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London Economics International LLC

Module B Study – Annex 1
Scenario Analysis: Long Term Weather-Normal Energy Market Forecast

prepared for

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

February 7, 2024

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Agenda

1	**Modeling approach**
2	Key assumptions and inputs
3	Key modeling results

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LEI conducted forward-looking simulations of the Alberta power market using a scenario-based approach, in order to estimate future supply adequacy and a typical residential customer's electric bill

Wholesale electricity market outlook

LEI used its simulation-based modeling suite to forecast market outcomes under **Alberta's current energy-only market framework** – leveraging information from AESO's preliminary 2024 Long-term Outlook ("LTO")

Scenario analysis

LEI considered key exogenous drivers – like carbon policy, pace of renewable development, and level of demand – in the simulation modeling through scenario analysis and sensitivities

Focus of this Annex

Impact analysis

Probabilistic assessment of reliability

To assess supply adequacy*, LEI simulated weather-based variability and different plausible generation outage patterns on top of the scenario outcomes to develop a distribution of potential market outcomes

Total electric bill impacts

LEI paired the supply forecast emerging from the scenario analysis with transmission and distribution cost projections to assess affordability impacts for residential customers

** LEI's terms of reference focus on supply adequacy, notwithstanding other dimensions of system reliability.*

LEI's proprietary tools provide the necessary functionality for an accurate representation of Alberta's electricity market

Simulation-based dispatch model that projects a single market-clearing price for each hour

POOLMod

- LEI's proprietary simulation dispatch model
- Consists of several key algorithms, such as maintenance scheduling, assignment of stochastic forced outages, hydro shadow pricing, commitment, and dispatch

Above SRMC offer behaviour provides an investment signal under the energy-only market

ConjectureMod

- Game theory module within POOLMod for the Alberta market
- Projects above short-run marginal cost ("SRMC") offers, replicating real-world outcomes; offers will be dynamic and change daily with evolving market conditions

Probabilistic assessment of weather-related factors

WeatherMod

- Assesses reliability and resource adequacy and tests the resiliency of the system to plant outages and varying weather conditions
- Allows for stochastic variation of generation outages, and consideration of weather patterns and their impact on load, intermittent renewable generation, as well as unplanned outages

Focus of this Annex

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Key facets of the simulation-based modeling were selected to comply with the overarching study goals in the timeframe allotted, while maintaining the necessary analytical rigor

Reflect the current energy-only market design and associated policies

Leverage existing relevant studies and analysis

Simulation of future supply mix

Completion by the deadline imposed by Government

Consideration of a range of scenarios

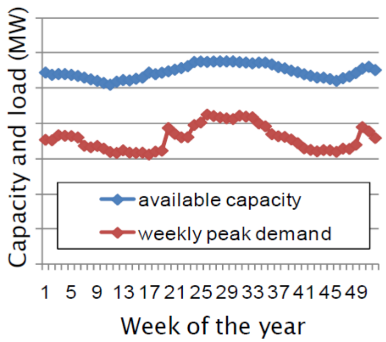
LEI's modeling and analysis assumed the following:

- market design consists of a **single clearing price real-time energy-only market** with simple price/quantity offers
- **offers 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**
- 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

POOLMod, LEI's proprietary electricity market simulation model, forecasts availability of resources, then simulates dispatch of resources to meet projected demand and set hourly Pool Prices

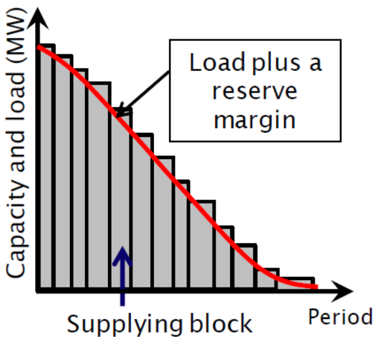
POOLMod employs a three-stage simulation process:

1 Weekly
Maintenance schedule



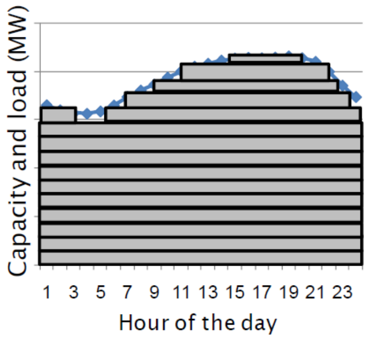
- A hypothetical, plant-specific maintenance schedule is determined on a weekly basis
- In general, more plants are scheduled on maintenance during months with lower demand

2 Daily
Commitment



- Hours in the day are sorted from highest to lowest load and available resources are ranked/matched
- On a daily basis, the ConjectureMod algorithm develops economically rational above SRMC offers for assets controlled by key market participants
- POOLMod creates an energy merit order based on offers from available resources

3 Hourly
Dispatch



- Dispatch occurs on a chronological hour-by-hour basis based on energy merit order, taking into account forced outages, intermittent generation, technical features of thermal plants (min. stable, etc.), intra-day constraints, inter-day information on stored energy and scheduled maintenance, and the offer strategy developed using ConjectureMod

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ConjectureMod, LEI's game theory module, models market participant bidding behaviour dynamically with evolving market conditions

Process diagram

1. Modeler defines "strategy space" and marginal cost baseline

ConjectureMod

2. Test offers <u>above</u> marginal costs for each day for a generation owner, in search of a higher profit

Multiple iterations to identify local equilibrium

POOLMod

3. Simulate dispatch and market clearing price based on identified offers above SRMC

On a daily basis, ConjectureMod estimates economically rational bids above marginal costs for each generation owner that reflects the availability of its resources, daily peak demand conditions, and total supply offers from competitors

POOLMod (including ConjectureMod) is run 10 times for each scenario to assess the range of potential outcomes with varying maintenance schedules, forced outages, and bidding behaviour

- **While WeatherMod is not used for the results covered in this Annex, there are still variables in POOLMod and ConjectureMod that impact simulated results, even under identical supply mix, demand, and fuel price settings**

- **These variables are randomized in each POOLMod "seed" run**

Maintenance schedule	Forced outages	Offer behaviour
• Each unit has a required # of weeks per year for maintenance • There are many combinations of maintenance schedules that can satisfy the requirements of the units • In each "seed", POOLMod chooses a different maintenance schedule	• Each unit has its own forced outage rate • The forced outage rate determines the probability that a unit is on outage in each day • POOLMod uses a randomizer to determine whether a unit is on outage on a daily basis	• The strategy space for economic withholding for each market participant is very large – multiple solutions (equilibria) • ConjectureMod uses an iterative process to test different offer strategies until it identifies a convergence point

- **In this Annex, we show the modeling result averaged across the 10 seeds**

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Scenarios examine different decarbonization policy pathways, varying levels and pace of renewables development, and lower levels of demand

Two "Base Case" scenarios based on AESO's preliminary 2024 LTO; these scenarios represent two different decarbonization policy pathways to net zero	
2035 Base Case	*2050 Base Case*

A set of additional scenarios to consider the implications of increasing renewables on the feasibility of new entry and economics of existing resources and retirements	
1. 2035 Additional Renewable Entry in Long Term	*1. 2050 Additional Renewable Entry in Long Term*
2. 2035 Accelerated Renewable Entry in Short Term	*2. 2050 Accelerated Renewable Entry in Short Term*
3. 2035 More Renewables Case (combo of 1 and 2)	*3. 2050 More Renewables Case (combo of 1 and 2)*
4. 2035 More Renewables Case Calibrated	*4. 2050 More Renewables Case Calibrated*

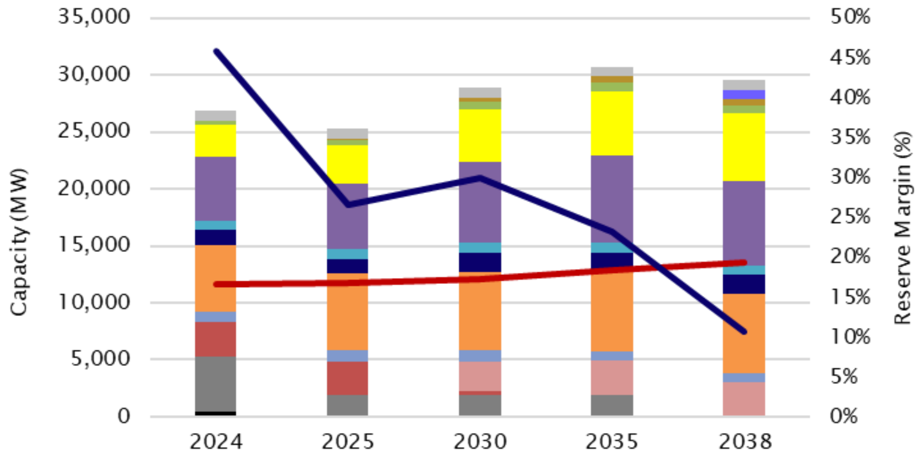
The More Renewables Cases introduce 4,520 MW of additional renewables (relative to the Base Cases) over the forecast period

LEI also tested "demand shocks"* that reduce load by 3.5% and 7.2% (or about 390 MW and 800 MW in each hour), respectively, for select years (2035 and 2038)	
2035 ~390 MW Lower Demand Case	*2050 ~390 MW Lower Demand Case*
2035 ~800 MW Lower Demand Case	*2050 ~800 MW Lower Demand Case*

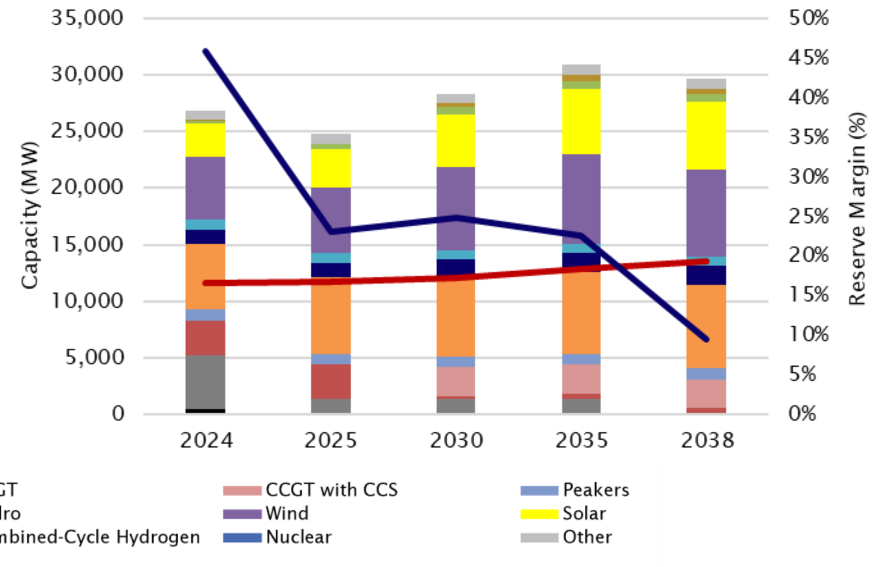
* Demand shocks are unexpected changes in demand, the underlying causes of which could reflect a variety of circumstances at a global and/or local level.

LEI's Base Cases leverage AESO's preliminary 2024 LTO modeling work, including AESO's load forecast and supply assumptions (retirements, entry)

LEI 2035 Base Case

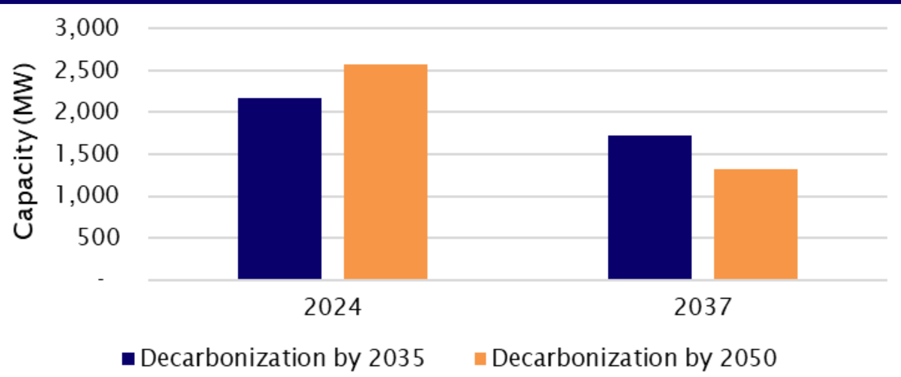


LEI 2050 Base Case



Note: Reserve margin is defined as dispatchable resources availability adjusted capacity divided by net peak demand. "Other" refers to biomass and demand response.

