

2022 System Flexibility Assessment

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1 Summary

The Alberta Electric System Operator (AESO) facilitates a fair, efficient, and openly competitive market for electricity and provides for the safe, reliable, and economic operation of the Alberta interconnected electric system. The *AESO 2022 System Flexibility Assessment* provides a summary of system flexibility needs and capabilities forecast from 2022 to 2031. The data summarized in the figures and tables in this report is provided separately.

System flexibility refers to the ability of the electric system to adapt to dynamic and changing conditions and includes both balancing supply and demand by the hour or minute and operating reliably following a system disturbance. The increasing penetration of variable generation on the electric system will require additional balancing capability to respond to the combined variability of load demand and variable generation, which is referred to as net demand variability. The increasing penetration of variable generation also requires action to ensure performance characteristics of the electric system will be maintained.

The AESO assessed the ability of the electric system to respond to net demand variability under the Reference Case and Clean-Tech Scenario from the *AESO 2021 Long-term Outlook*, which span a range of potential system conditions. The scenarios were modelled through market simulation and dispatch simulation to assess parameters that indicate the ability of the electric system to respond to net demand variability through 2031. In addition, dynamic and system studies examined the electric system's capability to operate reliably in real-time under a range of reasonably expected operating conditions.

The simulation and study results allowed assessment of:

- Ramp distribution
- Ramping capability
- Responses to net demand change
- Forecast uncertainty
- Cumulative absolute dispatch ramp
- Asset on/off cycling
- Supply cushion
- Supply surplus
- Simulated area control error
- Indicative market impact
- System inertia
- Primary frequency response
- System fault response

Key findings

- The flexibility assessment did not identify immediate needs for system flexibility enhancements to respond to net demand variability, provided that market practices continue to reflect the assumptions described in this report.
- Some longer-term trends identified in this assessment—especially in the last half of the forecast period—show that requirements for system flexibility will materially increase to maintain system reliability. The increasing flexibility requirements reflect greater net demand variability due to increasing penetration of variable generation.
- The longer-term trends support the development of incremental enhancements of system flexibility over the next few years through various AESO initiatives, as appropriate, for possible implementation in the mid-2020s.

- Operational simulations suggest some performance characteristics of the electric system are weakening such that action plans are required to ensure frequency excursions can be managed and voltage stability can be maintained.
- If the current strong growth trend of variable generation capacity additions continues, the AESO may need to accelerate the evaluation and development of system flexibility enhancements to respond to net demand variability. The AESO has also investigated recent system events and is implementing initial actions to ensure system reliability will be maintained following a system disturbance.

The AESO is committed to ensuring we have the price signals, technical requirements, and products needed to sustain system reliability as the generation fleet and the industry more broadly transform. We will continue to engage stakeholders as we assess scenarios and explore options to strengthen system flexibility.

The results of the *2022 System Flexibility Assessment* support continued monitoring and assessments of system flexibility. The AESO expects to periodically update the system flexibility assessment to continue efforts to proactively identify when system flexibility may need to be enhanced.

2 Introduction

The AESO monitors and periodically assesses system flexibility capabilities to proactively identify when flexibility may need to be enhanced through tools, processes, standards, rules, etc. as appropriate. If the assessment identifies a requirement for additional flexibility in the future, the AESO would plan to incrementally enhance system flexibility through cost-effective approaches included in various AESO initiatives.

2.1 System flexibility

System flexibility refers broadly to the ability of the electric system to adapt to dynamic and changing conditions and maintain system reliability, and can involve:

- Planning for new generation and transmission resources over a period of years
- Scheduling and dispatching assets to balance supply and demand by the hour or minute
- Responding to transient system conditions within seconds or cycles
- Other capabilities that may be required to maintain system reliability

Over the next several years, the AESO expects that additional system flexibility will be needed to accommodate the effects of increasing variable generation from renewables, more price-responsive load, growing volumes of distributed energy resources, and consumer adoption of new technologies. These changes have the potential to materially impact the reliability of the transmission system. The system flexibility assessment described in this report specifically addresses the ability of the electric system to balance supply and demand through scheduling and dispatching assets, as well as some shorter-term system stability capabilities including inertia and frequency response.

As more variable generation is integrated into the electric system, additional balancing capability may be required to respond to the production variability of the variable generation. The overall variability of the combined load demand and variable generation production is defined as net demand variability, where the change in net demand is determined as change in load demand minus change in variable generation production.

Additional information on net demand variability is provided in Appendix A of this report.

The AESO currently relies on three primary approaches to provide system flexibility to balance supply and demand:

- Energy market dispatch up or down the merit order to address changes in demand, merit order, and interchange schedules with adjacent balancing authorities.
- Regulating reserve ramp up or down, via automatic generation control, to address minute-by-minute changes in demand and variable generation.
- Wind and solar power management that may be used in fast, large ramp-up events to limit wind and solar generation ramping.

Under normal system operation, these approaches do not entirely balance supply and demand in real-time. Any remaining load-interchange-generation imbalances result in instantaneous interchange with adjacent balancing authorities or in deviations in system frequency, both of which are managed in accordance with Alberta reliability standards.

Alberta reliability standards require the AESO to monitor and manage instantaneous interchange within specified limits as part of obligations of the AESO—and other members of the Western Electricity Coordinating Council (WECC)—to effectively and efficiently mitigate risks to the reliability and security of the Western Interconnection. (The Western Interconnection is the area comprised of those portions of western Canada, northern Mexico, and the western United States in which members of WECC operate synchronously connected transmission systems.)

The use of interchange is governed by Alberta reliability standards and through WECC, of which the AESO is a member.

In addition, increasing variable generation and other changing conditions can impact the electric system's capability to maintain system stability in real-time. This flexibility assessment includes discussion of three aspects of system stability: system inertia, primary frequency response, and system fault response.

2.2 Monitoring and forecasting system flexibility

The AESO includes monitoring of historical system flexibility parameters regarding market and system operation in its annual market statistics reports, most recently in the *2021 Annual Market Statistics* report¹ published in March 2022, which includes information on net demand ramps, ratio of variable generation to load, load forecast uncertainty, wind and solar power forecast uncertainty, and asset on/off cycling.

The AESO will continue to monitor these and other parameters as applicable to understand the changing flexibility needs of the system as variable generation increases.

The AESO has previously assessed forecast net demand variability and whether the electric system has sufficient flexibility in the *Dispatchable Renewables and Energy Storage* report² published in May 2018 and in the *2020 System Flexibility Assessment*³ published in July 2020.

In this system flexibility assessment report, the AESO provides information on forecast system flexibility parameters, including several of the historical parameters included in the 2021 Annual Market Statistics report. This assessment builds on previous assessments and reflects changes to the market since those previous assessments were completed, including the release of the AESO 2021 Long-term Outlook⁴ (in June 2021) and ongoing changes to supply and demand in the energy market.

This current assessment differs from the 2020 System Flexibility Assessment in several areas, notably:

- Inclusion of energy storage assets and small distributed energy resources, consistent with scenarios in the *AESO 2021 Long-term Outlook*.
- Inclusion of greater amounts of wind and solar generating assets, also consistent with scenarios in the *AESO 2021 Long-term Outlook*.
- Use of more recent data for characteristics and profiles of generating assets.
- Improved profiling of solar generating assets.

¹ Available at <https://www.aeso.ca/assets/Uploads/market-and-system-reporting/2021-Annual-Market-Stats-Final.pdf>

² Available at <https://www.aeso.ca/assets/Uploads/grid-related-initiatives/energy-storage/AESO-Dispatchable-Renewables-Storage-Report-May2018.pdf>

³ Available at <https://www.aeso.ca/assets/Uploads/AESO-2020-System-Flexibility-Assessment-FINAL-jul-17.pdf>

⁴ Available at <https://www.aeso.ca/assets/Uploads/grid/lt/2021-Long-term-Outlook.pdf>

- Inclusion of additional results for average response delay, system flexibility responses, supply cushion and supply surplus.
- Inclusion of operational simulation results for system inertia, primary frequency response, and system fault response.

The AESO plans to complete periodic updates to system flexibility assessments to reflect the ongoing evolution of the transmission system, changes in generation and loads, and the adoption of new technologies. Future system flexibility updates will also be informed by forward-looking information the AESO provides, such as future Long-term Outlook forecasts and the Net-Zero Emissions Pathways initiative. The system flexibility updates will continue the AESO's efforts to proactively identify when system flexibility may need to be enhanced.

The data used for the figures and tables in this report is provided separately. The values represented in the figures and tables, as well as additional information, are available in that data.

3 Assessment methodology

The AESO assessed the ability of the electric system to respond to net demand variability under different scenarios—including both load and generation forecasts—that span a range of potential system conditions. The system flexibility assessment in this report used a market and dispatch simulation methodology similar to that of the previous system flexibility assessment. The AESO also used operational simulations to examine three shorter-term aspects of system stability: system inertia, primary frequency response and system fault response.

The assessment methodology is described in more detail below.

3.1 Scenario-based analysis for market and dispatch simulations

The AESO used two scenarios to simulate the ability of the electric system to balance supply and demand in 10-minute intervals over a 10-year forecast period. A reference case was used to establish results from a baseline analysis, and analysis of an additional scenario provided insights into potential impacts from different load and generation forecasts. The scenario-based analysis examines the impact of key known uncertainties to understand if and when system flexibility may need to be enhanced.

This system flexibility assessment is based on the Reference Case and Clean-Tech Scenario included in the *AESO 2021 Long-term Outlook* published in June 2021 as the foundation for load and generation assumptions.

- The Reference Case from the *2021 Long-term Outlook* is used as the Reference Case in this system flexibility assessment.
- The Clean-Tech Scenario from the *2021 Long-term Outlook* is used as a scenario to assess system flexibility with higher penetration of renewable generation and energy storage assets.

As system flexibility requirements generally increase as more renewable generation is integrated into the electric system, the Clean-Tech Scenario was selected as the scenario from the *2021 Long-term Outlook* that included the largest amounts of renewable generation and distributed energy resources.

Analysis of the Reference Case and the Clean-Tech Scenario permits assessment of a range of net demand variability conditions. The AESO will consider additional scenarios for inclusion in future system flexibility assessments.

The Reference Case and Clean-Tech Scenario assessments were prepared for a 10-year forecast period from 2022 to 2031. The AESO considers that the results over the 10-year period allow proactive identification of potential flexibility concerns, with sufficient time for design and implementation of approaches to address any emerging issues. The 10-year forecast period will be moved forward in the periodic flexibility assessment updates that were mentioned previously in section 2.2. Finally, limiting the assessment to 10 years also avoids the increased uncertainty that accompanies real-time dispatch simulation over longer timeframes.

3.1.1 Reference Case

The Reference Case used in this assessment is the Reference Case included in the *AESO 2021 Long-term Outlook* and is the AESO's main corporate forecast for long-term load growth and generation development in Alberta.

In the Reference Case in the *2021 Long-term Outlook*, load is forecasted to grow at a compound annual growth rate of 0.5 per cent until 2041. This is approximately one-quarter the rate of growth Alberta experienced in the past 20 years.

The generation outlook provides a view of what Alberta's competitive electricity market would be expected to develop over the forecast period to meet forecast demand reliably.

Approximately 4.6 gigawatt (GW) of new generation capacity is expected to develop by 2031 for a total Alberta capacity of 21.8 GW in 2031.

- **Natural gas-fired generation** will become the predominant generation source as coal-fired capacity is expected to be retired or converted to natural gas by 2025, with a peak of 4.3 GW of converted coal-fired capacity achieved in 2022.
- **Renewable generation** will continue to develop to reflect benefits from the diversified revenue available from the sale of renewable attributes that are additional to their energy income. The Reference Case includes the addition of 2.7 GW of renewable generation capacity by 2031.

The Reference Case generation forecast indicates that the market will incent or enable the level of generation investment that is required to meet long-term resource adequacy. The Reference Case generation forecast includes capacity additions for specific generation technologies based on the relative economics of the technologies.

More information on the Reference Case is available in the *AESO 2021 Long-term Outlook*.

