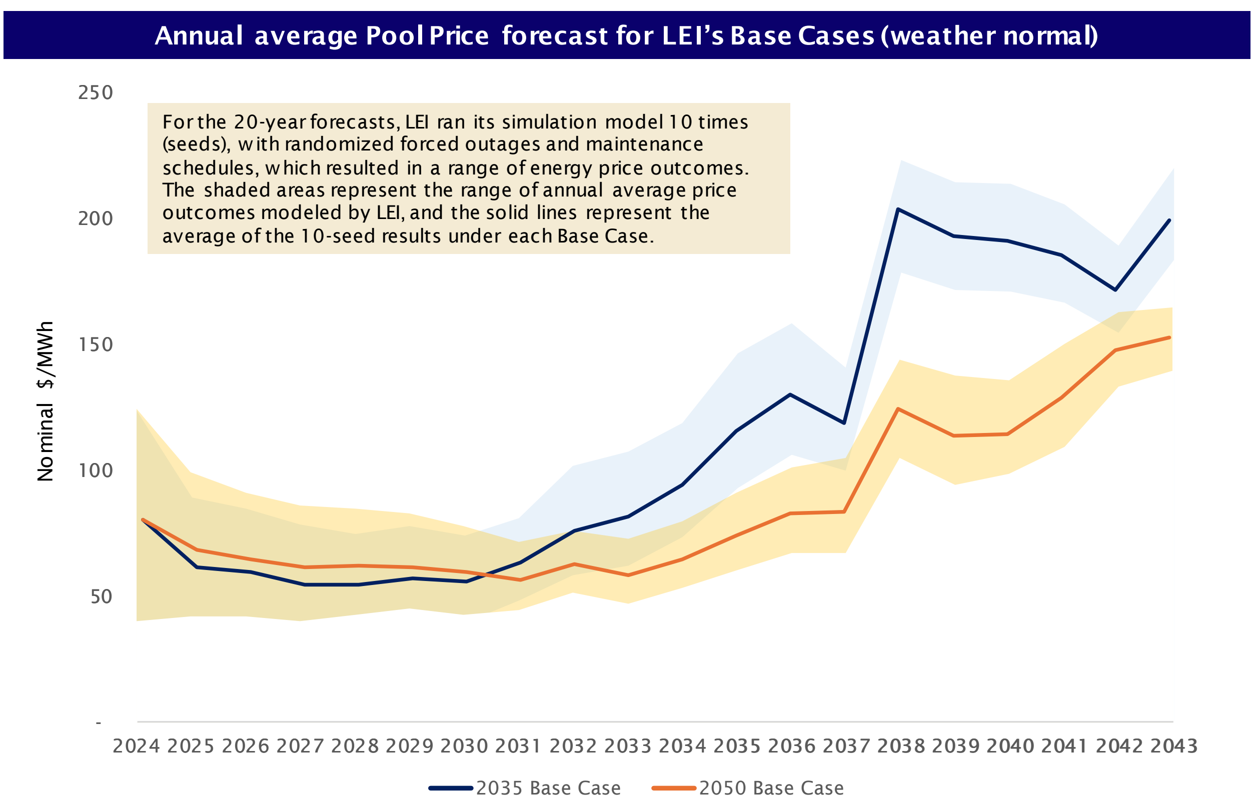
How do the federal draft CER and provincial plan differ?

There are two primary differences. First, the federal draft CER pursues decarbonization by 2035, whereas the provincial plan pursues decarbonization by 2050. Second, the federal draft CER sets more stringent carbon emissions limitations – unabated gas generation units can only run up to a maximum of 450 hours per year; the provincial plan does not have a similar limitation.

Second, Pool Prices become more volatile over time, with more frequent price spikes and zero prices due to renewables coupled with a tightening capacity reserve margin. The price spikes, in some hours, are the result of load shed due to supply inadequacy, as discussed in Section 5.

This long-term increase in Pool Prices exceeds inflation after 2030, but is still not sufficient to support the level of electric system reliability that Albertans have been used to (as discussed in Section 5).