Coal-to-gas retirement schedules



- **Retirement schedules for coal-to-gas units differ between the AESO's 2035 and 2050 scenarios**
  - This leads to different MWs of dispatchable capacity vs renewable capacity
  - The 2050 Base Case has less dispatchable MWs than the 2035 Base Case, and as such has a tighter reserve margin between 2025 and 2038
  - The average reserve margin between 2025 and 2035 under the 2050 Base Case is 23%, compared to 27% under the 2035 Base Case

LEI tested several variations to develop the More Renewables Cases: additional renewables of about 2,100 MW in the near term, as well as additional renewables of 2,400 MW in the longer term

Renewables cases tested:

Additional Renewable Entry in Long Term (Back-End)

- Addition of 200 MW of wind and 200 MW of solar in each year after the final new addition in the 2035 Base Case and 2050 Base Case
- 200 MW is consistent with AESO generic additions in previous years

Accelerated Renewable Entry in Short Term (Front-End)

- Accelerated wind and solar additions in the near term
- Additions determined by the shortfall of capacity (in MW) between AESO's November 2023 Long-term Adequacy ("LTA") Report and preliminary 2024 LTO

More Renewables Cases under the two different carbon policy pathways

- Incorporates the back-end and front-end additions to both the 2035 and 2050 Base Cases, resulting in a 2035 More Renewables Case and a 2050 More Renewables Case

The More Renewables Cases allow LEI to test the impact of more renewables on the grid in terms of supply mix, system reliability (supply adequacy), and affordability

Yearly Additions (MW)

Wind	2025	…	2034	2035	2036	2037	2038	2039	2040
Back-End Additions	-	…	200	200	200	200	200	200	200
Front-End Additions	350	…	-	-	-	-	-	-	-
More Renewables Case	**350**	**…**	**200**	**200**	**200**	**200**	**200**	**200**	**200**

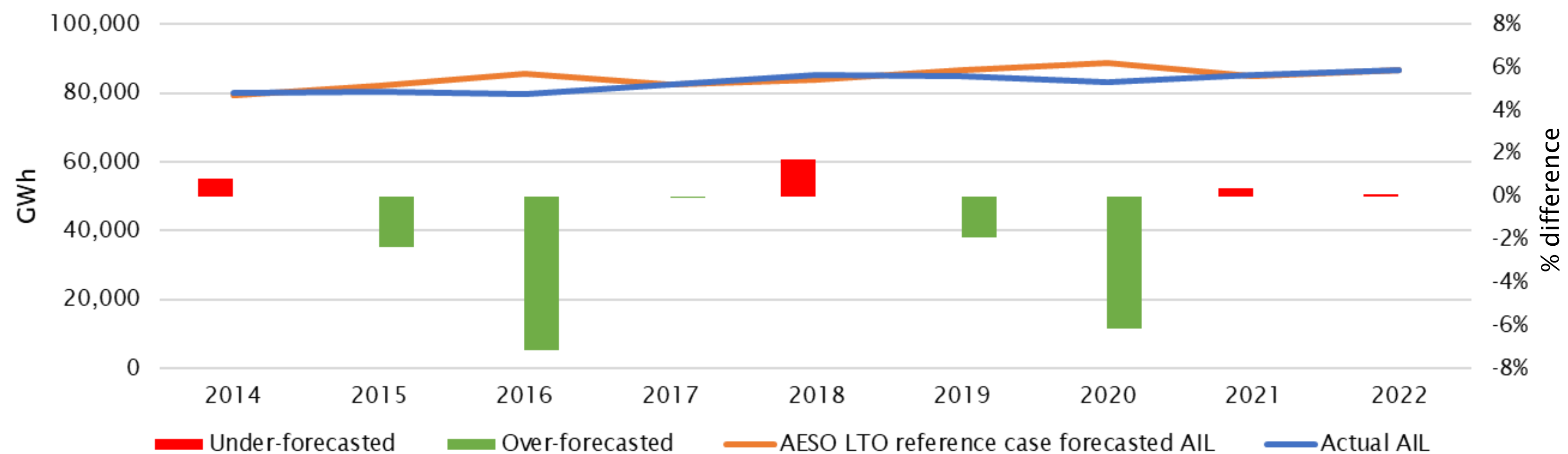
Solar	2025	…	2034	2035	2036	2037	2038	2039	2040
Back-End Additions	-	…	-	-	200	200	200	200	200
Front-End Additions	1,770	…	-	-	-	-	-	-	-
More Renewables Case	**1,770**	**…**	**-**	**-**	**200**	**200**	**200**	**200**	**200**

Note: Omitted years indicate no generic additions. Front-end additions reflect additional capacity incremental to the AESO's generic additions.

LEI's Low Demand Cases have been developed based on the observed differences between forecasted and actual AIL demand

- **The purpose of the Lower Demand Cases is to understand the impact of a demand shock on Pool Prices and reliability**
  - Demand shocks are demand changes that are unanticipated; therefore, the system is not developed in anticipation of this level of demand
- **Over the 2014-2022 timeframe, AESO's LTO forecasts have been greater than actual realized demand in four instances (green bars in the chart below)**
  - The average difference between forecasted and actual AIL demand was 3.5% (green bars in the chart below), while the maximum difference was 7.2% (for 2016, with the forecast completed in the 2014 LTO)
- **LEI developed the Lower Demand Cases by reducing the Base Case demand by 3.5% and 7.2% (or ~390 MW and ~800 MW per hour), reflecting the average and largest historical differences between forecasted and actual AIL demand**

Historical AESO LTO forecasted AIL demand vs actual AIL demand (GWh) and % difference



Sources: AESO 2014, 2017, 2019, and 2021 LTO.

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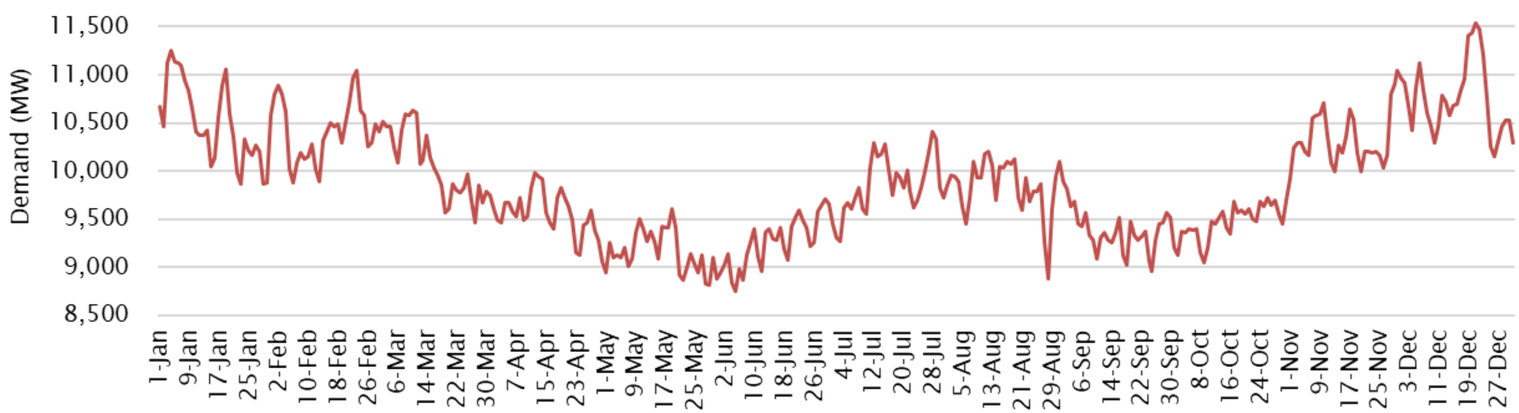
Demand-related inputs are taken primarily from AESO preliminary 2024 LTO data, as well as historical actuals

- **Demand in Alberta follows a diurnal trend and is largely driven by seasonal patterns, typically reaching its highest peak in the winter**
- **Peak demand and total energy consumption are based on AESO's AIL forecast from its preliminary 2024 LTO analysis, applied to a weather normal hourly profile (based on 2021 actuals), adjusted for behind-the-fence load with on-site generation**
  - LEI also used AESO load modifiers for DER, hydrogen, heating, projects, and energy efficiency
  - Incorporating Market Surveillance Administrator ("MSA") data from 2018-2022, where 9.5% of load is served by non-energy merit order resources, LEI estimated that on average 923 MW of AIL load is served by non-energy merit order resources
- **LEI used actual weather data in its assessment, 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 results towards low likelihood events
- **Hourly demand projections are the same across the 2035 and 2050 Base Cases and the More Renewables Cases for the weather normal model runs**

Historical daily average demand profile, 2021 (MW)



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Key assumptions and inputs used for the forward modeling exercise align with AESO's preliminary 2024 LTO projections and historical observed trends

Solar and wind generation profiles

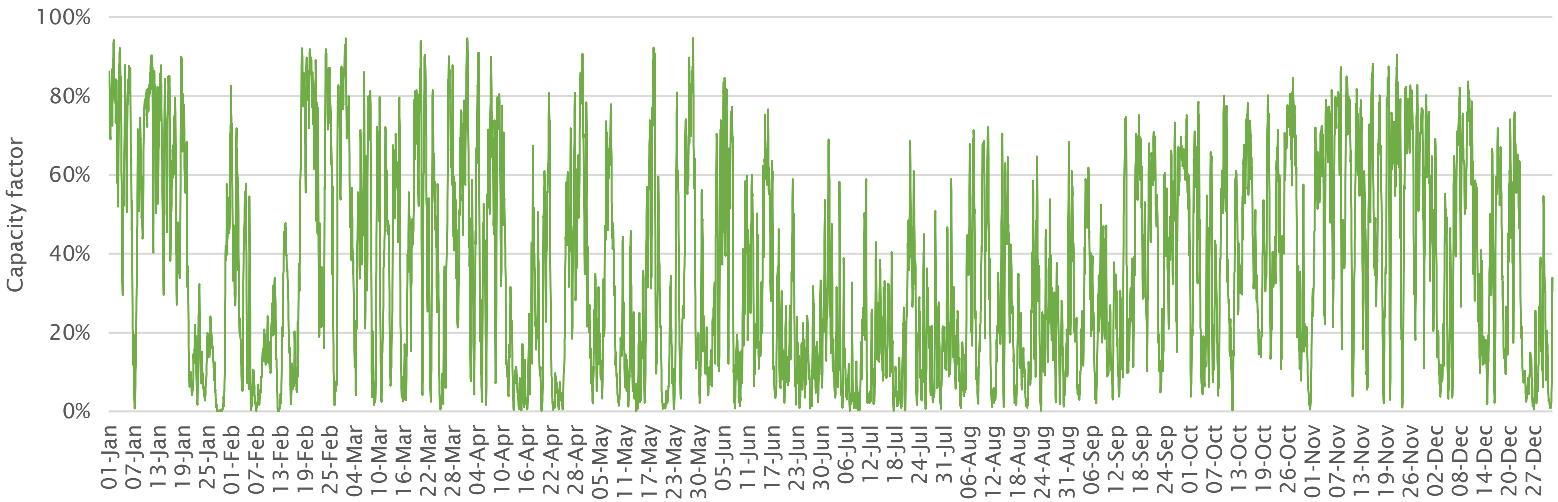
- **Hourly solar and wind generation profiles based on 2021 actuals**
  - After analyzing hourly wind and solar patterns between 2018 to 2022, LEI found that 2021 was the year where capacity factors of wind and solar were closest to longer term averages
  - LEI assumes zero-priced offers for wind and solar, consistent with observed market dynamics
  - New wind and solar assets are assumed to have higher capacity factors, based on expected wind/solar capacity factors for units located in Class 7 (wind) and Class 10 (solar) from the National Renewable Energy Laboratory ("NREL")'s 2022 Annual Technology Baseline ("ATB") forecast

Hydro generation profile

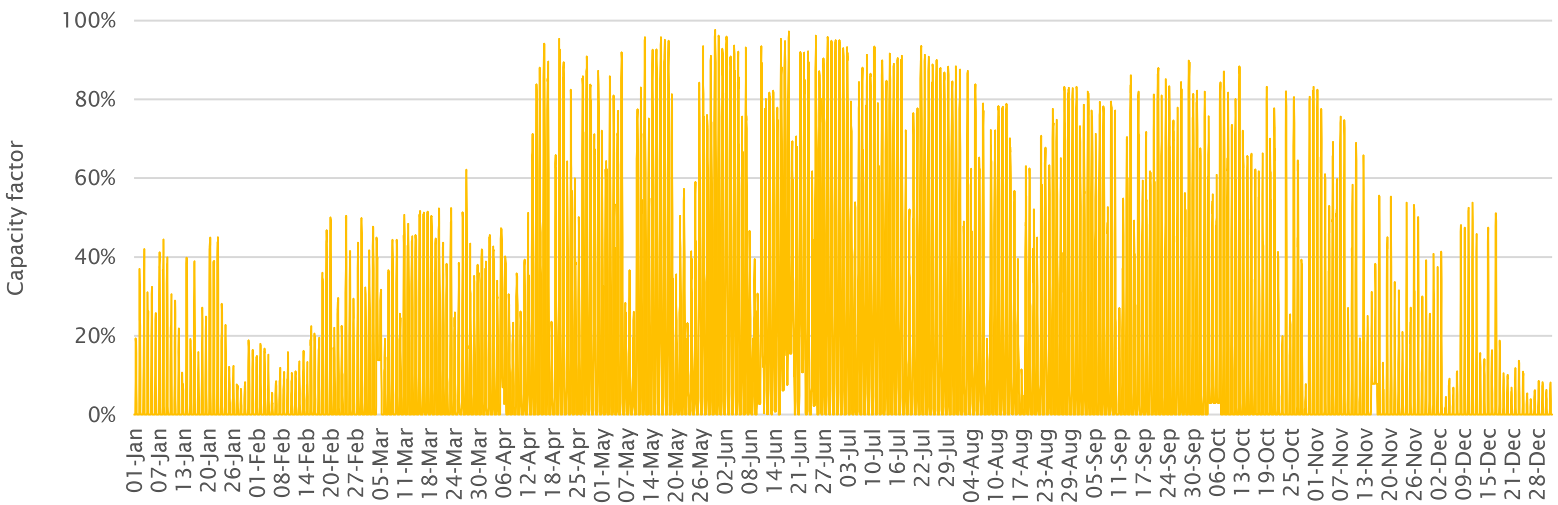
- **Hydro generation is based on the average historical hourly generation pattern of hydroelectric units from 2015 to 2023**
- **Hydro capacity is separated into run-of-river and peaking hydro units based on their historical generation pattern**
  - Run-of-river hydro units offer at $0/MWh
  - Peaking hydro units have a daily energy budget, where they allocate energy to the highest-priced hours for dispatch
  - Peaking hydro units offer at a "shadow price" based on the expected offer of the marginal unit that would otherwise clear the market; this is intended to reflect the economic opportunity costs for the peaking assets that are energy-limited