3.1.2 Clean-Tech Scenario

The Clean-Tech Scenario used in this assessment is the Clean-Tech Scenario included in the *AESO 2021 Long-term Outlook*. The Clean-Tech Scenario assumes that Alberta's economy will start to shift away from oil and gas and towards other more-diversified sectors to fuel economic growth. However, natural gas-fired generation will be the predominant generation source in the Clean-Tech Scenario, and oil and gas will remain a significant contributor to Alberta's economy through the 10-year forecast period.

In the Clean-Tech Scenario, similar to the Reference Case, load is forecast to grow at a compound annual growth rate of 0.5 per cent until 2041. As well, the Clean-Tech Scenario includes significant small distributed energy resources of less than 5 megawatts (MW) capacity as an offset within the load data; totaling 1.2 GW of distributed energy resource capacity by 2031, of which 1.0 GW is solar generation.

The Clean-Tech Scenario tests greater generation diversification with higher penetration of wind and solar generation. Under the Clean-Tech Scenario, approximately 5.5 GW of new generation capacity is expected to develop by 2031 for a total Alberta capacity of 22.7 GW in 2031. Solar generation additions account for most of the increase compared to the Reference Case. Capacity additions also include 0.9 GW of energy storage assets by 2031. The Clean-Tech Scenario generation forecast includes capacity additions for specific generation technologies at levels different from the Reference Case.

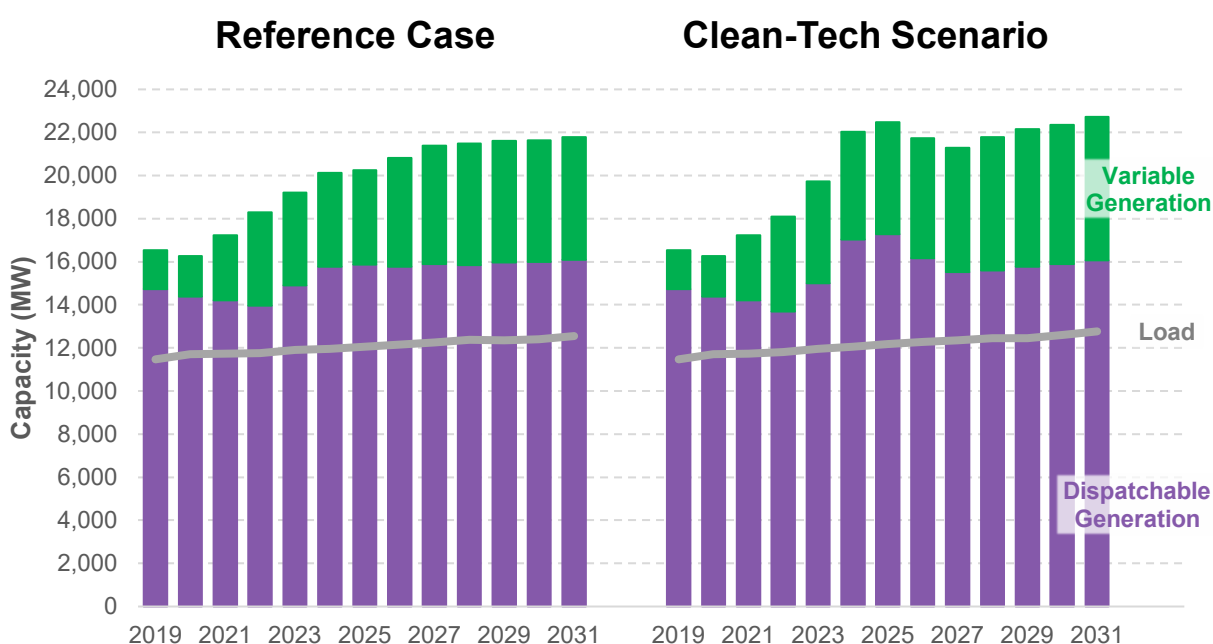
More information on the Clean-Tech Scenario is available in the *AESO 2021 Long-term Outlook*.

3.1.3 Load and generation capacity forecast for Reference Case and Clean-Tech Scenario

As discussed above in section 2, net demand variability reflects the combined impact of load and variable generation. The AESO responds to net demand variability using dispatchable generation, including through energy market dispatch and through the provision of regulating reserve by dispatchable generation. Figure 3-1 illustrates the annual load and generation capacity, differentiated between variable and dispatchable generation, for the Reference Case and Clean-Tech Scenario.

In Figure 3-1, dispatchable generation includes coal-fired, gas-fired steam (also referred to as coal-to-gas conversions), cogeneration, combined cycle, simple cycle, hydro, energy storage, and other dispatchable generation. Variable generation includes wind, solar, and solar-with-storage generation. Figure 3-1 does not include intertie capacity.

Figure 3-1 – Peak Alberta internal load and generation capacity by scenario



Note: Capacities for 2019-2021 are actual amounts; capacities for 2022-2031 are forecast amounts; generation excludes distributed energy resources (DERs) of less than 5 MW

3.1.4 Net-Zero Emissions Pathways initiative

Throughout 2022 the AESO will be undertaking work collaboratively with stakeholders to understand the potential pathways and implications to achieve a net-zero emissions electricity sector in Alberta. Building upon the Clean-Tech Scenario of the 2021 Long-term Outlook, the AESO will explore net-zero pathways from the perspective of achieving emissions policy objectives within the context of the existing market framework and maintaining a reliable electric system. As the net-zero emissions pathways initiative is on-going, a net-zero emissions scenario is not included in this flexibility assessment.

The Net-Zero Emissions Pathways initiative includes publication of potential pathways to a net-zero electricity system in Alberta along with qualitative and quantitative analysis for select scenarios. However, the initiative’s purpose is to seek to understand and to examine the potential pathways and implications to achieving a net-zero emissions electricity sector in Alberta, rather than to create a specific forecast scenario to achieve a net-zero emissions target.

Following publication of the Net-Zero Emissions Pathways report, the AESO will consider whether additional flexibility information should be provided to reflect the analysis and findings of the Net-Zero Emissions Pathways initiative, either in its next flexibility assessment, in a supplement to this assessment, or as part of another AESO initiative.

More information on the Net-Zero Emissions Pathways initiative is available on the AESO website.⁵

3.2 Condition analysis for operational simulations

The AESO used a selection of operating conditions for dynamic simulations and system studies of flexibility indicators. The simulations and studies examined changes expected over the forecast period using a range of credible operating conditions under which different combinations of load, import, inertia, and generator response could potentially result in system instability, as well as conditions more typically experienced on the transmission system.

The operational simulations represented the range of conditions that are reasonably expected in the Reference Case and Clean-Tech Scenario over the 10-year forecast period. However, the operational simulations did not assess the frequency or probability of those conditions occurring under a specific scenario or in a specific year.

3.3 Analytical approach

The Reference Case and Clean-Tech Scenario described previously in section 3.1 were modelled through market simulation to create hourly load and generation profiles from 2022 to 2031. The hourly profiles were then further modelled through dispatch simulation to create minute-level profiles to assess parameters that will indicate the ability of the electric system to respond to net demand variability to 2031. Conditions for operational simulations were selected to be representative of the range of conditions in the Reference Case and Clean-Tech Scenario.

Figure 3-2 illustrates the analytical approach used for the system flexibility assessment.

3.3.1 Hourly market simulation

Aurora market modelling software was used to simulate the supply and demand characteristics of the Reference Case and Clean-Tech Scenario. The Aurora software is a cost-production model that applies economic principles, offer and dispatch logic, and offer strategies to model the relationships of supply, demand, and interchange. The software capabilities encompass multiple-year, long-term forecasting (for generator capacity additions) to hourly availability of generation for dispatch.

The market simulation incorporates forecast load, generation development, observed historical unit characteristics including outages, and offer behavior to simulate an hourly market. The market simulation primarily provides an hourly merit order over the forecast period that is then used in the dispatch simulation to assess future system flexibility.

3.3.2 Real-time dispatch simulation

The AESO's operational dispatch simulation tool was used to simulate the real-time dispatch expected to result from the hourly merit order results of the market simulation. The dispatch simulation tool applies observed historical asset characteristics, including ramping and dispatch response, to model minute-by-minute system operation.

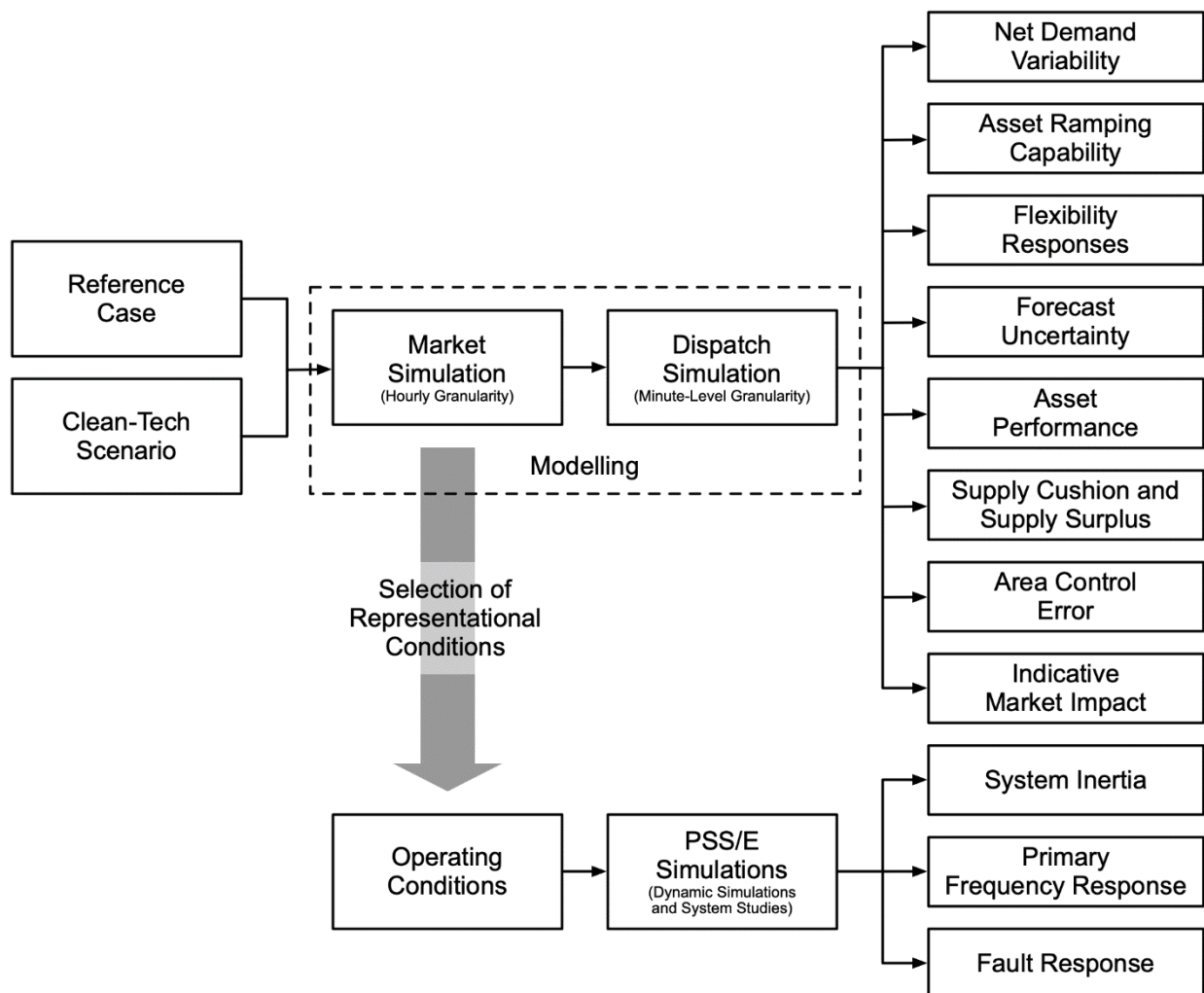
⁵ Available at <https://www.aeso.ca/market/net-zero-emissions-pathways/>.