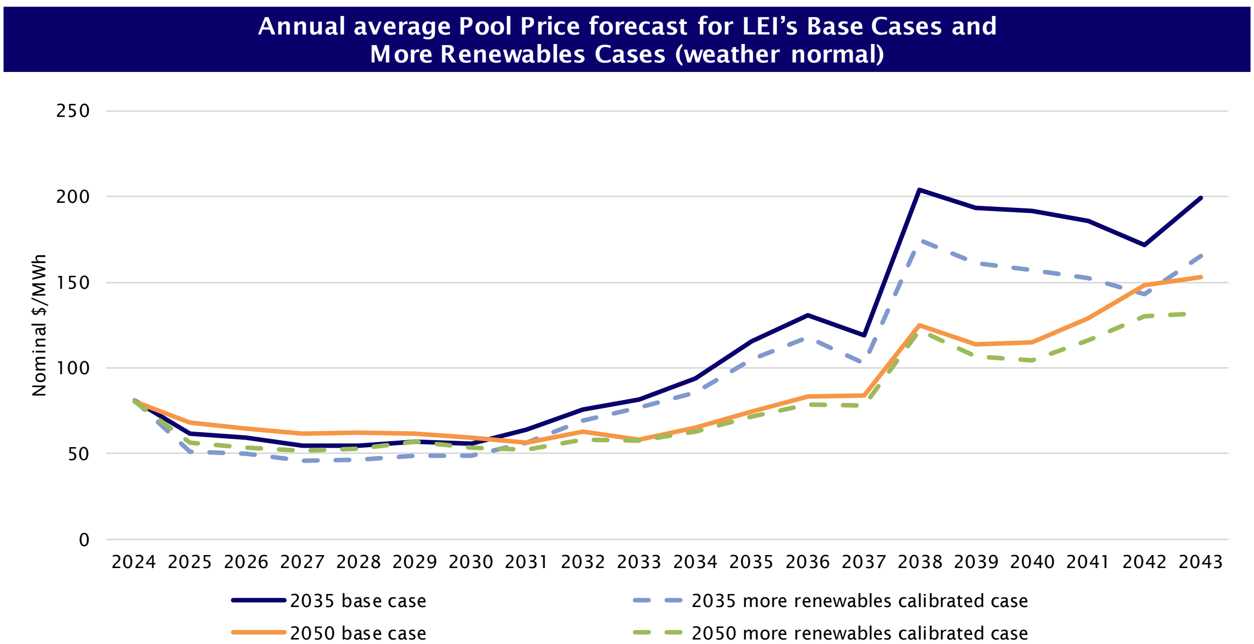
Figure 7. Comparison of Pool Price forecast under 2035 and 2050 Base Cases



6.2 Additional renewable capacity will decrease Pool Prices

Intermittent renewables such as wind and solar offer their energy at $0/MWh in the energy market. Therefore, additional renewable capacity will put downward pressure on forecast Pool Prices. In turn, this reduces the profitability of thermal generators, with existing thermal generators more likely to retire and potential new thermal generators less likely to enter the market. Thus, the system becomes more prone to price spikes (due to increasing weather scarcity events and unserved energy events) and more frequent zero prices. The impact on Pool Prices due to additional renewable capacity is illustrated in Figure 8 below. While the annual average Pool Prices are lower with additional renewable capacity, the system is also less reliable (as discussed in Section 5.2).