Actual 2021 historical wind and solar capacity factors are used to reflect realistic wind and solar output patterns

Historical hourly wind capacity factor, 2021 (%)



Historical hourly solar capacity factor, 2021 (%)



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Generators are not always available to be dispatched due to scheduled (maintenance) and unplanned (forced) outages – this uncertainty is reflected in LEI's simulations

- **Given Alberta's relatively small market size, the timing of outages can have a significant impact on Pool Prices – therefore LEI ran 10 iterations ("seeds") for each scenario, resulting in different outage patterns within the year (but the same overall level of outages)**
  - Economic withholding strategies also vary with each seed (although the starting strategy is the same each day, the model allows for an iterative analysis of alternative strategies as it seeks the most profitable outcomes and therefore can converge around a different solution – there are multiple possible local equilibria)
- **Outages for non-renewable generation are captured by incorporating technology-specific data on scheduled and unplanned outage levels that the North American Electric Reliability Corporation ("NERC") collects from power plant owners across all power systems under its jurisdiction in North America and summarizes in an annual publication – the Generating Availability Data System ("GADS")**
  - LEI relied on the latest NERC GADS "Generating Unit Statistical Brochure 4 - 2018-2022 - All Units Reporting" report to populate the generation schedules for non-renewable resources

Maintenance schedule

- Each unit has a required number of weeks of maintenance each year
- There are many combinations of maintenance schedules possible in an electric system with many plants
- For each new "seed", POOLMod resets the maintenance schedule

Forced outages

- Each unit has its own forced outage rate
- The forced outage rate determines the probability that a unit is on outage in each day
- POOLMod uses a random process to determine whether a unit is on outage on a daily basis

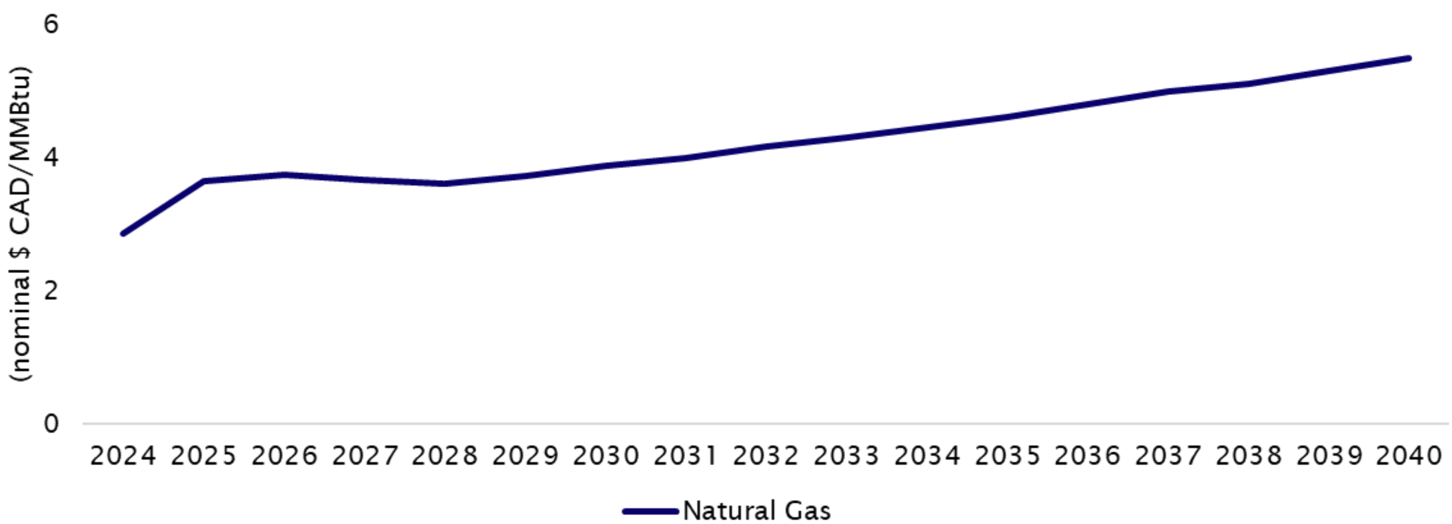
Technology	Average EFORd (%)	Average SOF (%)
Combined cycle	4	10
Coal	11	14
Internal combustion engine	12	7
Multi-turbine	14	16
Steam turbine	11	14
Gas turbine	12	7

- Equivalent Forced Outage Rate on demand ("EFORd"): measures the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate
- Scheduled Outage Factor ("SOF"): a measure of the unit's unavailability due to planned or maintenance outages

LEI developed and applied its own proprietary gas price forecast for AECO Hub in this modeling exercise

- **In the near term (2024-2028), LEI uses AECO Hub traded forwards sampled in Q3 2023 for its forecast of gas prices**
  - Near-term forwards range from $2.87/MMBtu in 2024 to $3.74/MMBtu in 2026
  - This is a decline from the very high prices in 2022, which reflected the uncertainty over gas supplies in Europe owing to embargos on Russian pipeline gas
- **In the long term (2029-2040), LEI relies on the Canadian Energy Regulator ("CER")'s 2021 long term outlook**
  - LEI has been using CER's 2021 outlook since December 2021 and believes that the CER's "Current Policies" case is still a reasonable baseline AECO outlook
- **LEI then estimated monthly prices for each year consistent with historical patterns**

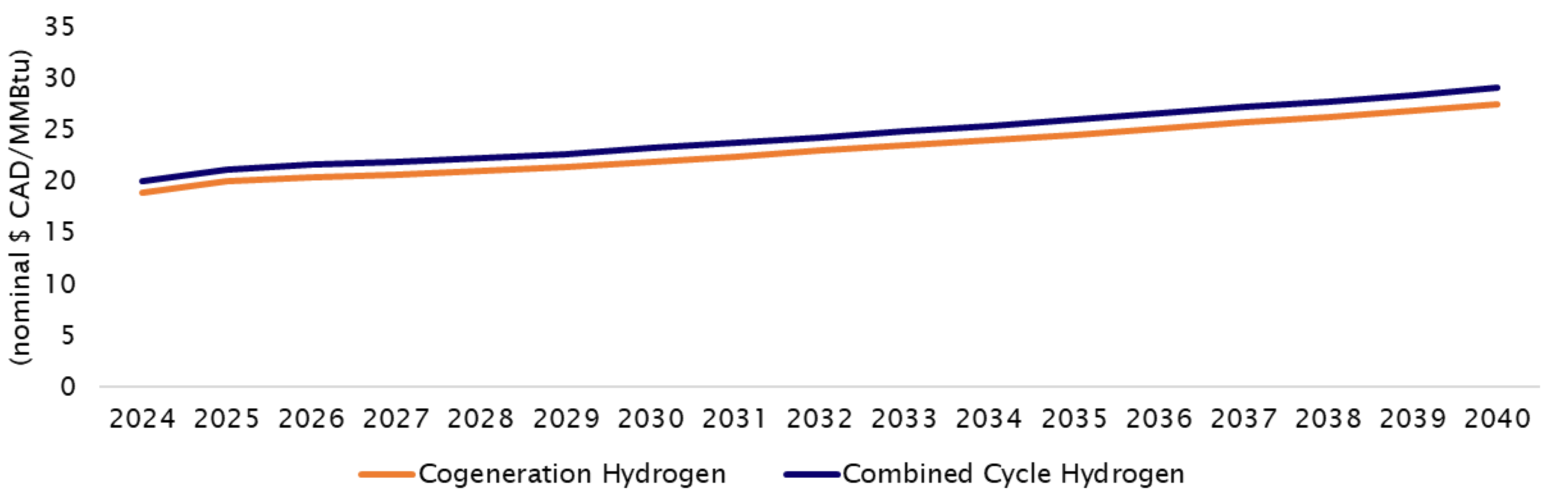
LEI gas price forecast (2024-2040)



LEI developed two hydrogen fuel price forecasts to account for the different characteristics of hydrogen technologies reflected in AESO's supply forecast

- **Different production processes for blue hydrogen have cost implications on the overall hydrogen price**
  - Cogeneration hydrogen is assumed to be produced via autothermal reforming ("ATR") on-site – i.e., ATR is co-located with electricity production
  - For combined cycle hydrogen, it is assumed that blue hydrogen would be purchased from a centrally produced area rather than be produced on-site
  - Therefore, LEI assumes transportation costs for the combined cycle hydrogen unit and no transportation costs for the co-located cogeneration unit
- **All operational characteristics, including fixed and variable costs of hydrogen production, are based on publicly available NREL models for hydrogen technologies**
- **LEI adapted these models to more accurately reflect the local context by using Alberta natural gas as the feedstock**
  - Consequently, hydrogen gas prices will vary and track Alberta's natural gas prices

LEI hydrogen price forecast (2024-2040)



LEI's carbon policy assumptions rely on various public sources, including AESO's preliminary 2024 LTO projections and current federal/provincial regulations

- **Consistent with the federal carbon pricing system, the carbon tax starts at $85/tonne of CO2e in 2024, increasing by $15/tonne increments each year and leveling off at $170/tonne in 2030; carbon tax assumptions are held constant across all modeled scenarios**
  - After 2030, LEI applies a more modest inflationary annual increase of 2% to the price of carbon, consistent with AESO's assumptions in the preliminary 2024 LTO

- **Technology Innovation and Emissions Reduction ("TIER") emissions performance standards across the 2035 and 2050 decarbonization scenarios are different**
  - Under the 2035 decarbonization scenario, the emissions performance standard is set to decline from 0.3552 tonnes/MWh in 2024 to 0 tonnes/MWh by 2035
  - In contrast, the 2050 decarbonization scenario sees the emissions performance standard decline from 0.3552 tonnes/MWh in 2024 to 0 tonnes/MWh by 2050

High Performance Benchmark Assumptions	Unit	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Decarbonization by 2050	t/MWh	0.36	0.35	0.34	0.33	0.33	0.32	0.31	0.30	0.28	0.26
Decarbonization by 2035	t/MWh	0.36	0.35	0.34	0.33	0.33	0.32	0.31	0.25	0.19	0.12
High Performance Benchmark Assumptions	**Unit**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Decarbonization by 2050	t/MWh	0.25	0.23	0.22	0.20	0.19	0.17	0.16	0.14	0.12	0.11
Decarbonization by 2035	t/MWh	0.06	-	-	-	-	-	-	-	-	-

LEI's approach to the draft federal Clean Electricity Regulations ("CER")

- According to the draft CER, the proposed regulations apply to all electricity generation units that meet the applicability criteria:
  a. has an electricity generation capacity of 25 MW or more;
  b. generates electricity using fossil fuel; and
  c. is connected to an electricity system that is subject to NERC standards
- 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
- New units that come into operation after January 1, 2025 will be required to meet the performance standard by January 1, 2035
- By 2035, unabated gas-fired units that have a generation capacity of 25 MW or more will be limited to operating 450 hours/year, ~5% of the plant's operating capacity
- Units below 25 MW are exempt from the draft CER