The dispatch simulation reflects timeframes from hour-ahead (for short-term forecasts of load and variable generation) to real-time (for dispatch and response of assets and regulating reserve). The dispatch simulation includes simplified real-time dispatch logic and practices, as well as market operation practices. The dispatch simulation allows observation of performance impacts of the market simulation.

The dispatch simulation:

- Models both the intra-hour energy market dispatch and the regulating reserve used to provide system flexibility.
- Models the instantaneous interchange with adjacent balancing authorities.
- Assumes the Alberta electric system remains continuously synchronously interconnected to the Western Interconnection and does not model islanded operation.

Figure 3-2 – System flexibility analytical approach



3.3.3 Operational simulations

In addition to market and dispatch simulations, the AESO completed operational simulations to identify how the generation diversification expected during the next ten years may potentially impact the reliability of the transmission system. The AESO used industry-standard PSS/E power system simulation software from Siemens for dynamic simulations and system studies.

The dynamic simulations examined system inertia and primary frequency response impacts after a sudden loss of imports, which would also be representative of impacts after a sudden loss of supply in Alberta under islanded conditions. (Impacts would be significantly less after loss of supply in Alberta when Alberta is synchronously interconnected to the Western Interconnection.)

Steady-state studies also examined system fault response on the electric system during a power flow excursion or system disturbance. System fault response is assessed by evaluating short circuit levels which are impacted when generation connects to the transmission system using grid-following inverters. Grid-following inverters are currently the dominant technology used to connect variable generation in Alberta.

3.3.4 Simulation assumptions

The market and dispatch simulations completed for the system flexibility assessment included the following assumptions both to maintain comparability between scenarios and over the analysis period, and to allow the analysis to be completed within a reasonable timeframe.

- Dispatchable generating assets were modelled using characteristics based on observations in 2020 and 2021, including:
 - average time to respond to dispatches
 - average ramp-up and ramp-down rates
 - minimum stable generation levels
 - average inertia by asset under normal operation
- Gas-fired steam (referred to as coal-to-gas conversion in the *AESO 2021 Long-term Outlook*) assets were modelled using characteristics based on recent observations and on estimates reflecting recently observed values and industry discussion.
- Wind generating assets were modelled by hour and minute using historical generation profile data for 2018 and scaling the historical profiles by year to reflect forecast wind generation capacity and expected geographic diversity.
- Solar generating assets were modelled by hour and minute using solar generation daily profile data available for 2020 and 2021, matching those daily profiles to historical solar daily profiles available for 2018 to synchronize weather conditions, and scaling the weather-matched daily profiles by year to reflect forecast solar generation capacity and expected geographic diversity (based on diversity effects observed in 2020 and 2021 solar generation data).
- Energy storage assets were modelled with charge and discharge profiles based on prices in the energy market simulation, with the same profiles used in the dispatch simulation.
- Load was modelled by hour and minute using historical load profile data from 2018 and scaling the historical profiles by year to reflect forecast load levels.
- Small distributed energy resources of less than 5 MW were included as an offset using resource-specific profiles within the hourly load profile data and were not separately modelled as generating assets in the dispatch simulation.

- Wind and solar power management was allocated over all wind and solar generation facilities rather than to specific individual facilities, to simplify wind and solar power management within the dispatch simulation.
- Scheduled exports and imports were based on a normal water year, which reflects long-term average precipitation in the Pacific Northwest.
- Regulating reserve was modelled based on current day-ahead procurement practices, reflecting the volumes determined by the AESO to be required to meet the needs of the electric system in accordance with applicable reliability standards and operational benchmarks.
- Planned outages for larger generating assets and forced outages for thermal generating assets and energy storage assets were modelled within the market simulation based on asset-specific and technology-specific historical observations.
- Asset dispatch was simulated with no transmission constraints.
- System controller dispatch practice was modelled throughout the analysis period based on simplified current observed practice.
- System controller dispatch was modelled as occurring on the 10-minute marks during an hour (that is, at times HH:00, HH:10, HH:20, HH:30, HH:40, and HH:50) to simplify actual dispatch which may occur during any minute of an hour.
- Contingency reserve was not modelled as the dispatch simulation is intended to represent normal system operation.
- Out-of-market dispatches, including those for transmission must-run, dispatch down service, transmission constraint management, or supply surplus, were not included in the simulation.

The operational simulations completed for the system flexibility assessment included the following assumptions.

- Operating conditions represented different combinations of load, import, inertia, and generator response that are reasonably expected in the Reference Case and Clean-Tech Scenario over the forecast period.
- Generating assets reflected a range of typical characteristics and performance as currently observed and as expected to be likely to occur over the forecast period.

The specific years of historical data identified in the assumptions above and used in the modelling reflect the most recent year for which complete data was available for the AESO's development of its market and dispatch simulations for use in this system flexibility assessment. The simulation assumptions will continue to be reviewed and updated where appropriate in future system flexibility assessments.

Actual load and generating asset operation, dispatch practice, and other characteristics will differ from these assumptions to varying degrees. Differences from the assumptions will result in actual market, dispatch, and operational outcomes that differ from the simulations completed for the system flexibility assessment. In particular, conditions that do not reflect normal operation, including transmission constraints and out-of-market dispatches, are not included in the simulations and can materially affect outcomes in real-time operations.

4 Market and dispatch simulation results

As discussed in the preceding section, the AESO completed market and dispatch simulations to evaluate the ability of the electric system to balance supply and demand to accommodate the effects of increasing variable generation and other factors. The AESO analyzed the results of the simulations to assess the changes to flexibility parameters over the 10-year forecast period and between the Reference Case and Clean-Tech Scenario. The flexibility parameters that were assessed in the simulation results included ramp distribution, ramping capability, forecast uncertainty, asset on/off cycling, supply cushion, supply surplus, and area control error distribution.

4.1 Ramp distribution

Net demand variability includes imbalances resulting from changes in load and changes in variable generation. Variability is measured over an interval as the increase or decrease, in MW, that is attributable to Alberta internal load, to variable generation, or to net demand (which is Alberta internal load demand minus variable generation production). The increase or decrease is usually referred to as a ramp up or down, respectively.

The AESO examined the size and frequency of variability of load, variable generation, and net demand over both 10-minute and 60-minute intervals. As system controller dispatch was modelled as occurring on the 10-minute marks during an hour, net demand variability over 10-minute intervals was primarily addressed in the simulations through regulating reserve ramping up or down, via automatic generation control, and through instantaneous interchange with adjacent balancing authorities. Net demand variability over 60-minute intervals was primarily addressed in the simulation through energy market dispatch up or down the merit order.

Figure 4-1 provides the size and frequency of 10-minute ramps of Alberta internal load, variable generation, and net demand from the simulations for 2022, 2026, and 2031 in the Reference Case and Clean-Tech Scenario. Figure 4-2 provides similar information for 60-minute ramps. In both figures, the horizontal axis is the size of the ramp up or down over the interval, in incremental 10 MW bins, while the vertical axis is the number of intervals with ramps of the size in each bin.

The figures show that both 10-minute and 60-minute ramps become larger and larger ramps become more frequent:

- For each of Alberta internal load, variable generation, and net demand.
- In later years in both the Reference Case and Clean-Tech Scenario.
- To a greater extent in the Clean-Tech Scenario compared to the Reference Case.

The increase in size and frequency of ramps is attributed primarily to the following factors:

- For **Alberta internal load**, the larger capacity of small distributed energy resources of less than 5 MW (particularly in the Clean-Tech Scenario) which were included as an offset within the load profile data in later years of the forecast period.
- For **variable generation**, the larger capacity of variable generation in later years of the forecast period and in the Clean-Tech Scenario.
- For **net demand**, the increase in frequency of larger variable generation ramps, combined with the increase in frequency of larger load ramps.

Table 4-3 summarizes the average size and frequency of large 10-minute and 60-minute ramps of Alberta internal load, variable generation, and net demand in both scenarios.

Figure 4-1 – Distribution of 10-minute ramps for load, variable generation, and net demand by scenario

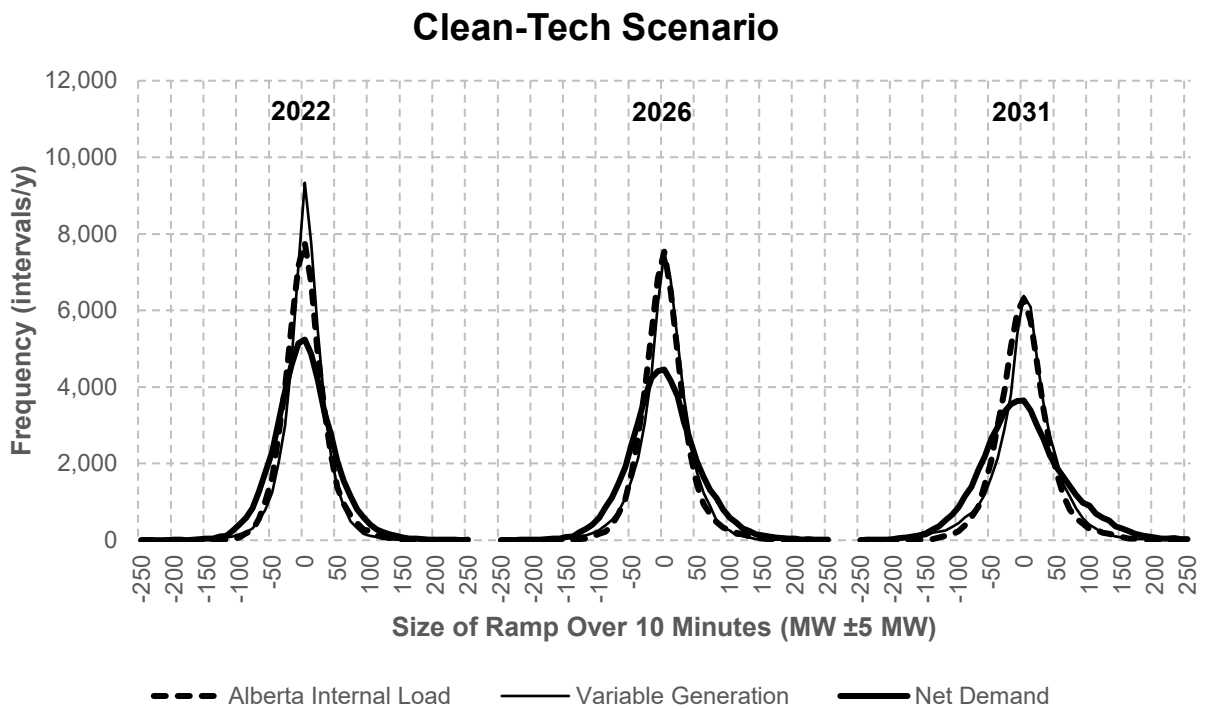
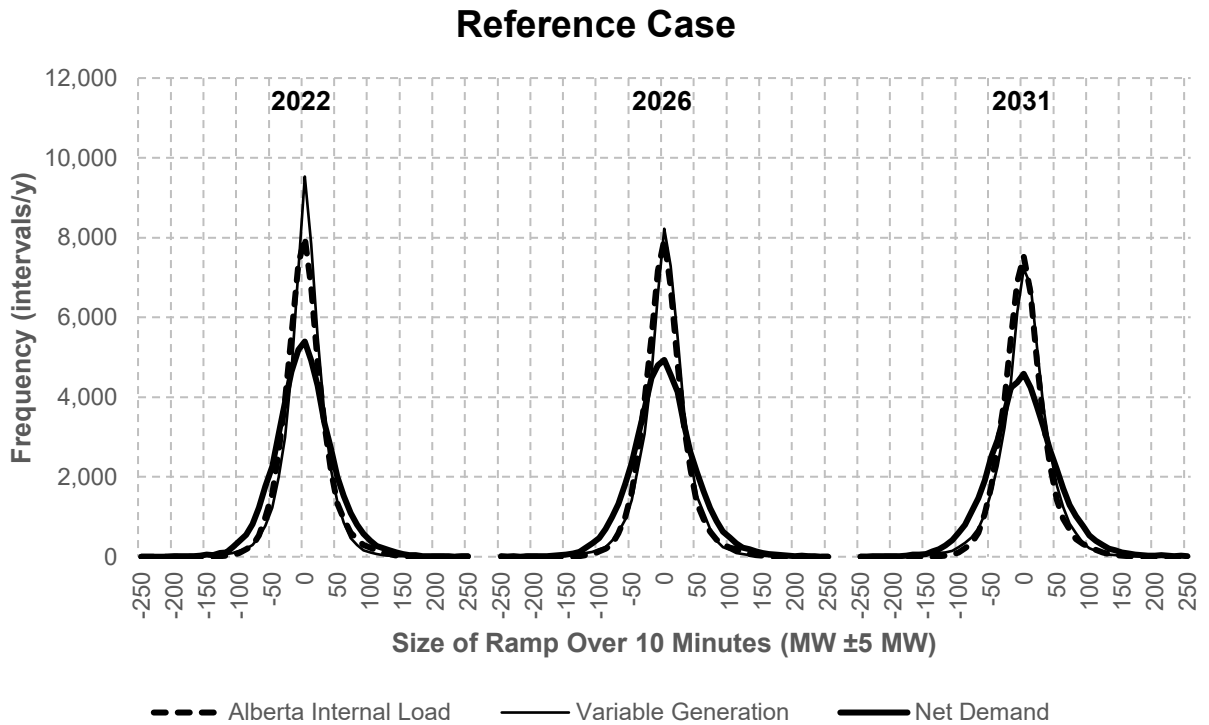