Figure 8. Pool Prices assuming more renewable capacity

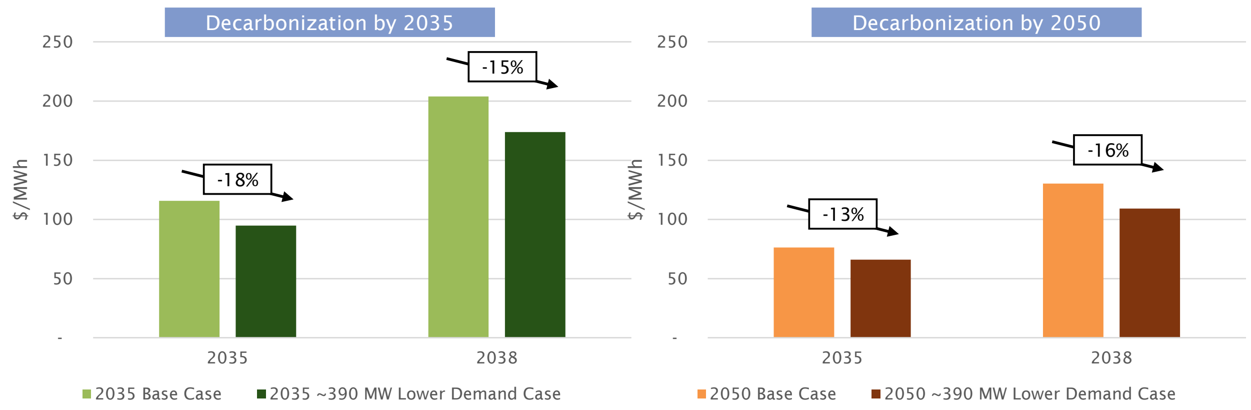


6.3 Relatively small changes in demand have a large impact on Pool Prices

Fairly small changes in demand have a profound impact on Pool Prices because we are assuming very tight supply-demand conditions in the longer term, much tighter than what we have experienced in the last 20 years in Alberta. Lower demand reduces average Pool Prices by a greater amount than the percentage change in demand, as illustrated in Figure 9 below.[28] Under the 2035 Base Case, when demand is decreased by 3.5%, annual average Pool Prices decrease by 15% to 18%. Similarly, under the 2050 Base Case, 3.5% lower demand decreases annual average Pool Prices by 13% to 16%.

[28] LEI ran the Lower Demand Cases for 2035 and 2038 only.

Figure 9. Change in annual average Pool Prices due to ~390 MW (-3.5%) lower demand in 2035 and 2038



At the same time, lower demand leads to improvements in supply adequacy, as there are fewer hours where there is insufficient supply to meet this lower demand. The decrease in the number of hours with unserved load (with $1,000/MWh hourly Pool Prices) contributes to the reduction in annual average Pool Prices.

The modeling results from the scenarios with lower demand highlight the importance of potential flexible demand-side resources in an energy-only market. By holding the supply mix constant and observing how lower demand results in improved supply adequacy, we estimate that between 850 to 1,200 MW of additional dispatchable demand-side resources by 2038 could reduce unserved energy events to levels within the AESO's forecasted Resource Adequacy Threshold.[29]

[29] Assuming these additional dispatchable demand-side resources are available at all times and can be dispatched when needed.

7 Key finding: residential electric bills increase in line with Pool Prices

7.1 Residential electric bills outpace inflation in the later years of the forecast period – while reliability is reduced

> ***How to assess affordability?***
>
> Affordability is not an economic term, it is a subjective term. Thus, LEI used inflation as a yardstick to compare the projected electric bill impacts against.

LEI compared the projected increase in residential electric bills to inflation as a proxy for assessing "affordability." Under all scenarios, residential electric bills are expected to rise above the rate of inflation in the later years of the modeled time horizon, closely tracking the trajectory of Pool Prices under the various scenarios. Residential electric bills increase the most under the 2035 Base Case, with a province-wide average compound annual growth rate ("CAGR") of 1.9% per year from 2025 to 2030 and then a much higher CAGR of 6.8% per year from 2030 to 2040. Under the 2050 Base Case, increases are more moderate: residential electric bills province-wide rise by a CAGR of 1.6% per year from 2025 to 2030 and 4.3% per year from 2030 to 2040. In contrast, LEI's inflation assumption for 2024 to 2040 averages 2.0% per year, consistent with AESO's long-term inflation assumption.[30]

The biggest driver of rising electric bills is the energy supply component, not the cost of transmission and distribution. However, there is some uncertainty about the amount of future transmission and distribution investments needed to accommodate increased renewables, solar DERs, and EVs. In addition, in rural service territories like ATCO, the wires portion of a typical residential electric bill is already relatively high.