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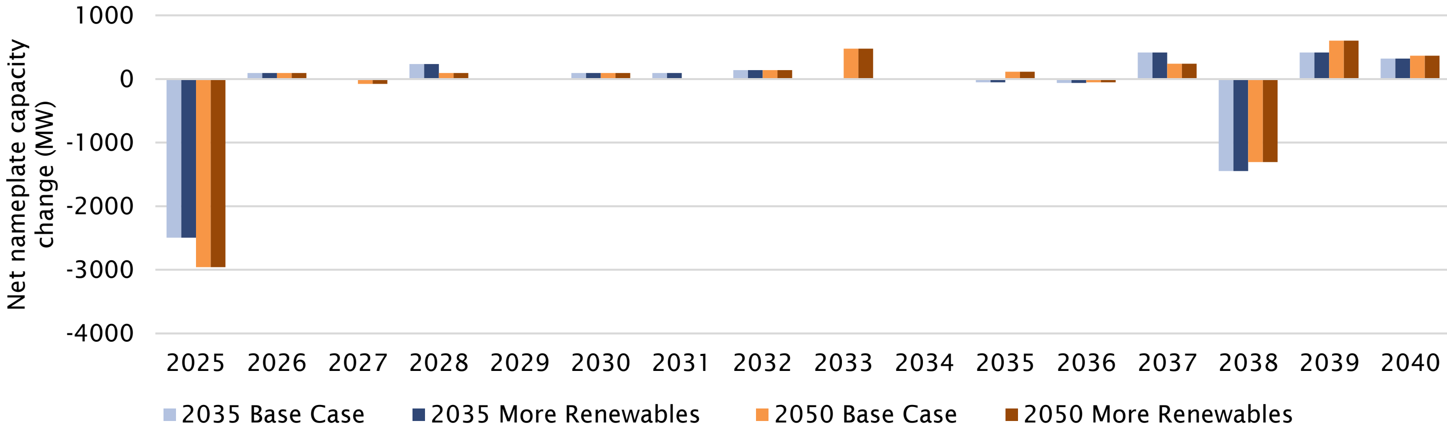
Additional technical assumptions and operating parameters are based on publicly available data and industry-standard assumptions

- **Other technical assumptions (heat rates, minimum stable generation ("MSG") levels, minimum on and off times, etc.) were developed by LEI for purposes of its multi-client forward price outlook, leveraging well-accepted industry data**
  - Heat rate curves estimated from historic hourly generation and offer data published by AESO and cross-referenced with data from similar technology/vintage plants in the US (sourced from EIA, EPA, FERC)
  - MSG levels implied from historical hourly generation data and offer data published by AESO
  - Minimum on/off hours based on energy merit order offer patterns/generation data patterns
- **Some price responsive load ("PRL") is included in the modeling**
  - Based on data published by the MSA, approximately 300-500 MW of load foregoes consumption of electricity when Pool Prices increase
  - These levels of PRL are also consistent with information released over the years by the major industrial trade associations in Alberta regarding their members' direct participation in the energy market
- **Imports are represented as virtual supply (with import volumes based on pricing outcomes); exports are represented as virtual demand (based on historical patterns and also related to pricing outcomes)**
  - Levels of imports and exports are determined hourly based on Pool Price – higher priced hours are observed to have more imports and lower priced hours have more exports
  - Maximum import available transfer capability ("ATC") over the forecast period is expected to increase by 388 MW by 2030 following intertie restorations
  - Exports were developed by analyzing the historical export quantity correlation with the Mid-C implied market heat rate, the modeled export quantity is based on the forecasted Mid-C gas price

Thermal net new entry across both 2035 and 2050 scenarios is limited due to a significant level of retirements

Net annual non-renewable entry, 2035 and 2050 scenarios



Note: Non-renewable entry in this case is inclusive of retrofitted CCGT with CCS units and hydrogen units.

- **Thermal installed capacity in the 2050 scenarios is lower than the 2035 scenarios from 2025 to 2038**
  - The 2050 case sees the retirement of 2,566 MW of coal-to-gas units in 2024; 395 MW more than the 2035 scenarios
- **Net additions in the late 2020s and early 2030s are driven by cogen and cogen hydrogen new entries**
- **Post-2037, the 2035 scenarios see more capacity additions of combined cycle hydrogen units, approximately 1,255 MW more capacity than the 2050 scenarios by 2040**
- **The limited combined cycle hydrogen capacity is offset by new CCGT and simple cycle additions in the 2050 scenarios**
- **Projected new resource additions are subject to significant technological risks**
  - LEI relies on AESO's preliminary 2024 LTO supply mix assumptions, which incorporate new generation technologies (e.g., hydrogen-based generation, natural gas-fired generators retrofitted with carbon capture technologies, and SMRs)
  - LEI took these assumptions as given and did not consider the investment risk hurdles involved in the development of these technologies (i.e., cost overruns, delays, and other construction, financing, and operating risks)

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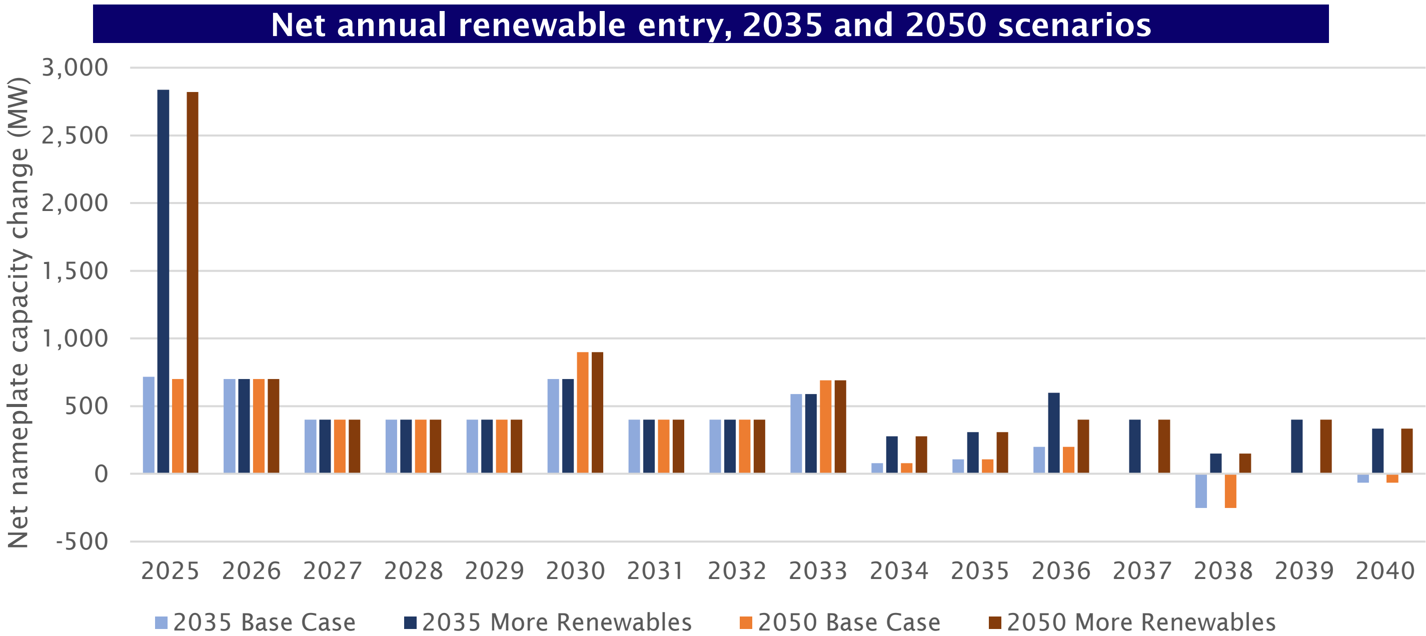
Solar and wind new entry are similar across the 2035 and 2050 Base Cases over the longer term



- **Wind capacity is 300 MW higher in the 2050 scenarios due to an additional 200 MW of new entry in 2030, and an additional 100 MW of new entry in 2033 (consistent with AESO's LTO)**
  - In 2038 and 2040, AESO projects net retirement of wind and solar capacity, leading to negative MW change
- **Renewables in the near-term are based on AESO's November 2023 LTA Report**
  - New additions factor in projects in the interconnection queue that have received regulatory approval from the AUC
  - The shortfall in capacity is then added on top of AESO's generic additions
- **Under the More Renewables Cases, additions in the long-term of 200 MW are consistent with the AESO's approach for long-term additions**

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3 **Key modeling results**

Implications of different decarbonization policies

Implications of additional renewables

Implications of lower demand

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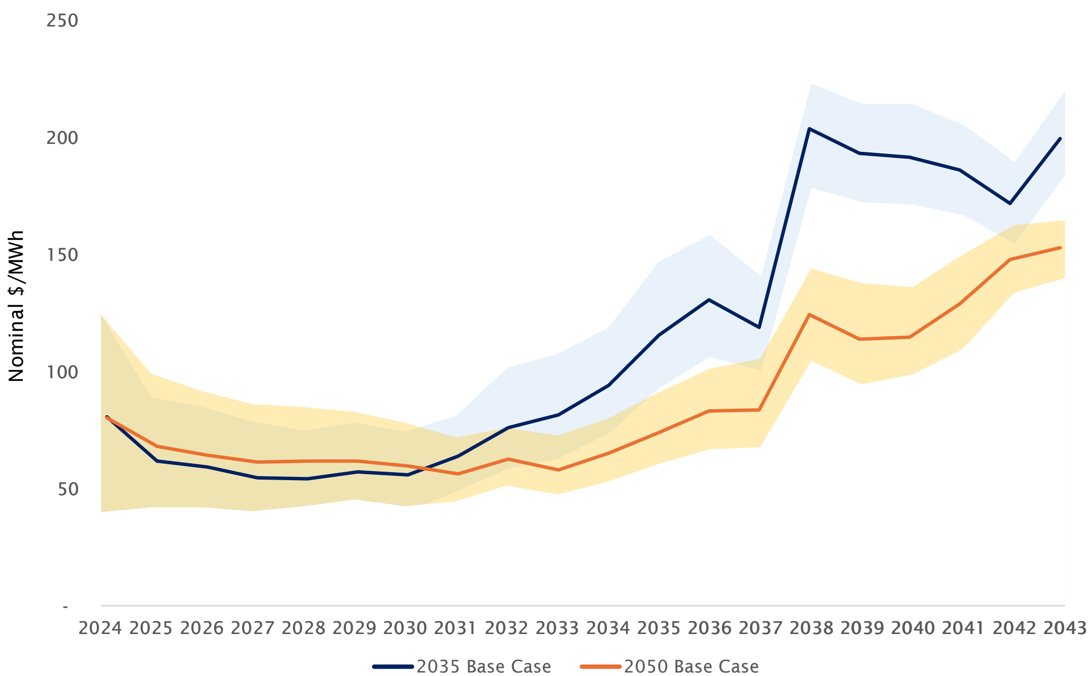
Pool Prices under the 2050 Base Case are lower than under the 2035 Base Case from 2031 onwards, largely due to the impact of less stringent carbon emissions performance standards

- **Under LEI's 2035 Base Case, average Pool Prices grow from an average of $81/MWh in 2024 to $200/MWh by 2043 under 'weather normal' conditions**
  - Pool Prices rise after 2030 due to tight supply-demand conditions, higher carbon costs, and hydrogen prices
- **LEI's 2050 Base Case demonstrates a more modest increase in Pool Prices: from an average of $80/MWh in 2024 to $153/MWh by 2043 under 'weather normal' conditions**
  - Considering less stringent conditions to achieve net zero under the 2050 scenario, the replacement of existing technologies with cleaner but more expensive technologies (like hydrogen) occurs gradually; thus, price increases are gradual

Annual average Pool Price forecast for LEI's Base Cases (weather normal)

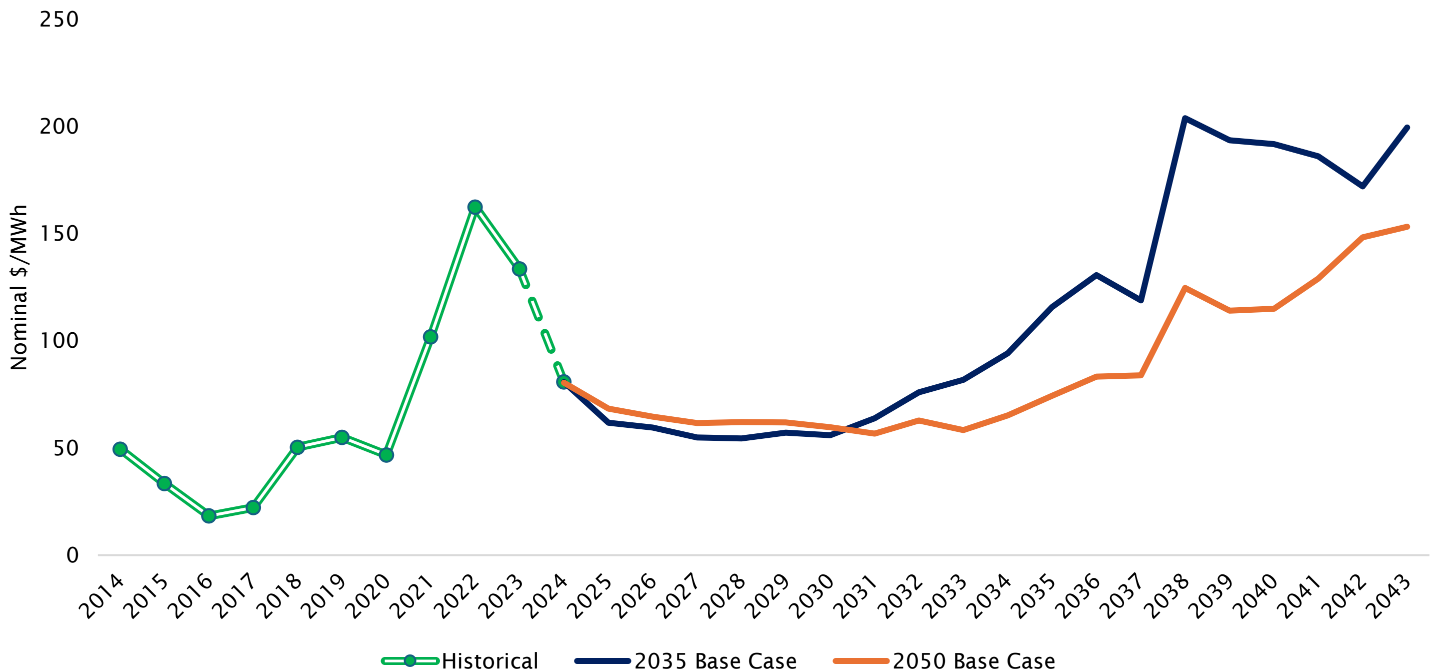


For the 20-year forecasts, LEI ran its simulation model 10 times (seeds), with randomized forced outages and maintenance schedules, which resulted in a range of Pool Price outcomes. The shaded areas represent the range of annual average Pool Price outcomes modeled by LEI, and the solid lines represent the average of the 10-seed results under each Base Case.