Figure 4-2 – Distribution of 60-minute ramps for load, variable generation, and net demand by scenario

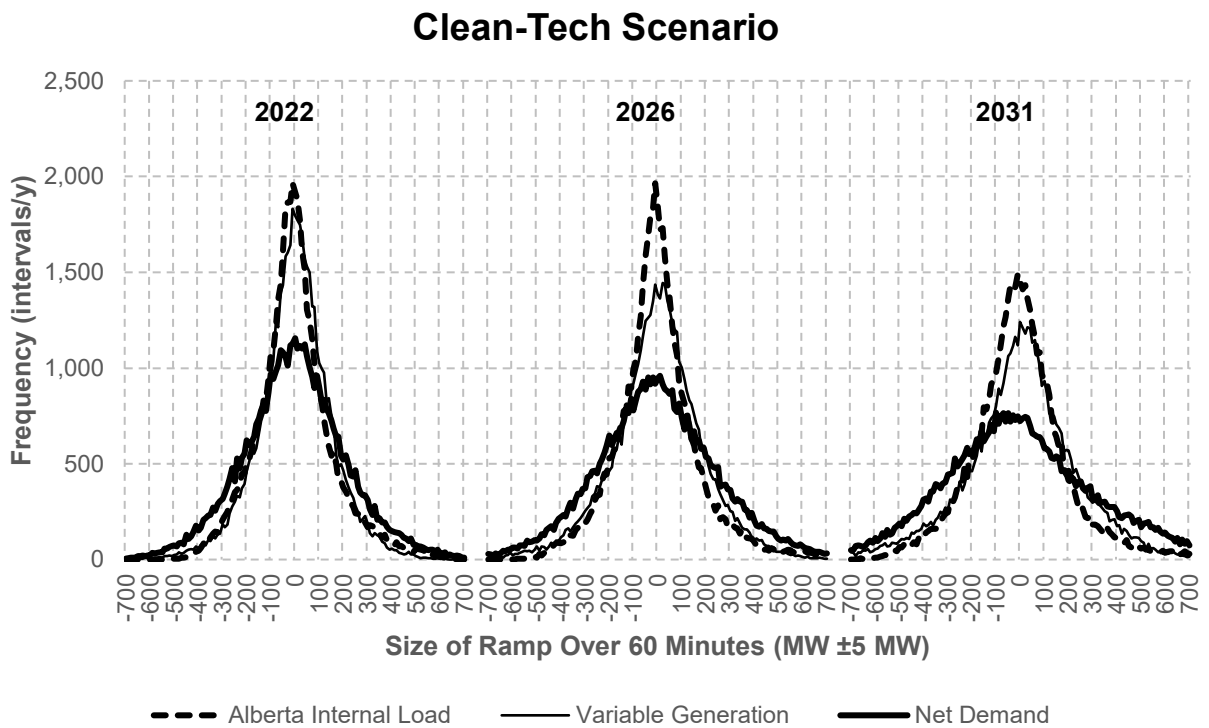
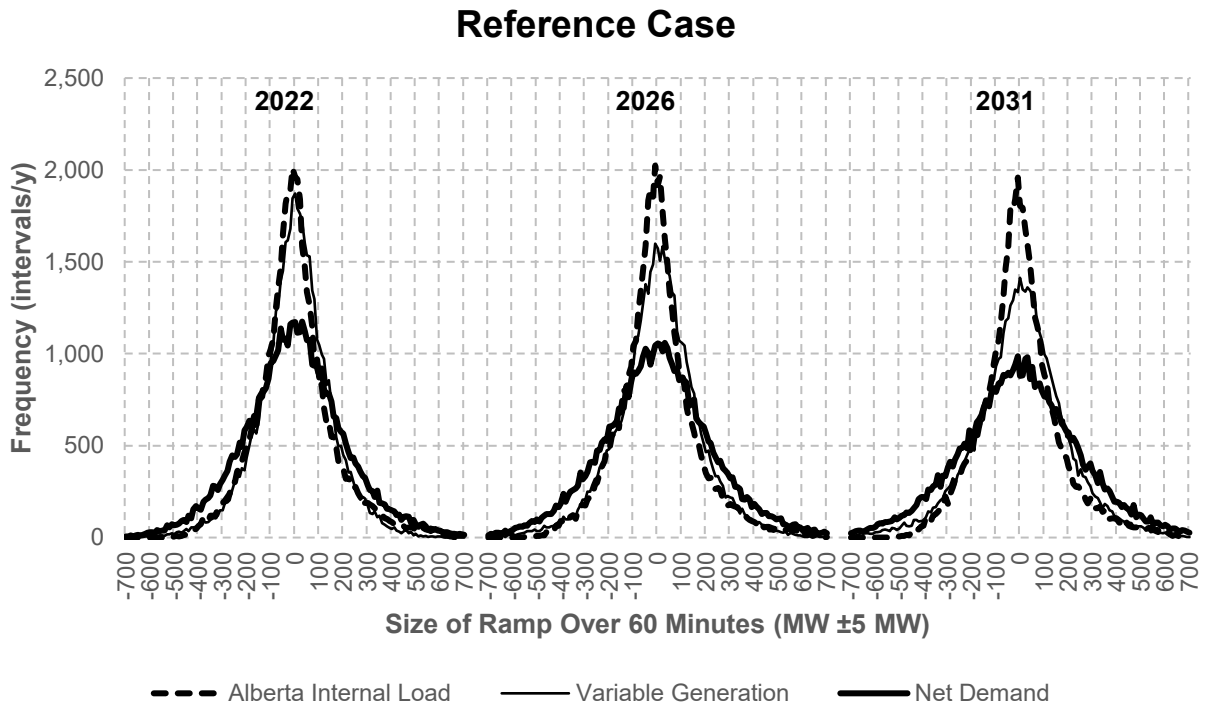


Table 4-3 – Average size and frequency of large 10-minute and 60-minute ramps for load, variable generation, and net demand by scenario

	Alberta Internal Load			Variable Generation			Net Demand		
Large Short Ramps (± 50 MW or more over 10 minutes, starting every 10 minutes during year)									
Reference Case	2022	2026	2031	2022	2026	2031	2022	2026	2031
Average Size (MW)	71	72	72	78	81	83	79	82	85
Frequency (intervals/y)	6,296	6,629	6,882	5,680	7,249	8,936	12,840	14,598	16,367
Frequency (% of total intervals)	12.0%	12.6%	13.1%	10.8%	13.8%	17.0%	24.4%	27.8%	31.1%
Clean-Tech Scenario	2022	2026	2031	2022	2026	2031	2022	2026	2031
Average Size (MW)	70	74	77	78	82	89	79	85	93
Frequency (intervals/y)	6,340	7,381	9,987	5,866	9,108	12,824	13,153	16,695	21,824
Frequency (% of total intervals)	12.1%	14.0%	19.0%	11.2%	17.3%	24.4%	25.0%	31.8%	41.5%
Large Long Ramps (± 100 MW or more over 60 minutes, starting every 10 minutes during year)									
Reference Case	2022	2026	2031	2022	2026	2031	2022	2026	2031
Average Size (MW)	211	214	214	201	216	232	244	259	276
Frequency (intervals/y)	22,694	22,921	23,525	22,839	25,787	28,150	31,298	33,144	34,915
Frequency (% of total intervals)	43.2%	43.6%	44.8%	43.5%	49.1%	53.6%	59.6%	63.1%	66.4%
Clean-Tech Scenario	2022	2026	2031	2022	2026	2031	2022	2026	2031
Average Size (MW)	210	220	236	203	231	267	246	275	327
Frequency (intervals/y)	23,002	23,788	27,299	23,188	27,762	31,111	31,731	34,948	38,363
Frequency (% of total intervals)	43.8%	45.3%	51.9%	44.1%	52.8%	59.2%	60.4%	66.5%	73.0%
Very Large Long Ramps (± 500 MW or more over 60 minutes, starting every 10 minutes during year)									
Reference Case	2022	2026	2031	2022	2026	2031	2022	2026	2031
Average Size (MW)	556	567	561	579	584	604	596	609	625
Frequency (intervals/y)	490	594	569	295	706	1,211	1,525	2,359	3,197
Frequency (% of total intervals)	0.9%	1.1%	1.1%	0.6%	1.3%	2.3%	2.9%	4.5%	6.1%
Clean-Tech Scenario	2022	2026	2031	2022	2026	2031	2022	2026	2031
Average Size (MW)	547	583	611	579	598	633	595	619	647
Frequency (intervals/y)	435	776	1,431	332	1,096	2,637	1,595	3,101	6,616
Frequency (% of total intervals)	0.8%	1.5%	2.7%	0.6%	2.1%	5.0%	3.0%	5.9%	12.6%

For the 10-minute ramps of net demand in the Reference Case illustrated in Figure 4-1, the average size of large ramps up and down (of at least ± 50 MW) increases by about eight per cent over the forecast period, and the frequency of those large ramps increases by about 27 per cent. In the Clean-Tech Scenario, the average size of large ramps (of at least ± 50 MW) increases by about 18 per cent over the forecast period, and the frequency of those large ramps increases by about 66 per cent. The increase in size and frequency of large 10-minute ramps indicates increasing need for regulating reserve and instantaneous interchange to respond to net demand variability in later years and in the Clean-Tech Scenario.

For the 60-minute ramps of net demand in the Reference Case illustrated in Figure 4-2, the average size of very large ramps up and down (of at least ± 500 MW) increases by about five per cent over the forecast period, and the frequency of those very large ramps approximately doubles. In the Clean-Tech Scenario, the average size of very large ramps (of at least ± 500 MW) increases by about nine per cent over the forecast period, and the frequency of those very large ramps approximately triples. The increase in size and frequency of very large 60-minute ramps indicate increasing need for dispatchable generation capacity to respond to net demand variability in later years and in the Clean-Tech Scenario.

The increases in size and frequency of larger net demand ramps in this flexibility assessment is substantially greater than that observed in the 2020 flexibility assessment (which was about a five per cent increase in size and a 10 to 30 per cent increase in frequency of large net demand ramps of at least ± 50 to ± 100 MW). The AESO attributes the increases primarily to the:

- Larger capacity of renewable generation and the small distributed energy resources in both the Reference Case and Clean-Tech Scenario.
- Improved solar generation profile used for the simulations, as discussed previously in section 3.3.

The increases in size and frequency of larger net demand ramps suggest that regulating reserve and instantaneous interchange with adjacent balancing authorities will be increasingly relied on to respond to net demand changes and that system controllers may be more challenged to respond to net demand changes through energy market dispatch.