Importantly, these higher electric bills correspond to a lower level of electric system reliability than Albertans have been accustomed to (as discussed in Section 5).

Details on this and other observations are available in Annex 2 *(Projection of Residential Electric Bills)*.

7.2 More renewable capacity will lower residential electric bills but make service even less reliable

With additional renewables, residential electric bills are projected to be lower than in the Base Cases, although the impact of lower Pool Prices is somewhat offset by the larger transmission investments needed to enable that renewables development. Under these higher renewables cases, residential electric bills under the 2035 More Renewables Calibrated Case are projected to increase at a CAGR of 2.6% per year from 2025 to 2030 and 6.2% per year from 2030 to 2040; residential electric bills under the 2050 More Renewables Calibrated Case are projected to increase at a CAGR of 2.4% per year from 2025 to 2030 and 4.2% per year from 2030 to 2040. This is

[30] For 2024-2026, LEI's inflation assumption is based on the average Alberta Consumer Price Index ("CPI") forecasts from the big five banks and the Government of Alberta; for 2027 onwards, LEI assumed 2% inflation, consistent with the AESO's long-term inflation assumption. See Annex 2 *(Projection of Residential Electric Bills)* for more details.

illustrated in Figure 10 below. However, as discussed in Section 5, more renewable capacity makes Alberta's electric grid even less reliable.

Figure 10. Comparison of change in projected monthly residential electric bills under various scenarios

Projected residential electric bill CAGRs by DFO and scenario

2035 Base Case
(Federal draft CER)

DFO	2025-2030 CAGR	2030-2040 CAGR
ATCO	2.1%	5.5%
EPCOR	1.9%	7.4%
ENMAX	1.6%	7.7%
Fortis	1.9%	6.7%
Province avg.	**1.9%**	**6.8%**

2035 More Renewables Calibrated Case
(Federal draft CER with more renewables)

DFO	2025-2030 CAGR	2030-2040 CAGR
ATCO	2.6%	5.0%
EPCOR	2.7%	6.7%
ENMAX	2.5%	7.0%
Fortis	2.7%	6.1%
Province avg.	**2.6%**	**6.2%**

2050 Base Case
(Provincial plan)

DFO	2025-2030 CAGR	2030-2040 CAGR
ATCO	1.9%	3.7%
EPCOR	1.6%	4.6%
ENMAX	1.3%	4.7%
Fortis	1.7%	4.1%
Province avg.	**1.6%**	**4.3%**

2050 More Renewables Calibrated Case
(Provincial plan with more renewables)

DFO	2025-2030 CAGR	2030-2040 CAGR
ATCO	2.4%	3.6%
EPCOR	2.4%	4.5%
ENMAX	2.2%	4.5%
Fortis	2.4%	4.1%
Province avg.	**2.4%**	**4.2%**

Note: LEI presents CAGRs for 2025-2030 and 2030-2040, as 2030 is the year where Pool Prices begin to diverge between the various scenarios (as shown in Figure 8 in Section 6.2).

8 Roadmap to more detailed information

LEI provides three Annexes with more detailed information on the inputs employed and modeling results. Each Annex provides detail on the modeling approach, the different scenarios analyzed, key underlying assumptions and inputs, and modeling results and findings.

The three Annexes are:

- **Annex 1 – Scenario Analysis: Long Term Weather-Normal Energy Market Forecast** presents the 20-year modeling exercise conducted by LEI for the various scenarios (Base Cases, More Renewables Cases, and Lower Demand Cases) assuming normal weather;
- **Annex 2 – Projection of Residential Electric Bills** presents LEI's approach to estimating electric bills by distribution facility owner ("DFO") for a typical residential customer under the various scenarios; and
- **Annex 3 – Probabilistic Supply Adequacy Analysis** presents the probabilistic analysis conducted by LEI that introduces weather-based variability to test the impact on supply adequacy.