Pool Prices are expected to reach their highest forecasted levels in 2038 under the 2035 Base Case, higher than Pool Prices reached in 2022

- **In the near- to mid-term, forecasted Pool Prices under both Base Cases are lower than historical average Pool Prices recorded in 2021-2023**
  - Significant generation investment is expected to increase supply and put downward pressure on Pool Prices in the near-term
  - In addition, significant wind and solar new entry results in more $0/MWh priced hours, which drives Pool Prices down

Annual average Pool Price forecast for LEI's Base Cases (weather normal) compared to historical Pool Prices



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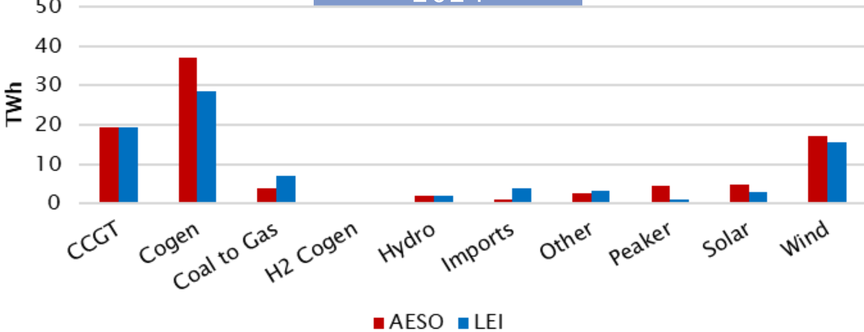
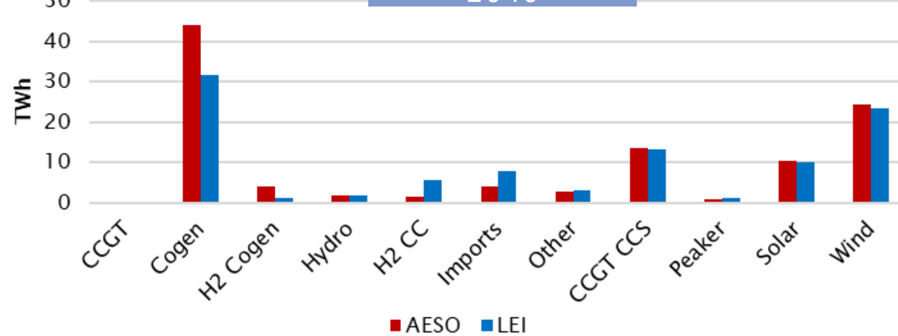
In 2024, CCGT and cogen account for the largest share of generation; by 2040, renewable generation accounts for nearly 50% of total generation

Annual generation by fuel type (TWh) – 2035 Base Case

2024

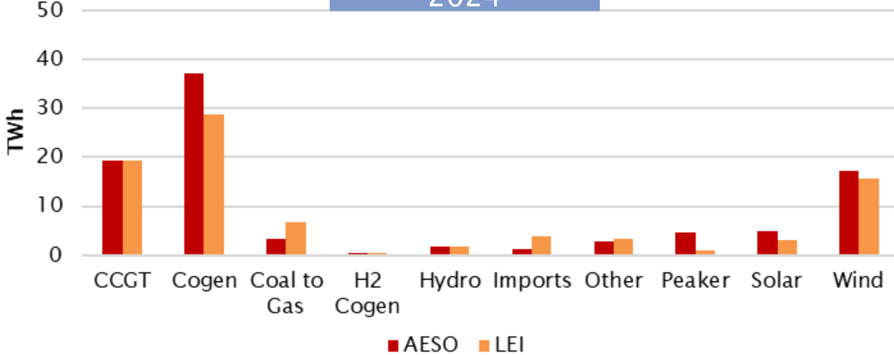


2040

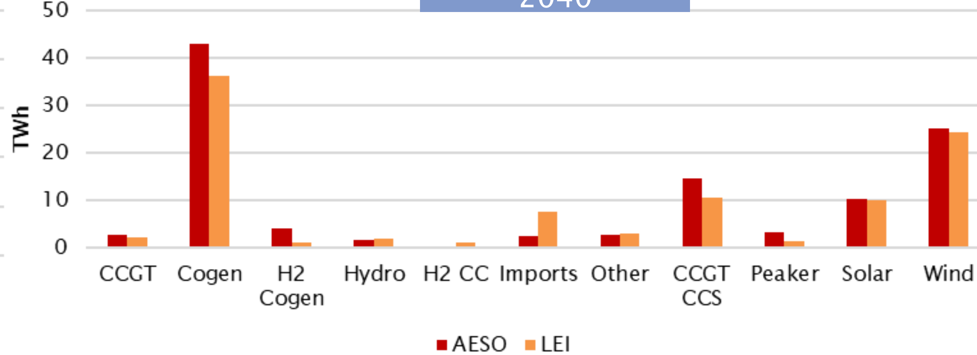


Annual generation by fuel type (TWh) – 2050 Base Case

2024



2040



- **Less stringent emissions performance standards allow for slightly higher unabated gas unit operations in the 2050 Base Case**
  - Under the 2035 Base Case, by 2040, there is no CCGT without CCS, while the 2050 Base Case has a few units still generating
  - Similarly, for peakers, annual generation under the 2050 Base Case is slightly higher than the 2035 Base Case
- **LEI's and AESO's projected energy mix is generally aligned**
  - In 2024, LEI modeled more output from coal-to-gas units and others – the generation in the "others" category includes biomass, demand response, and coal (just for 2024); in 2040, the difference in cogen output is largely offset by LEI's output from imports and CCGT with CCS

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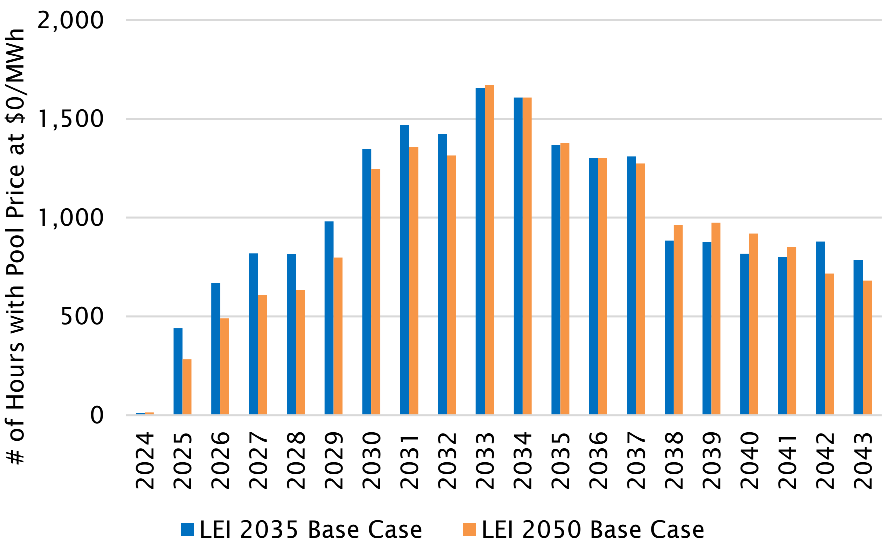
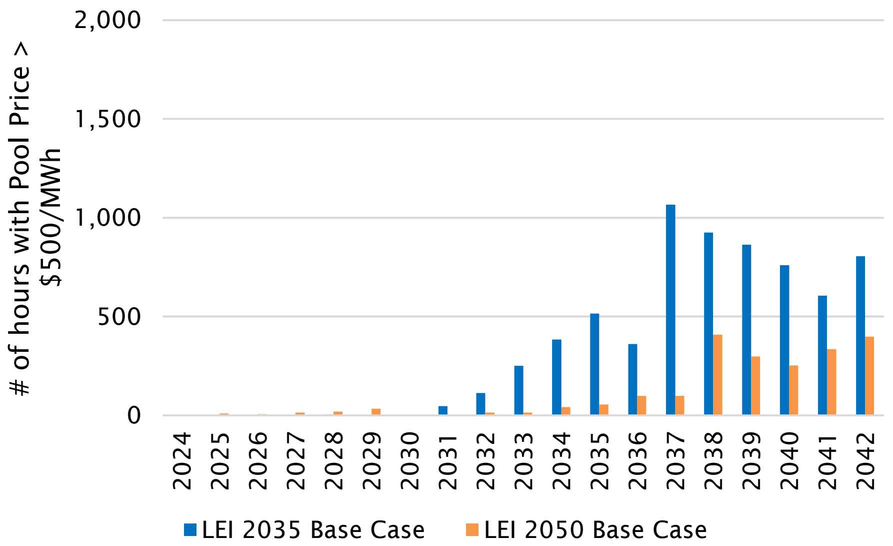
Pattern of zero priced hours is similar across the 2035 and 2050 Base Cases, but there are more instances of price spikes (>$500/MWh) in the 2035 Base Case

Frequency of zero prices



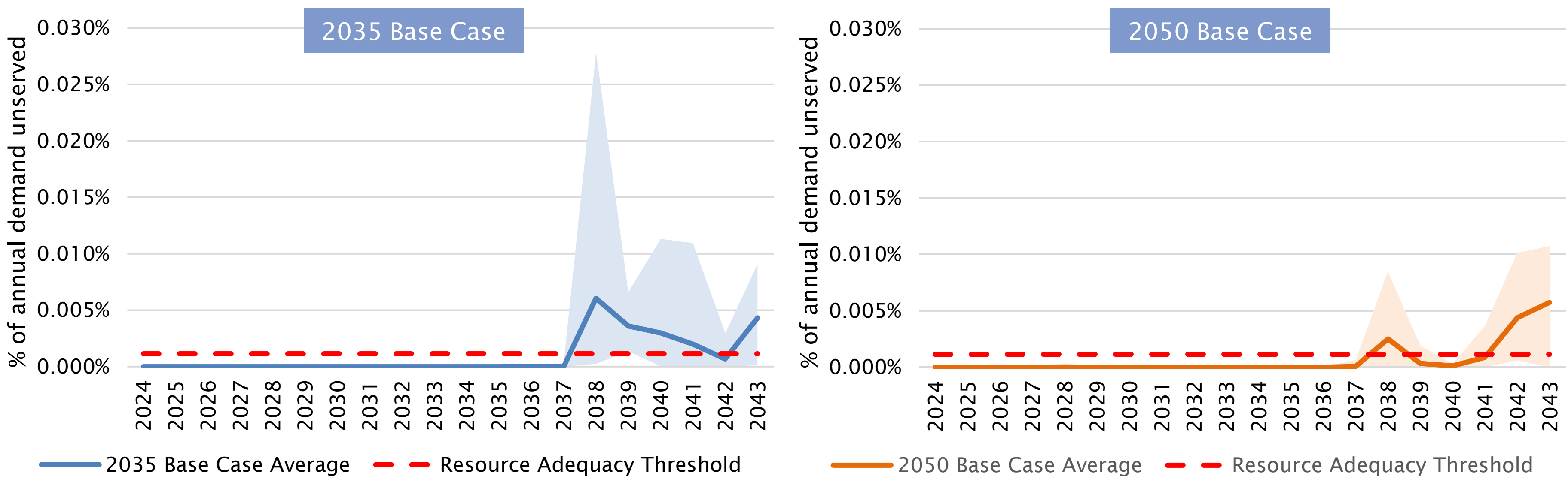
Frequency of Pool Prices > $500/MWh



- **Frequency of zero prices is higher in the 2035 Base Case in the early years (before 2038) because the 2035 Base Case has more coal-to-gas units, which have high minimum stable generation that offers at $0/MWh**
  - This trend reverses after 2038, when all coal-to-gas units retire in both cases. After 2038, the 2050 Base Case has slightly more wind, which results in more $0/MWh hours than the 2035 Base Case
- **Frequency of Pool Prices greater than $500/MWh is significantly higher in the 2035 Base Case than the 2050 Base Case**
  - Price spikes occur due to a combination of factors, including higher short-run marginal costs from hydrogen and CCGT with CCS in the 2035 Base Case, and more economic withholding in years where the 2035 Base Case has more coal-to-gas units online than the 2050 Base Case