4.2 Ramping capability

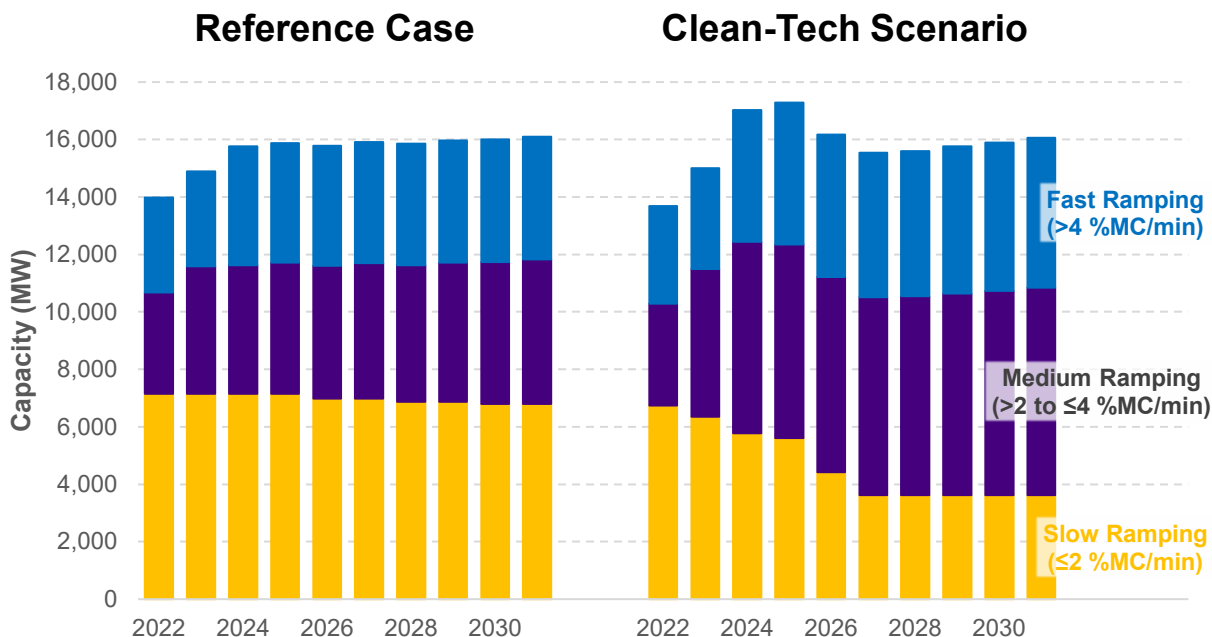
The net demand variability discussed in the previous section requires the electric system to respond within a timeframe of a few minutes to an hour or two. Dispatchable generation provides the balancing capability to match the size, speed, and frequency of the net demand ramps.

As noted in section 4.1, large net demand ramps increase in size and frequency during the forecast period. Dispatchable generation with sufficiently fast ramping and short response delay can match larger ramps that occur with greater frequency.

Figure 4-4 illustrates the average ramp rates of the dispatchable generation capacity simulated in the Reference Case and Clean-Tech Scenario. Ramp rate is measured as the average increase in output a generating asset can achieve in a 10-minute interval, expressed as a percentage of the generating asset's maximum capability per minute (%MC/min). The column segments in Figure 4-4 indicate the total generating capacity, in MW, in each of three ramp rate ranges:

- **Fast ramping**, capable of increases of more than four per cent of maximum capability per minute (primarily some cogeneration, simple cycle generation, hydro generation, and energy storage).
- **Medium ramping**, capable of increases of more than two per cent up to four per cent of maximum capability per minute (primarily some cogeneration and some combined cycle generation).
- **Slow ramping**, capable of increases of up to two per cent of maximum capability per minute (primarily coal generation, gas-fired steam generation, some cogeneration, and some combined cycle generation).

Figure 4-4 – Ramp rates of dispatchable generation by scenario



Fast ramping generating capacity increases moderately over the forecast period in both the Reference Case and Clean-Tech Scenario. The increase results from fast ramping cogeneration and energy storage capacity additions over the forecast period. Increases in fast ramping generating capacity provide additional flexibility to respond to the increasing frequency of large net demand ramps illustrated in Figures 4-1 and 4-2.

Medium ramping generating capacity increases moderately over the forecast period in the Reference Case and increases significantly over the forecast period in the Clean-Tech Scenario. The increase results from medium ramping cogeneration and medium ramping combined cycle capacity additions over the forecast period. Increases in medium ramping generating capacity provide limited additional flexibility to respond to larger net demand ramps.

Slow ramping generating capacity remains relatively constant over the forecast period in the Reference Case and decreases significantly over the forecast period in the Clean-Tech Scenario. The decrease in the Clean-Tech Scenario results from coal and gas-fired steam generation capacity reductions over the forecast period. The reduction in slow ramping generation capacity is offset by the increases in medium and fast ramping capacity discussed above, which provide flexibility to respond to the frequency of larger net demand ramps.

The ramping capability of dispatchable generation is also affected by the response delay from when a dispatch direction is issued to a generating asset to when the asset operator starts to ramp the asset to the directed dispatch level. Response delay occurs both when a generating asset is not operating and receives a dispatch direction to begin operating and when an operating generating asset is dispatched to a different level. Shorter response delays improve the electric system’s ability to match the larger short-duration ramps that increase in frequency over the forecast period.

Figure 4-5 – Average response delay of dispatchable generation by scenario

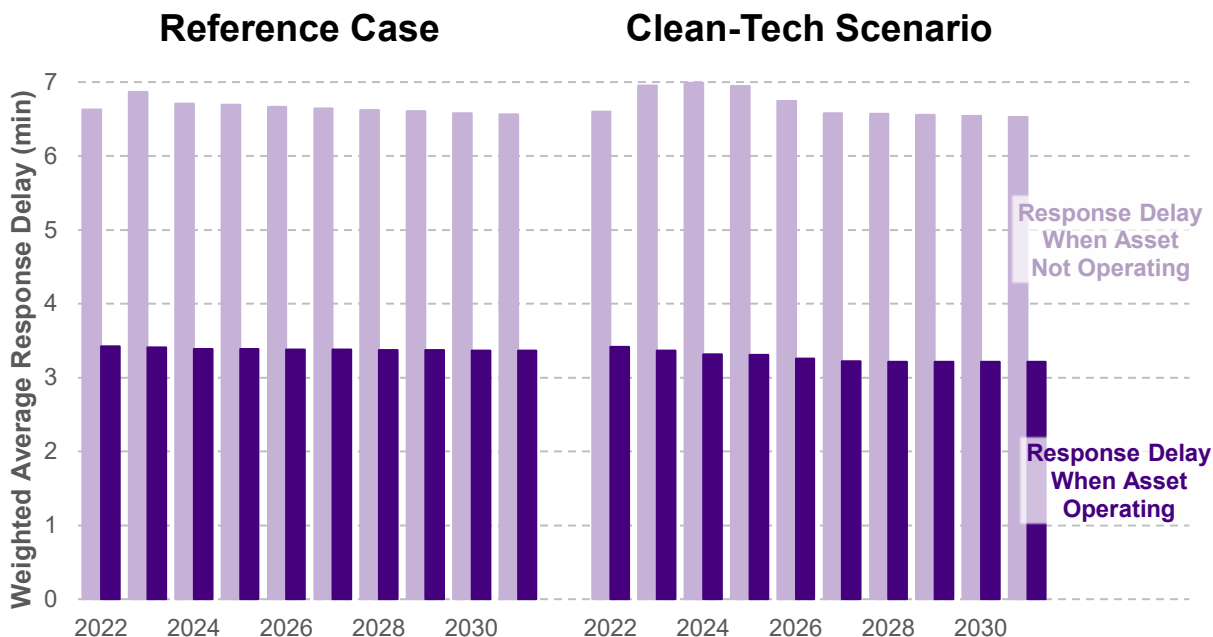


Figure 4-5 illustrates the average response delay of the dispatchable generation capacity included in the Reference Case and Clean-Tech Scenario, both when the generating asset is not operating and when it is operating. The average was calculated by weighting the response delay of each dispatchable generating asset by the capacity, in MW, of each asset. Response delays were based on recent observed characteristics by generation technology.

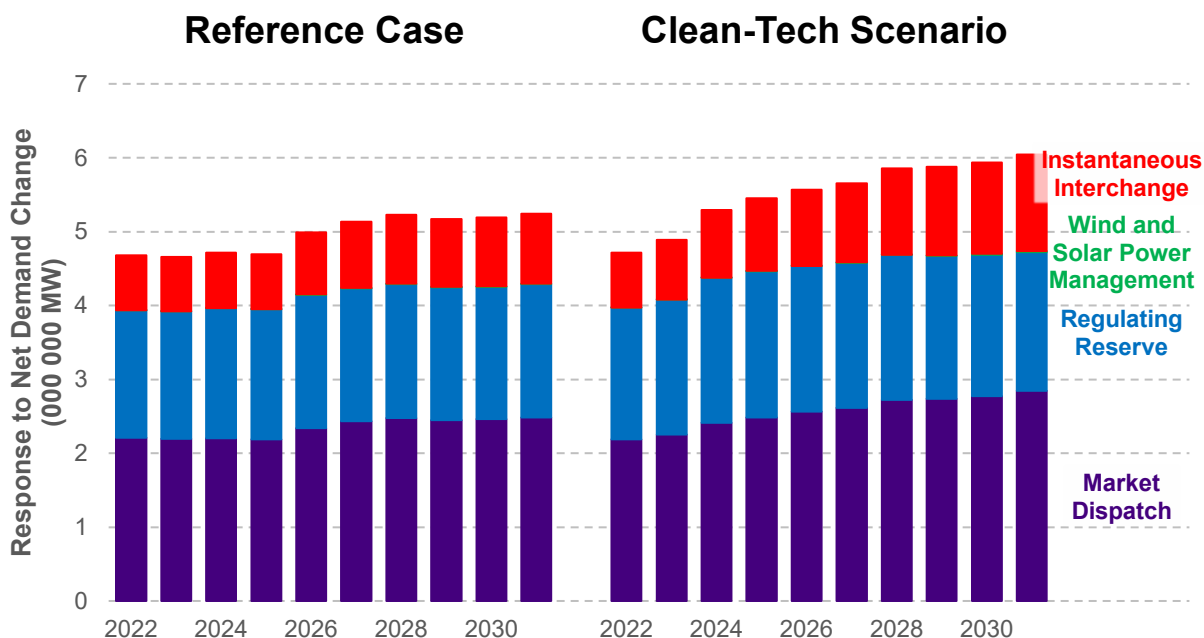
Average response delay does not materially change over the forecast period. Response delay shortens by about one to two per cent in the Reference Case and by about one to six per cent in the Clean-Tech Scenario, reflecting the different capacities of different generation technologies included in each scenario over the years of the forecast period. The stable response delay will allow the predictable dispatch of generation to respond to the larger net demand ramps that occur with greater frequency over the forecast period in both scenarios.

4.3 System flexibility responses to net demand change

As discussed in section 2.1 of this flexibility assessment, the AESO currently relies on three primary approaches to provide system flexibility: energy market dispatch, regulating reserve, and wind and solar power management.

In the dispatch simulation, a net demand change results in a system flexibility response through energy market dispatch, regulating reserve, or wind and solar power management. The dispatch simulation models both the intra-hour energy market dispatch up or down the merit order and regulating reserve ramping up or down via automatic generation control. The energy market dispatch up or down, in MW, and the regulating reserve ramping up or down, in MW, indicates the net demand change responded to through energy market dispatch and regulating reserve in the dispatch simulation. In actual system operation, regulating reserve also responds to frequency variation, which was not modelled in the dispatch simulation.

Figure 4-6 – System flexibility responses to net demand change, measured as cumulative absolute change in response over 10-minute intervals, by scenario



Wind and solar power forecasting enables the AESO to prepare for large wind and solar ramp-up events. In the dispatch simulation, when wind and solar ramp-up events are expected to result in fast and large net demand decreases, wind and solar power management is used to limit wind and solar generation ramping. Comparing the difference in wind and solar generation production, in MW, with and without the impact of wind and solar power management indicates the net demand change responded to through wind and solar power management.