Alberta's electricity system becomes significantly less reliable after 2037 – even without factoring in weather impacts – due to the retirement of all remaining coal-to-gas units (in both the 2035 and 2050 Base Cases)

% of annual demand unserved (10-seed average, weather normal conditions)



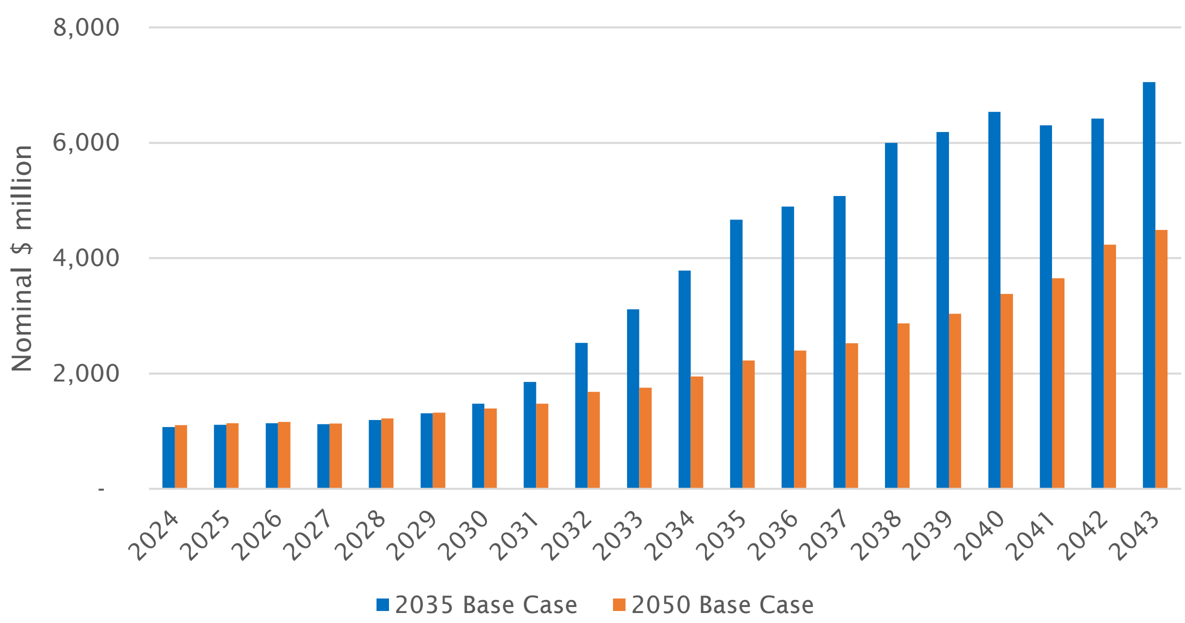
- **Shaded regions indicate the range of demand unserved (as % of annual demand) across the different seeds (reflecting varying generation outage patterns), while the solid lines reflect the average demand unserved (as % of annual demand)**
- **By the late 2030s, reliability risk under the 2035 Base Case is expected to be worse than the 2050 Base Case**
- **However, 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**

Note: 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%.

Decarbonization policy choice can lead to significant differences in production costs after 2030: 2035 Base Case has significantly higher variable costs of electricity generation than the 2050 Base Case

- **From 2024 to 2043, total production cost (sum of fuel costs + variable O&M cost + carbon cost of all units) for the 2035 Base Case averages 65% higher than the 2050 Base Case**
  - The difference between the two cases is the largest in 2035, where the 2035 Base Case total production cost is 109% higher than the 2050 Base Case
- **This is largely due to differences in carbon policy – while the nominal carbon tax price is the same, the amount that a fossil-based generator needs to pay is higher in the 2035 Base Case, due to more stringent emissions performance standards**

Total production cost (2035 Base Case vs 2050 Base Case, nominal $ million)



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LEI monitored the simulated profits of resources to assess the economic viability of both new generation projects and existing assets

- **For new entry, LEI considered the investment decision and monitored the return on invested capital, as well as ongoing operations, and sufficiency of gross profits to cover minimum going forward fixed costs; LEI used AESO's cost assumptions for new plants**

All-in fixed cost for new generation (nominal $/kW-year)

Technology	2030	2035	2040
CCGT	273	-	-
CCGT with CCS with ITC	412	456	504
CCGT with CCS Retrofits with ITC	214	317	354
Peaker (Frame)	164	181	200
Cogeneration Hydrogen with ITC	134	172	190
Combined Cycle Hydrogen with ITC	-	-	334
Wind with ITC	239	321	346
Solar with ITC	156	208	221
Storage with ITC	182	258	273

- **For existing generation, LEI considered whether gross profits from the wholesale energy market are sufficient to cover minimum going forward fixed operations and maintenance**

Fixed O&M cost for existing generation (nominal $/kW-year)

Technology	2030	2035	2040
Existing CCGT	24	27	30
Coal-to-gas units	70	77	85
Existing peaker (Frame)	12	13	15
Existing cogen	12	13	15
Existing wind	45	50	55
Existing solar	26	29	32
Existing storage	70	77	85

Source: All-in fixed costs based on costs reported in AESO's preliminary 2024 LTO. Fixed O&M costs for existing generation based on generic technology-level information and intentionally does not reflect precise costs for any specific operating plant in Alberta.

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In the 2035 Base Case, new generation investment is earning low returns in the first ten years, but profitability steps up in the back years, and all new resources are generally earning enough to cover their fixed O&M costs

- **Net yield is calculated based on the gross profits earned by the resource in the energy market (revenue – SRMC), less fixed O&M costs by technology type, and compared against the net capital cost of the new entry**

Energy market profits *=*

realized energy price – (fuel price x heat rate) – variable O&M costs – carbon costs (or revenue)

Net yield *= (annual energy markets profits – fixed O&M costs) / net capital cost*

- **Assuming required return for new generation investment of 10.5% (based on AESO's nominal pre-tax WACC), most new generation capacity is under-earning in the first ten years of the forecast period, but returns improve in the later years**

Modeled pre-tax net yield of new entry (2035 Base Case)

Technology	2030	2035	2040
Gas-fired units			
Newer CCGT (online in 2024)	2%	N/A	N/A
Newer CCGT with CCS Retrofits with ITC	9%	8%	21%
Older CCGT with CCS Retrofits with ITC	4.1%	8%	20%
Peaker (Frame)	-1%	5%	15%
Hydrogen			
Cogeneration Hydrogen with ITC	-18%	-6%	14%
Combined Cycle Hydrogen with ITC	N/A	N/A	19%
Renewables and storage			
Wind with ITC	14%	5%	11%
Solar with ITC	10%	3%	4%
Storage with ITC*	-2%	0%	1%

Note: This profitability analysis only includes energy market revenues and carbon offsets. Some technologies, such as storage, are expected to earn a large proportion of their revenues from ancillary services markets, which are not included in this financial analysis.

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Under the 2050 Base Case, gas-fired and hydrogen-based new resources face somewhat poorer economics as compared to the 2035 Base Case, due to lower Pool Prices

- **Under the 2050 Base Case, Pool Prices are lower (relative to the 2035 Base Case) for two main reasons:**
  - Less stringent carbon emissions performance, which lowers the marginal cost of gas-fired units
  - Reduced price impact from economic withholding (before all coal-to-gas retires)
- **This results in overall lower profits for new investment through 2040; gas-fired new entry and retrofitted units are projected to earn their target return (or higher) after 2040**
  - Some new investments – like hydrogen-based units – are not projected to achieve 10.5% returns within the 20-year modeled timeframe; however, under a different fuel forecast and with different operating conditions (and capital cost estimates), the financial outcomes may improve

Modeled pre-tax net yield of new entry (2050 Base Case)

Technology	2030	2035	2040
Gas-fired units			
Newer CCGT (online in 2024)	N/A	5%	9%
Newer CCGT with CCS Retrofits with ITC	10%	5%	9%
Older CCGT with CCS Retrofits with ITC	6.1%	2.8%	8%
Peaker (Frame)	0%	1%	5%
Hydrogen			
Cogeneration Hydrogen with ITC	-17%	-15%	-8%
Combined Cycle Hydrogen with ITC	N/A	N/A	2%
Renewables and storage			
Wind with ITC	15%	9%	11%
Solar with ITC	11%	7%	6%
Storage with ITC*	-2%	-1%	-1%

Note: This profitability analysis only includes energy market revenues and carbon offsets. Some technologies, such as storage, are expected to earn a large proportion of their revenues from ancillary services markets, which are not included in this financial analysis.

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Agenda

3 **Key modeling results**

- Implications of different decarbonization policies
- **Implications of additional renewables**
- Implications of lower demand

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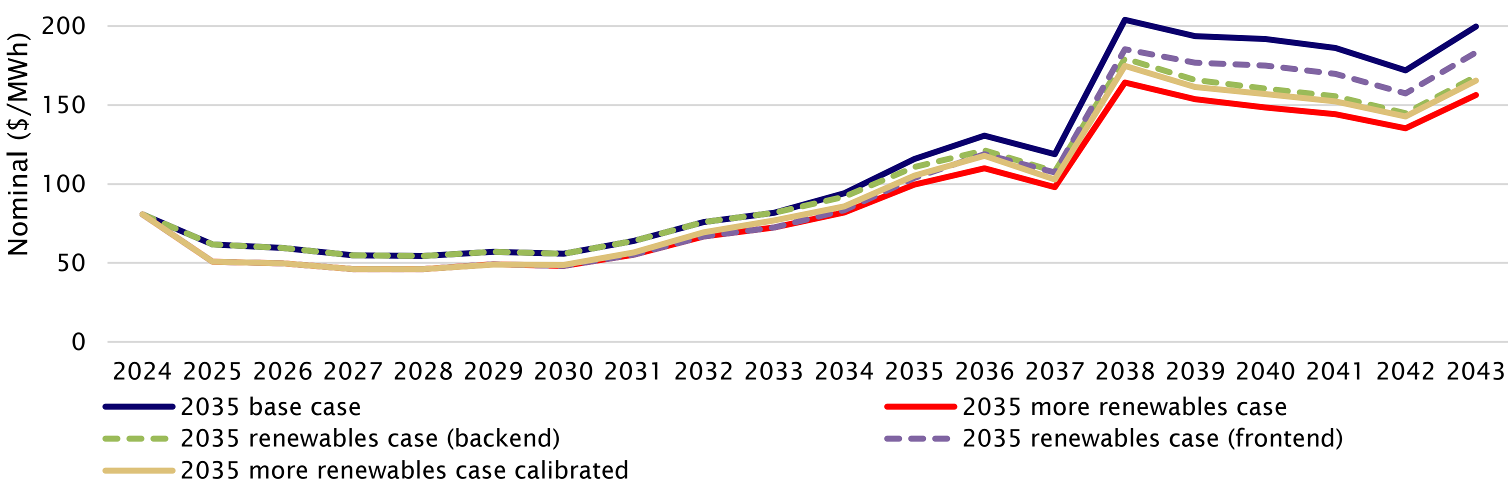
Additional renewable generation puts downward pressure on annual average Pool Prices in the longer term, requiring further evaluation of the impact of more renewables on other generation investment

- **Additional renewable generation reduces annual average Pool Prices, especially in the later years of the forecast**
  - By 2040, Pool Prices under the 2035 Base Case reach $192/MWh (CAGR of 4.6% from 2024); adding 4,520 MW of renewables drives down Pool Prices to $149/MWh by 2040 under the 2035 More Renewables Case (CAGR of 3.4% from 2024)
- **The reduction in Pool Prices reduces the economics of some new CCGTs and CCGT with CCS retrofits (see next few slides); LEI modified new entry/retrofits to arrive at the "Calibrated" More Renewables Case**
  - 156 MW of CCGT, instead of retrofitting with CCS, would retire in 2030 – this pushes Pool Prices back up in the 2030s, allowing other resources to return to similar levels of profitability as under the 2035 Base Case

Annual average Pool Price for the 2035 Base Case and 2035 More Renewables Cases (nominal $/MWh)



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Modeling results of the 2035 More Renewables Case indicate that retrofitting CCGTs with CCS may not be economically viable for some older CCGTs; older CCGTs may choose to retire early instead of retrofitting

- **Additional renewables result in lower Pool Prices, including more frequent zero Pool Prices, which leads to lower profitability for gas- and hydrogen-fired new entry**
- ***Without* additional renewables, older CCGTs with CCS retrofits can cover their fixed O&M costs in 7 out of 10 years in 2028-2037**
- ***With* additional renewables, older CCGTs with CCS retrofits are only marginally able to recover their fixed O&M costs in 2028-2032, and their profitability continues to be much lower (relative to the 2035 Base Case) through the late 2030s**
  - Such economic returns may suggest the possibility of a different longer term market outcome, where some of the older CCGTs may choose to retire instead of retrofitting with CCS – this forms the basis of developing the More Renewables Calibrated Case

Modeled pre-tax net yield of new entry (2035 More Renewables Case)

Technology	2030	2035	2040
Gas-fired units			
Newer CCGT (online in 2024)	1%	N/A	N/A
Newer CCGT with CCS Retrofits with ITC	8%	6%	14%
Older CCGT with CCS Retrofits with ITC	3%	6%	14%
Peaker (Frame)	-1%	4%	11%
Hydrogen			
Cogeneration Hydrogen with ITC	-19%	-9%	4%
Combined Cycle Hydrogen with ITC	N/A	N/A	11%
Renewables and storage			
Wind with ITC	13%	3%	6%
Solar with ITC	8%	1%	0%
Storage with ITC*	-2%	0%	1%

Note: This profitability analysis only includes energy market revenues and carbon offsets. Some technologies, such as storage, are expected to earn a large proportion of their revenues from ancillary services markets, which are not included in this financial analysis.

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With more renewables layered on top of the 2035 Base Case, if one existing CCGT decides to retire instead of retrofit with CCS, Pool Prices would increase, improving the profitability of other units

- **LEI tested retiring one CCGT and two CCGTs to understand how the economics of other units would be impacted, and found that retiring two CCGTs would bring the economics of other units to be over the 2035 Base Case levels**
- **The increase in Pool Price is caused by both high prices due to changes in merit order, but also worse reliability (due to the decrease in CCGT fleet size)**
- **Retiring one CCGT in 2030 would change the economics of the remaining CCGTs with CCS retrofits – they would go from having a negative net present value ("NPV") to positive NPV**
  - NPV is calculated based on the sum of discounted net profits throughout the forecast period using a 10.5% discount rate

Modeled pre-tax net yield of new entry (2035 More Renewables Calibrated Case)

Technology	2030	2035	2040
Gas-fired units			
Newer CCGT (online in 2024)	1%	N/A	N/A
Newer CCGT with CCS Retrofits with ITC	8%	7%	16%
Older CCGT with CCS Retrofits with ITC	3%	8%	16%
Peaker (Frame)	-1%	5%	13%
Hydrogen			
Cogeneration Hydrogen with ITC	-19%	-7%	8%
Combined Cycle Hydrogen with ITC	N/A	N/A	14%
Renewables and storage			
Wind with ITC	13%	3%	6%
Solar with ITC	8%	1%	0%
Storage with ITC*	-2%	0%	1%

Note: This profitability analysis only includes energy market revenues and carbon offsets. Some technologies, such as storage, are expected to earn a large proportion of their revenues from ancillary services markets, which are not included in this financial analysis.

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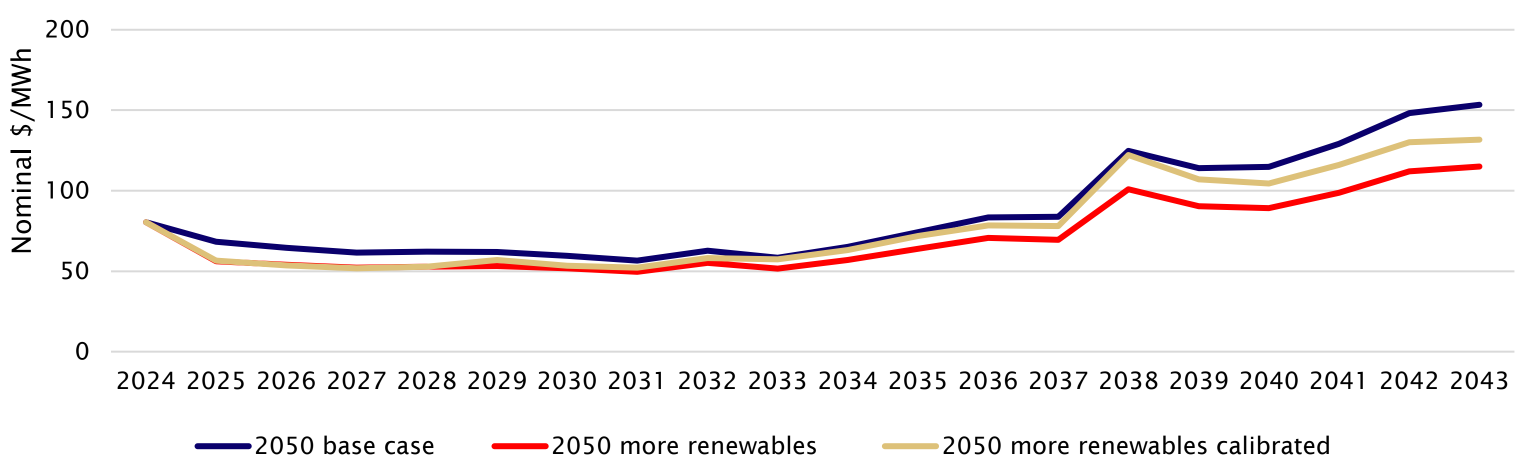
Additional renewables have a bigger price effect on annual average Pool Prices in the longer term under the 2050 Base Case

- **Under the 2050 Base Case, Pool Prices grow from an average of $80/MWh in 2024, to an average of $153/MWh by 2043 (CAGR of 3.3% from 2024)**
  - 4,520 MW of additional renewable capacity drives down Pool Prices by $38/MWh by 2043, resulting in a CAGR of only 1.8% under the 2050 More Renewables Case
- **Calibrating new entry (by cancelling 125 MW of new entry) increases Pool Prices closer to the 2050 Base Case**
  - Average Pool Prices at the end of the forecast timeframe increase from $115/MWh under the 2050 More Renewables Case to $132/MWh under the 2050 More Renewables Calibrated Case
- **The system is more sensitive to supply changes in the 2050 More Renewables Case, as the system is less reliable in the back-end (2040+) as compared to the 2035 More Renewables Case**

Annual average Pool Price for the 2050 Base Case and 2050 More Renewables Cases (nominal $/MWh)



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Testing of the 2050 More Renewables Case indicates that 125 MW of gas-fired units may not be economically sustainable, due to the resulting Pool Price impacts of additional renewable generation

- **More Renewables layered on top of the 2050 Base Case puts further pressure on the economics of gas-fired units**
  - Many new or retrofitted CCGTs are only able to cover their fixed O&M costs – even by the late 2030s
  - Older CCGTs with CCS retrofits are only marginally able to recover their fixed O&M costs over an extended timeframe (during the 2033-2037 period)
  - Hydrogen-based units are not able to earn a positive return on investment even by the end of the 20-year forecast period

Modeled pre-tax net yield of new entry (2050 More Renewables Case)

Technology	2030	2035	2040
Gas-fired units			
Newer CCGT (online in 2024)	N/A	3%	5%
Newer CCGT with CCS Retrofits with ITC	8%	3%	6%
Older CCGT with CCS Retrofits with ITC	5%	2%	5%
Peaker (Frame)	0%	1%	4%
Hydrogen			
Cogeneration Hydrogen with ITC	-18%	-16%	-13%
Combined Cycle Hydrogen with ITC	N/A	N/A	-1%
Renewables and storage			
Wind with ITC	13%	8%	7%
Solar with ITC	8%	5%	3%
Storage with ITC*	-2%	-1%	-1%

Note: This profitability analysis only includes energy market revenues and carbon offsets. Some technologies, such as storage, are expected to earn a large proportion of their revenues from ancillary services markets, which are not included in this financial analysis.

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Cancelling 125 MW of new entry in 2029-2033 brings the profitability of other units back to the 2050 Base Case levels

- **CCGTs with CCS retrofits are not able to earn a reasonable rate of return in all 2050 cases due to the low carbon price**
- **Cancelling 125 MW of new entry only helps bring the net yield of CCGT with CCS retrofits to be non-negative and similar to 2050 Base Case levels**
- **Even though the profitability of new entry improves under the 2050 More Renewables Calibrated Case, levels are still lower than those in the 2035 Base Case and 2035 More Renewables Calibrated Case**

Modeled pre-tax net yield of new entry (2050 More Renewables Calibrated Case)

Technology	2030	2035	2040
Gas-fired units			
Newer CCGT (online in 2024)	N/A	N/A	8%
Newer CCGT with CCS Retrofits with ITC	9%	5%	9%
Older CCGT with CCS Retrofits with ITC	5%	4%	8%
Peaker (Frame)	0%	2%	6%
Hydrogen			
Cogeneration Hydrogen with ITC	-18%	-14%	-7%
Combined Cycle Hydrogen with ITC	N/A	N/A	3%
Renewables and storage			
Wind with ITC	14%	8%	8%
Solar with ITC	9%	5%	3%
Storage with ITC*	-2%	-1%	0%

Note: This profitability analysis only includes energy market revenues and carbon offsets. Some technologies, such as storage, are expected to earn a large proportion of their revenues from ancillary services markets, which are not included in this financial analysis.

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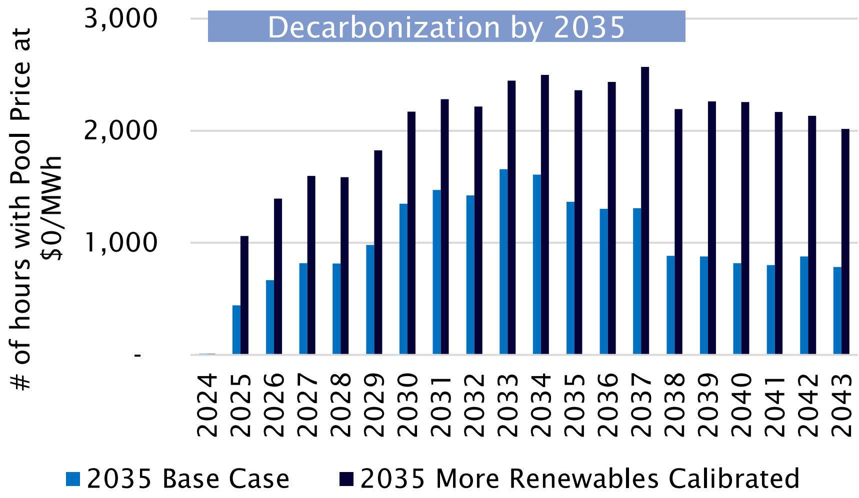
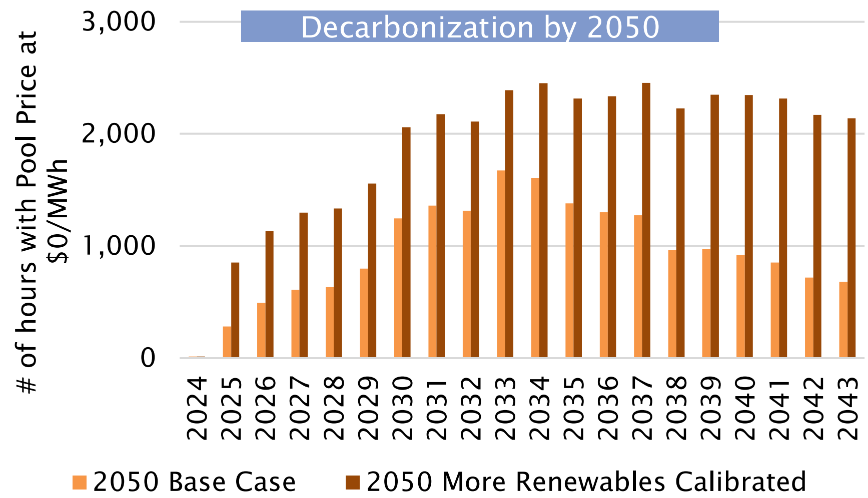
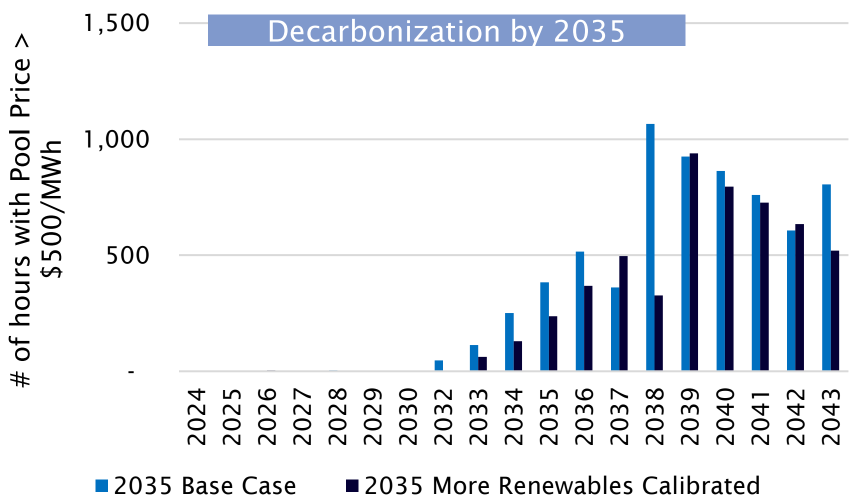
More Renewables Calibrated Cases have significantly more hours at $0/MWh than the Base Cases, which outweighs the impact of more frequent price spikes and unserved load events in the back years