Finally, when energy market dispatch, regulating reserve, and wind and solar power management do not entirely balance supply and demand in the dispatch simulation, the remaining imbalance results in instantaneous interchange with adjacent balancing authorities. The change in unscheduled interchange, in MW, indicates the net demand change responded to through instantaneous interchange with adjacent balancing authorities. In actual system operation, an imbalance in supply and demand remaining after energy market dispatch, regulating reserve, and wind and solar power management may also result in deviations in system frequency, which was not modelled in the dispatch simulation.

Figure 4-6 illustrates the quantities of energy market dispatch ramps, regulating reserve ramps, wind and solar power management impacts, and changes in instantaneous interchange that respond to net demand changes over the forecast period, for the Reference Case and Clean-Tech Scenario.

Over the forecast period in both scenarios, the increases in size and frequency of larger net demand ramps require increases in all the responses to system flexibility. The total response to system flexibility increases over the forecast period by about 12 per cent in the Reference Case and by about 28 per cent in the Clean-Tech Scenario. As well, the proportion of the response to system flexibility provided by each approach changes over the forecast period, as summarized in Table 4-7.

Table 4-7 – Proportion of system flexibility responses to net demand by scenario

Year	Through Market Dispatch	Through Regulating Reserve	Through Wind and Solar Power Management	Through Instantaneous Interchange
Reference Case				
2022	47%	37%	0.0%	16%
2031	47%	34%	0.1%	18%
Clean-Tech Scenario				
2022	46%	38%	0.0%	16%
2031	47%	31%	0.2%	22%

Note: Numbers may not add due to rounding

4.4 Forecast uncertainty

In Alberta’s energy market, real-time dispatch is performed by a system controller through the manual process of dispatching energy in the merit order. Continuous real-time system controller dispatch decisions maintain the balance between changing supply and changing demand. Every minute, system controllers face uncertainty as to what the next minute, 10 minutes, or other time interval of net demand will be and how to respond to net demand with dispatchable resources. The accuracy of real-time forecasts is not perfect, resulting in uncertainty or forecast error. Accurate forecasting is important to ensure the AESO has the information to manage the variability of net demand. This includes the accuracy of wind and solar generation forecasts.

In the dispatch simulation, the forecast wind generation reflected a constant ramp (sometimes referred to as persistent ramp): the wind generation ramp at the beginning of a 10-minute interval was extended to the end of the up-coming interval. The actual wind generation reflected the actual wind production modelled as described in section 3.2.4.

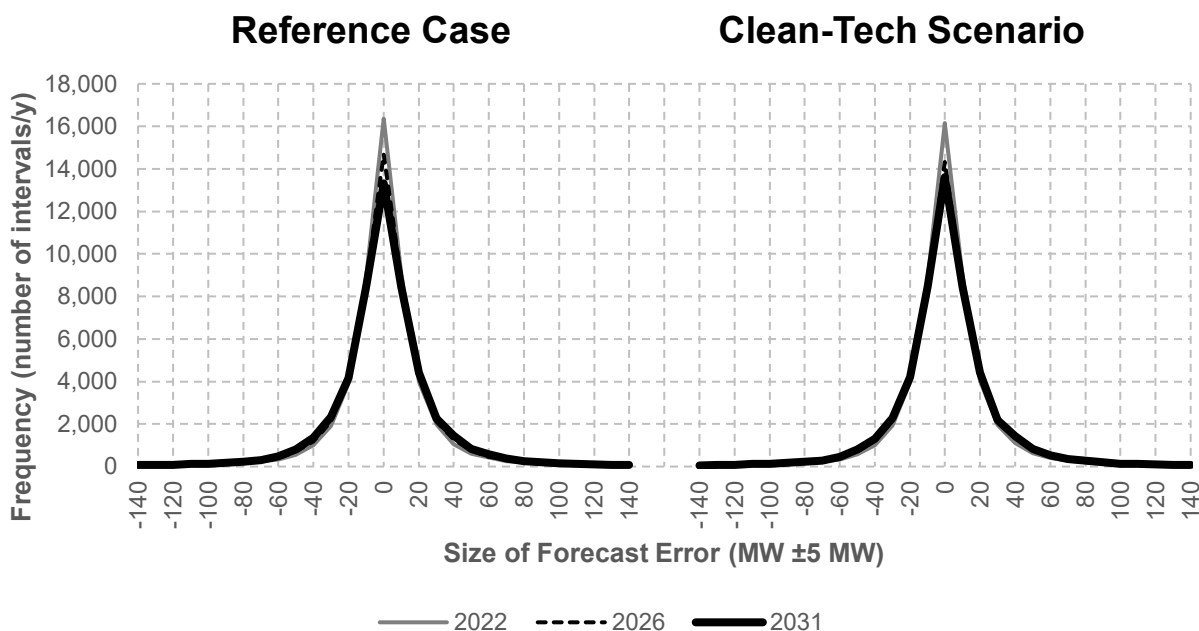
Figure 4-8 illustrates the distribution of the 10-minute-ahead wind generation constant-ramp forecast error over all hours in 2022, 2026, and 2031 for the Reference Case and Clean-Tech Scenario. The error at a given 10-minute interval is defined as the 10-minute-ahead constant-ramp forecast of wind generation minus the actual generation for that interval. The distribution of wind generation constant-ramp forecast error indicates increasing frequency of larger errors in both scenarios.

For wind generation constant-ramp forecast errors in both scenarios, the average size of large errors (of at least ± 50 MW) increased by about 11 to 13 per cent over the forecast period. Over the same time, the frequency of large errors increased from about 4,000 to over 5,000 10-minute intervals per year in each scenario. As well, the frequency of very large errors (of at least ± 200 MW) increased in both scenarios from about 300 10-minute intervals in 2022 to over 600 10-minute intervals in 2031. The increase in frequency of large wind generation constant-ramp forecast errors is attributed primarily to the increase in the capacity of wind generating assets, which is similar over the forecast period in both scenarios.

Solar generation forecast error was not assessed because of the limited actual solar production data available for solar generating assets.

The increases in size and frequency of large wind generation constant-ramp forecast error over 10-minute intervals will increase the challenges of responding to net demand changes through energy market dispatch.

Figure 4-8 – Distribution of 10-minute-ahead wind generation constant-ramp forecast error by scenario



4.5 Cumulative absolute dispatch ramp

As discussed in section 4.1, net demand variability is addressed through energy market dispatch of dispatchable generation up or down the merit order and through regulating reserve ramping of dispatchable generation up or down, via automatic generation control. Increasing net demand variability may result in dispatchable generation responding to larger dispatch ramps, more frequent ramping, or both.

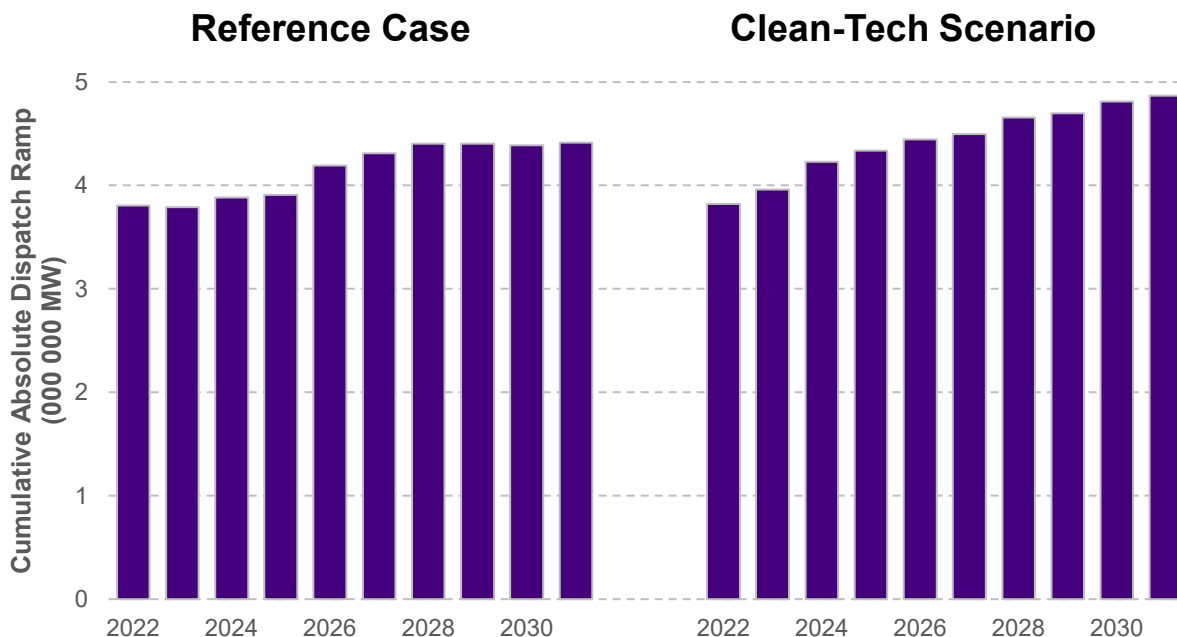
The combined effect of changes to ramp size and frequency may be assessed by examining cumulative absolute dispatch ramp, which provides the sum of all dispatchable generating asset ramps up and down on an absolute-value basis in aggregate. Each ramp up or down is measured in MW over an interval. The absolute value of each ramp up (positive) or down (negative) is then summed to calculate the cumulative absolute dispatch ramp in MW over all dispatchable generation. For example, over two intervals a 30 MW ramp up followed by a 30 MW ramp down represents a 60 MW cumulative absolute dispatch ramp.

Figure 4-9 illustrates the cumulative absolute dispatch ramp in aggregate over all 10-minute intervals in each year of the forecast period, in the Reference Case and Clean-Tech Scenario. Compared to 2022, cumulative absolute dispatch ramp of dispatchable generation increases over the forecast period by about 16 per cent in the Reference Case and by about 27 per cent in the Clean-Tech Scenario. Cumulative absolute dispatch ramp of dispatchable generation generally increases in proportion to increases in the variable generation capacity in the scenario.

Cumulative absolute dispatch ramp also tends to decrease as ramp rates of dispatchable generation become faster. When a fast-ramping dispatchable generating asset quickly responds to a net demand ramp, no additional assets need to be dispatched to address the imbalance that may remain at the end of an interval if a slow-ramping asset had responded.

Over the forecast period, dispatchable generation will be subject to increasing cumulative absolute dispatch ramp.

Figure 4-9 – Cumulative absolute dispatch ramp over 10-minute intervals by scenario



4.6 Asset on/off cycling

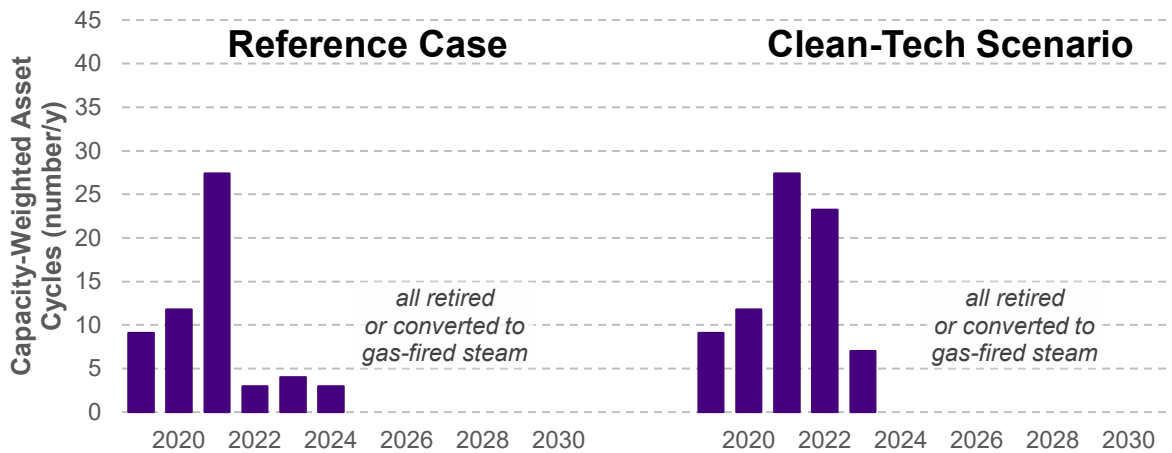
On/off cycling refers to a generating asset starting up from a non-operational state, operating at any level for any duration, and then shutting down to return to a non-operational state. Frequent on/off cycling typically increases the operational costs for generating assets that would otherwise operate continuously as baseload generation, such as coal-fired, combined-cycle, and gas-fired steam generating assets. Frequent on/off cycling may also reduce the expected life of baseload generating assets. Figure 4-10 presents the average on/off cycles for baseload generating assets weighted by maximum capability, over the forecast period for the Reference Case and Clean-Tech Scenario.