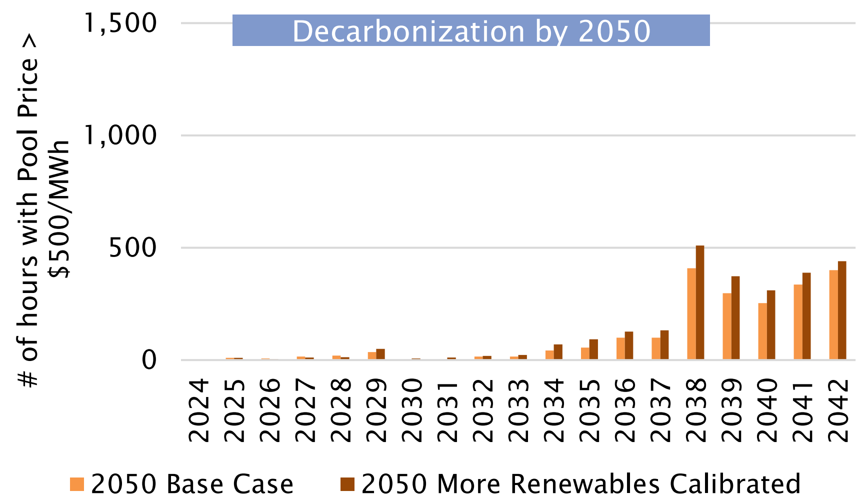
of hours with Pool Prices at $0/MWh (Base Case vs More Renewables Calibrated Case)





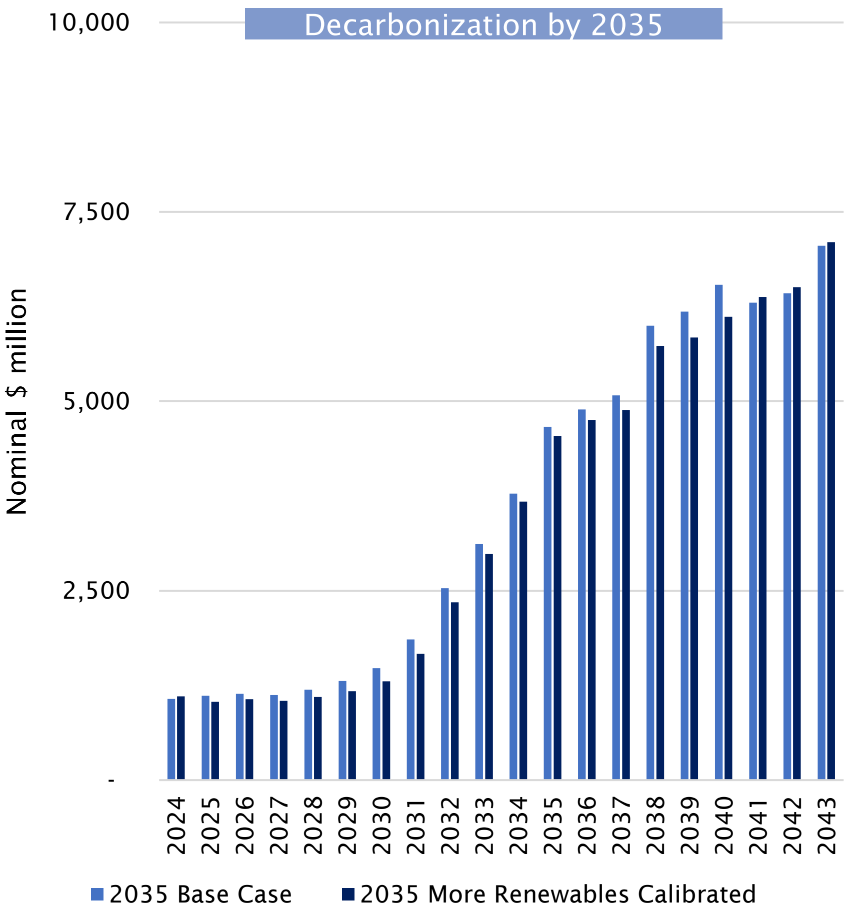
of hours with Pool Prices > $500/MWh (Base Case vs More Renewables Calibrated Case)

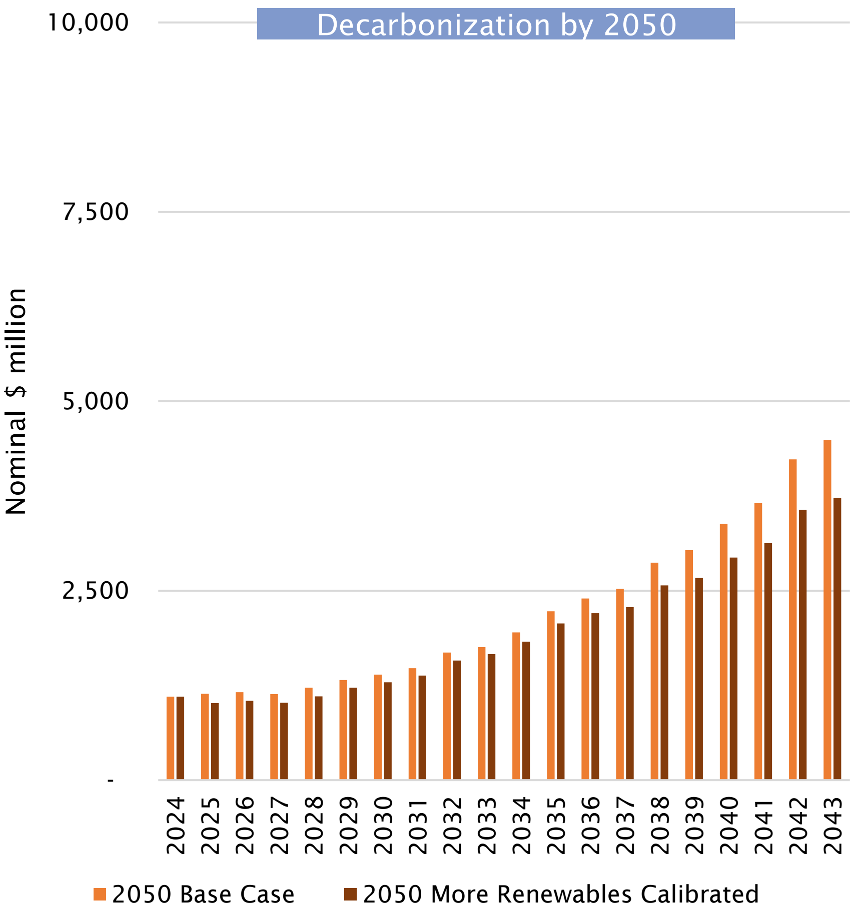




Total production costs (sum of fuel costs + variable O&M cost + carbon cost of all units) are lower with more renewables

Total production cost (Base Case vs More Renewables Calibrated Case, nominal $ million)





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Agenda

3 **Key modeling results**

- Implications of different decarbonization policies
- Implications of additional renewables
- **Implications of lower demand**

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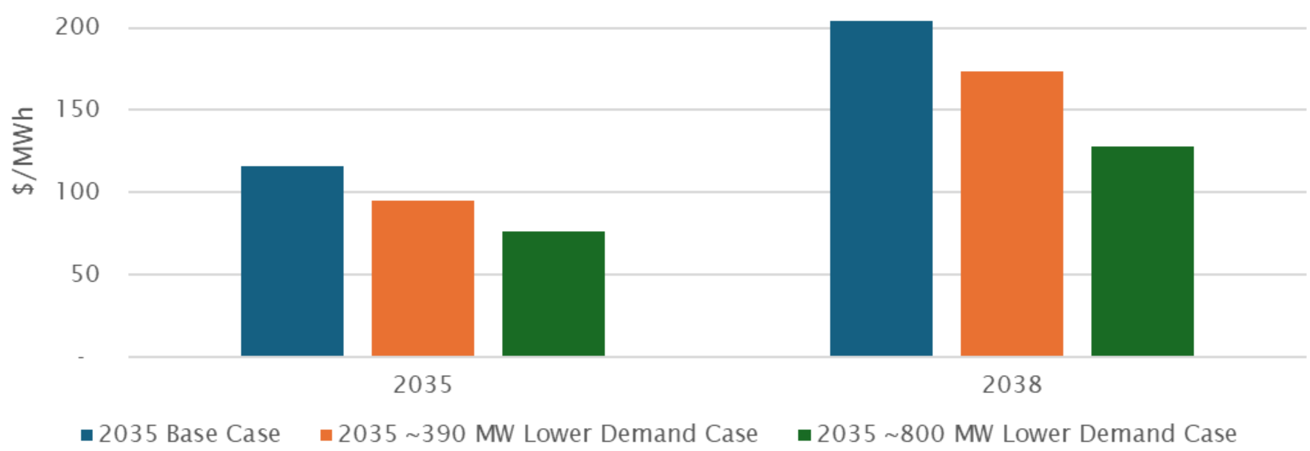
Under the 2035 Base Case conditions, average Pool Prices are sensitive to demand shocks and fall by a much greater percentage than the change in demand

- **The purpose of the Lower Demand Cases is to understand how Pool Prices and supply adequacy change in response to a demand shock**
  - The demand shock is assumed to be unexpected; therefore, LEI kept the supply mix unchanged
  - LEI modeled the lower demand in two sample years (2035 and 2038)
- **When hourly demand is lowered by 3.5% in the ~390 MW Lower Demand Case, average Pool Prices decrease by 15% to 18%**
- **When hourly demand is lowered by 7.2% in the ~800 MW Lower Demand Case, prices are 34% to 37% lower**
- **The relatively large average Pool Price changes indicate that there are many hours where the market clears at the steeper part of the supply curve, reflecting tight supply-demand conditions**

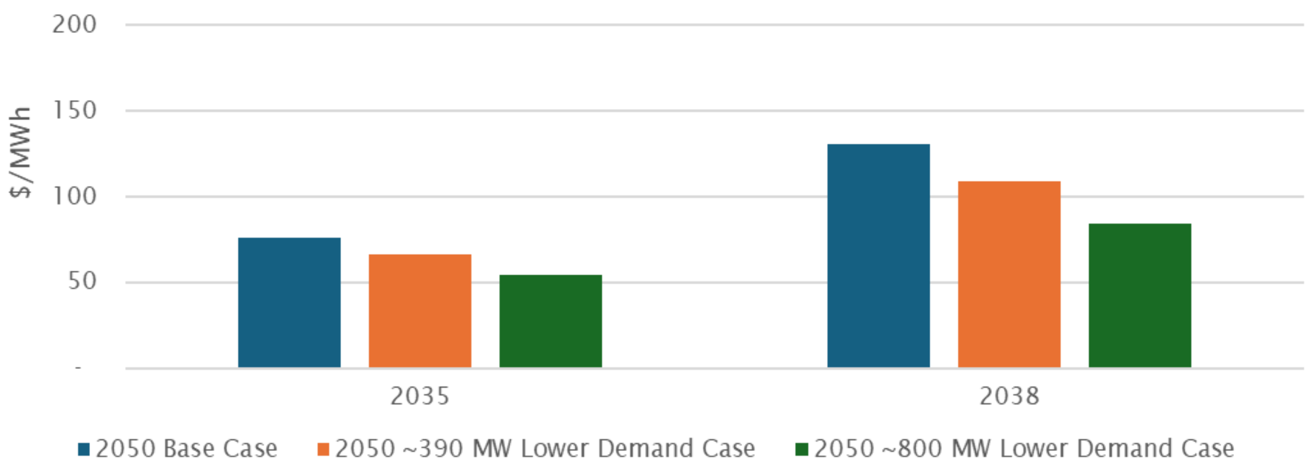
Annual average Pool Price forecast, 2035 Base Case vs 2035 Lower Demand Cases (weather normal), nominal $/MWh



The 2050 Base Case is slightly less sensitive than the 2035 Base Case to demand shocks in 2035, but slightly more sensitive in 2038

- **Under LEI's 2050 ~390 MW Lower Demand Case, the average Pool Price in 2035 is forecasted to be 13% lower than the 2050 Base Case**
  - The percentage change in Pool Price is smaller than the change under the 2035 ~390 MW Lower Demand Case (18%), indicating that supply-demand conditions are less tight under the 2050 Base Case in 2035
- **Under the 2050 ~390 MW Lower Demand Case, the average Pool Price falls by 16% in 2038**
  - The percentage change in Pool Price is slightly larger than the change under the 2035 ~390 MW Lower Demand Case (15%), indicating that supply-demand conditions are tighter under the 2050 Base Case in 2038
- **In the 2050 ~800 MW Lower Demand Case, prices are 29% lower (in 2035) and 36% lower (in 2038)**

Annual average Pool Price forecast, 2050 Base Case vs 2050 Low Demand Case (weather normal), nominal $/MWh



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Glossary of key terms

Ancillary services: Ancillary services include Operating Reserves, Transmission Must-Run, Black Start, Load Shed Services for imports, and Fast Frequency Response. Ancillary services are procured by the AESO to support the reliable operation of the electric grid on a day-ahead basis.

Equivalent Forced Outage Rate on demand ("EFORd"): EFORd measures the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate.

Pool Price: 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. 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.

Scheduled Outage Factor ("SOF"): SOF measures a generation unit's unavailability due to planned or maintenance outages.

Short-run marginal costs ("SRMCs"): 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.

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 (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.

Weather normal: 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 results towards low likelihood events.

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