The number of on/off cycles for each generating asset was first counted from the simulation for each year from 2022 to 2031. For each technology type and year, the average of the on/off cycles of all generating assets was calculated, weighted by the maximum capability of each asset. All coal-fired, combined-cycle, and gas-fired steam generating assets were included in the calculation, except for assets within the City of Medicine Hat.

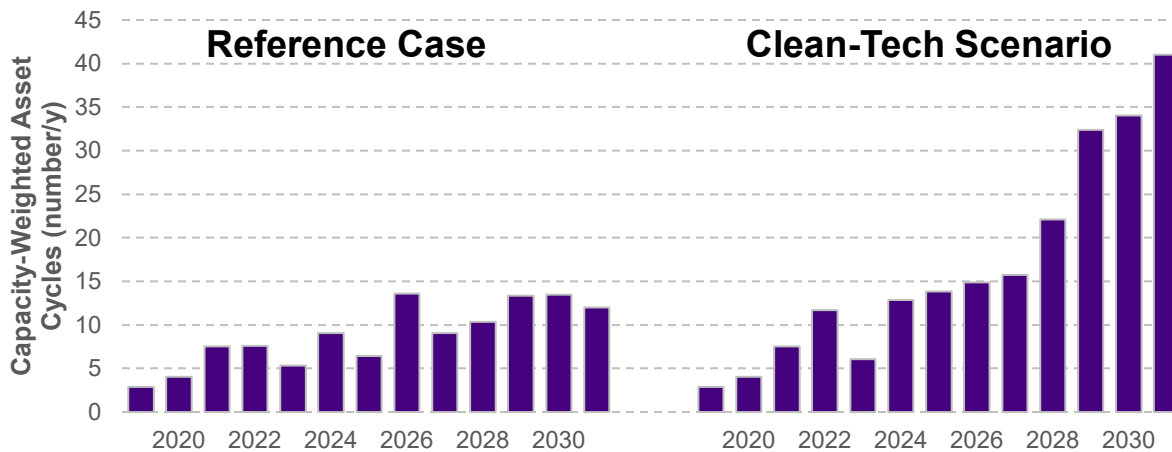
The number of on/off cycles experienced by an individual generating asset in the simulation is primarily affected by the generating asset offers. Over the forecast period in the Reference Case, on/off cycling remains relatively constant for combined cycle generating assets and increases for gas-fired steam generating assets. In contrast, over the forecast period in the Clean-Tech Scenario, on/off cycling increases for combined cycle generating assets and decreases during the middle years of the forecast period for gas-fired steam generating assets. These changes are attributed to interactions that affect offers in the markets differently for different generation technologies, including the significantly larger combined cycle capacity and the significantly smaller gas-fired steam capacity in the later years of the Clean-Tech Scenario compared to the Reference Case.

Figure 4-10 – Average number of on/off cycles per generating asset by technology by scenario

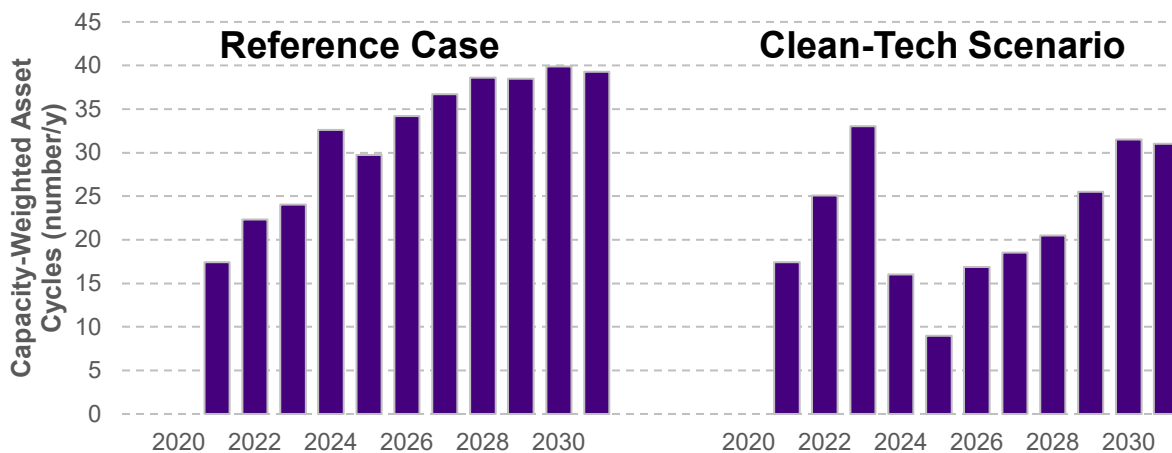
Coal-Fired Generating Assets



Combined Cycle Generating Assets



Gas-Fired Steam Generating Assets



Note: Cycles for 2019-2021 reflect actual amounts; cycles for 2022-2031 reflect forecast amounts

4.7 Supply cushion

Supply cushion represents the additional capacity in the merit order that remains available for dispatch after load is served. Supply cushion may be calculated differently for different purposes; in this flexibility assessment supply cushion is calculated as available generation capacity, including variable generation and operating reserve, plus available inertia import capacity, minus load demand. Large supply cushion values indicate greater reliability because more capacity remains available to respond to forced outages or unexpected increases in demand. When supply cushion falls to zero, all available capacity in the energy market has been dispatched to run, and system controllers may be required to take emergency action to ensure system stability.

In Figure 4-11, the horizontal axis shows the amount of supply cushion, in MW, in every 1-hour interval during the year, with supply cushion amounts aggregated in incremental 100 MW bins. The vertical axis shows the number of 1-hour intervals in the year that had supply cushion of the amount indicated on the horizontal axis. Supply cushion is shown for 2022, 2026, and 2031 for both the Reference Case and the Clean-Tech Scenario.

The frequency distribution illustrates that supply cushion is greater in many hours in later years compared to earlier years of the forecast period in both the Reference Case and the Clean-Tech Scenario, reflecting the growth in generation capacity on the electric system over those years. To focus on the frequency of hours with low supply cushion, Figure 4-11 does not include hours with supply cushion greater than 4,000 MW, which in the dispatch simulations are:

- In the **Reference Case**, about 2,200 hours in 2022 and about 5,400 hours in 2031.
- In the **Clean-Tech Scenario**, about 2,000 hours in 2022 and about 3,100 hours in 2031.

Although larger supply cushion is more frequent in later years in both scenarios, supply cushion is consistently less in the Clean-Tech Scenario compared to the Reference Case. For example, in the dispatch simulations, average supply cushion is:

- In **2022**, about 3,400 MW in both the Reference Case and Clean-Tech Scenario.
- In **2026**, about 4,000 MW in the Reference Case and about 3,300 MW in the Clean-Tech Scenario.
- In **2031**, about 4,400 MW in the Reference Case and about 3,600 MW in the Clean-Tech Scenario.

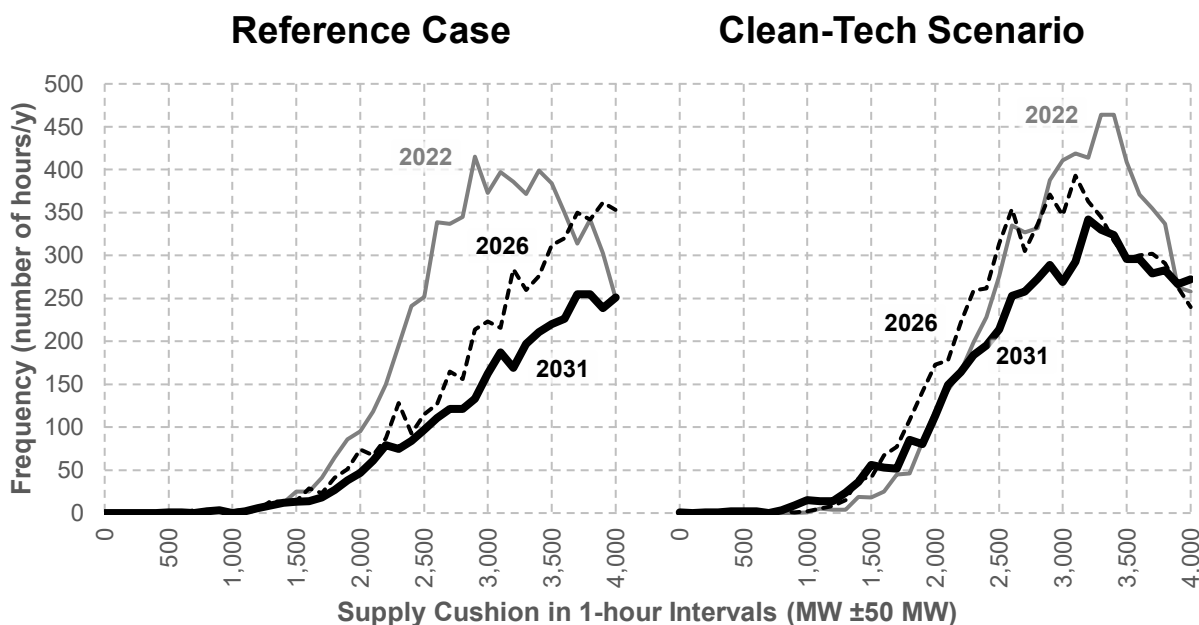
The comparatively lower supply cushion in the Clean-Tech Scenario is attributed to the greater proportion of generation capacity from renewable resources in the Clean-Tech Scenario, which gives rise to more frequent hours with low production from renewable resources.

Supply cushion is also more frequently critically low in later years of the Clean-Tech Scenario compared to the Reference Case. For example, in the dispatch simulations, supply cushion:

- Does not fall below 500 MW in the Reference Case in any hours from 2026 to 2031.
- Starts falling below 500 MW in the Clean-Tech Scenario for 5 hours in 2028 and increases to falling below 500 MW for 13 hours in 2031.

The increasing frequency of hours with very low supply cushion in the Clean-Tech Scenario indicates increasing risk that system controllers may be required to take emergency action to ensure system stability if supply cushion falls to zero due to forced outages or unexpected increases in demand.

Figure 4-11 – Available generation capacity (including operating reserve plus available intertie import capacity, minus load demand) in 1-hour intervals by scenario



4.8 Supply surplus

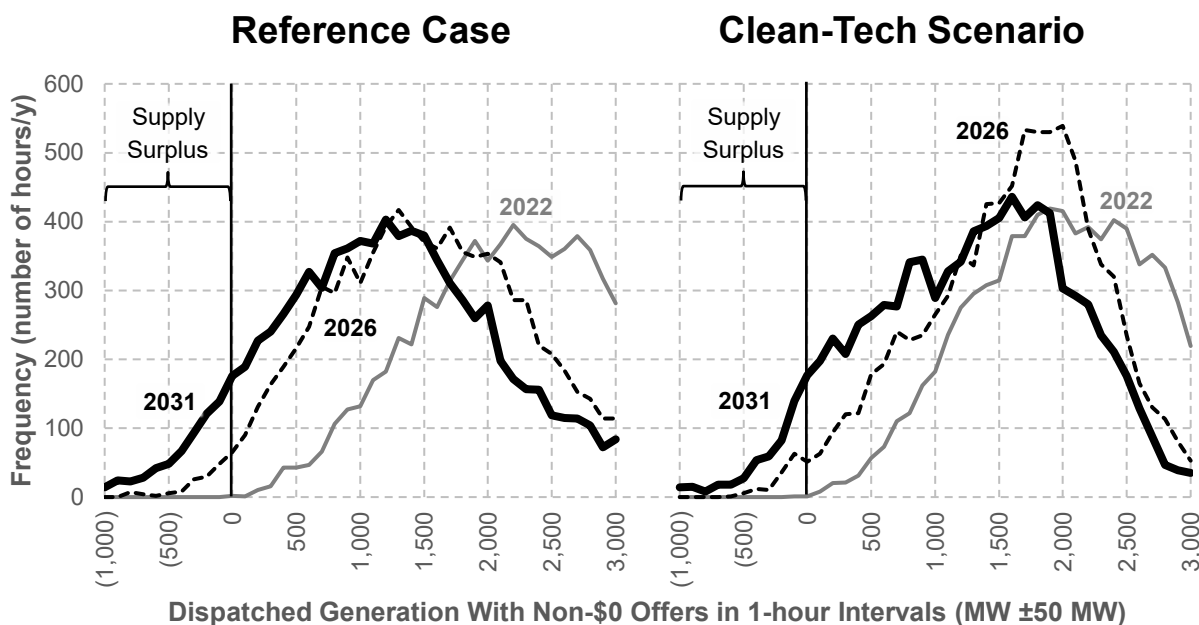
Supply surplus occurs when the supply of energy offered to the market at zero dollars per megawatt-hour (\$0/MWh) exceeds system demand. In supply surplus hours, all dispatched generation and scheduled imports are priced at \$0/MWh. Supply surplus primarily occurs in hours with high supply from variable generation and scheduled imports, both of which are generally offered at \$0/MWh.

Figure 4-12 illustrates supply surplus as the frequency distribution of dispatched generation capacity that is offered above \$0/MWh in the dispatch simulations for 2022, 2026, and 2031 in the Reference Case and Clean-Tech Scenario. The horizontal axis shows the amount of dispatched generation capacity, in MW, that is offered above \$0/MWh in every 1-hour interval during the year, with dispatched capacity aggregated in incremental 100 MW bins. Negative capacity amounts indicate the generation capacity offered at \$0/MWh that is in excess of system demand. The vertical axis shows the number of intervals in the year that had dispatched capacity priced above \$0/MWh in the amount of capacity indicated on the horizontal axis.

The frequency distribution illustrates that supply surplus occurs in more hours in later years compared to earlier years of the forecast period in both the Reference Case and the Clean-Tech Scenario. For example, in the dispatch simulations:

- In **2022**, one supply surplus hour occurs in the Reference Case and none in the Clean-Tech Scenario.
- In **2026**, about 160 supply surplus hours occur in both the Reference Case and Clean-Tech Scenario.
- In **2031**, about 700 supply surplus hours occur in the Reference Case and about 600 in the Clean-Tech Scenario.

Figure 4-12 – Dispatched generation capacity that is offered above \$0/MWh in 1-hour intervals by scenario



The average amount by which generation capacity offered at \$0/MWh exceeds system demand in hours when supply surplus occurs is somewhat higher in the Reference Case than in the Clean-Tech Scenario in the first half of the forecast period, reflecting greater cogeneration and other natural gas-fired generation capacity during those years. This trend reverses in the later years of the forecast period, and the average supply surplus increases to about 420 MW in the Clean-Tech Scenario (averaged over the 600 hours of supply surplus in the Clean-Tech Scenario in 2031) compared to 390 MW in the Reference Case (averaged over the 700 hours of supply surplus in the Reference Case in 2031), reflecting the greater amounts of wind and solar generation capacity in the Clean-Tech Scenario.

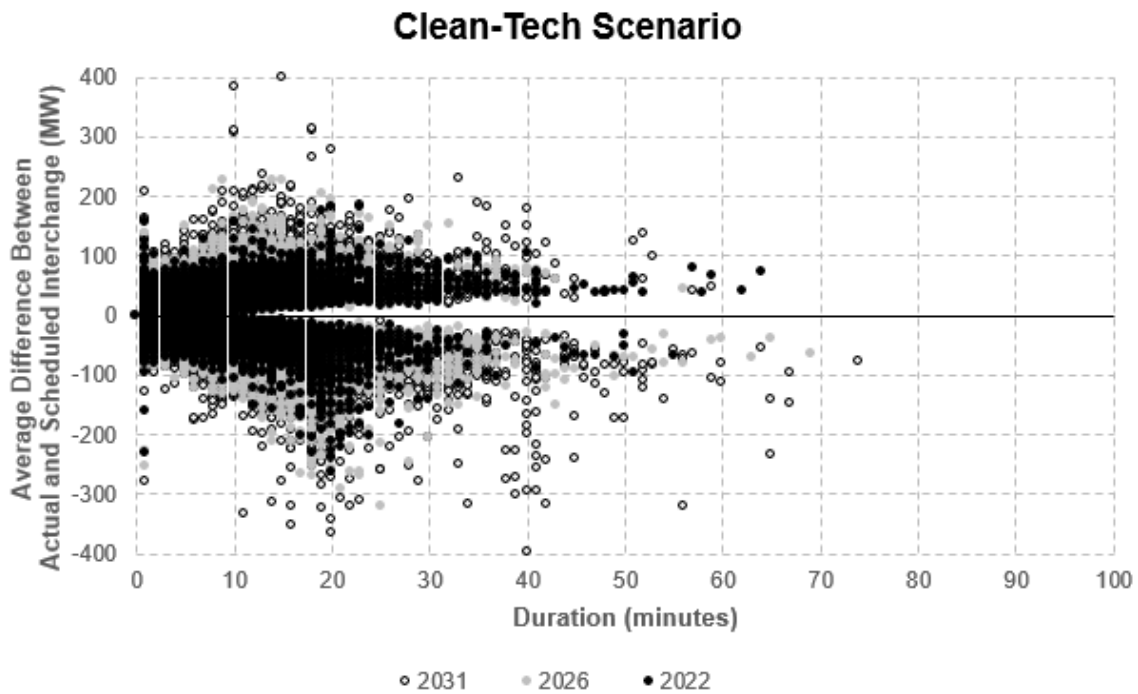
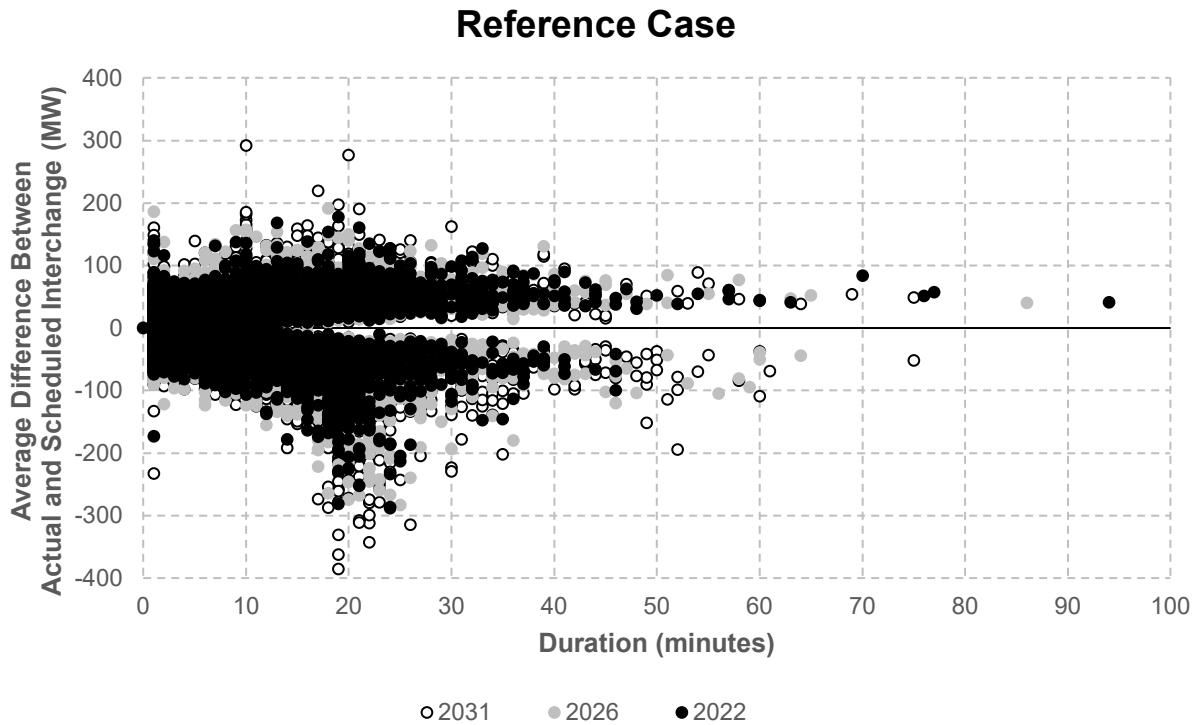
The increase in supply surplus hours indicates an increasing likelihood that system controllers may be required to take out-of-market actions to balance supply and demand, such as halting imports, rescheduling exports, or curtailing or cutting in-merit generation.

4.9 Simulated area control error

As discussed in section 2.1 of this system flexibility assessment, under normal system operation the approaches of energy market dispatch, regulating reserve, and wind and solar power management do not entirely balance supply and demand in real-time. Any remaining load-interchange-generation imbalances result in instantaneous interchange with adjacent balancing authorities or in deviations in system frequency, both of which are managed in accordance with Alberta reliability standards.

Interchange used to maintain system balance can be measured as the difference between actual interchange and scheduled interchange over an interval. The difference between actual interchange and scheduled interchange is the area control error, which also takes into account the effects of frequency bias, time error, and a correction for metering error.

Figure 4-13 – Duration and size of simulated area control errors by scenario



The dispatch simulation did not model the effects of frequency bias, time error, and metering error, and as a result the simulated area control error includes only the difference between actual interchange and scheduled interchange. The difference reflects the use of instantaneous interchange to balance the Alberta electric system, in addition to the system flexibility provided by generating assets in the province. The use of the interchange is governed by Alberta reliability standards and through the Western Electricity Coordinating Council, of which the AESO is a member. The reliability standards require the AESO to monitor and manage instantaneous interchange within specified limits as part of obligations of all members of WECC to effectively and efficiently mitigate risks to the reliability and security of the Western Interconnection.

Figure 4-13 illustrates the duration and size of simulated area control error in 2022, 2026, and 2031 for the Reference Case and Clean-Tech Scenario. The horizontal axis is the duration of the simulated area control error, measured as the time, in minutes, from when the actual interchange becomes larger (or smaller) than the scheduled interchange, to when it returns to equal the scheduled interchange. The vertical axis is the average difference between actual interchange and scheduled interchange, in MW, over the duration on the horizontal axis. The average difference may be positive (actual interchange greater than scheduled interchange) or negative (actual interchange less than scheduled interchange).

Figure 4-13 illustrates that simulated area control error appears with longer durations and greater average differences in the 2026 and 2031 simulations in both the Reference Case and Clean-Tech Scenario. In the dispatch simulations, simulated area control errors can last for extended durations due to continued variability of load and variable generation. The variability remains above (or below) the levels used for energy market dispatch for multiple dispatch intervals, with the variability beyond that which can be addressed through regulating reserve. The simulated area control error data points also represent the average differences between actual and scheduled interchange over durations in which the interchange is continuously positive or continuously negative. Within those durations, the instantaneous difference between actual and scheduled interchange may be near-zero for one or more minutes.

The average differences become greater (primarily negative) at about 15 to 25 minutes duration in 2026 and 2031. Those greater differences are attributed to the solar generation capacity included in the simulations in later years, where intermittent cloud cover may cause short-term variability that is responded to in the subsequent 10-minute dispatch interval through energy market dispatch or operating reserve. As a solar generation forecast is not included in the dispatch simulation, solar variability is likely to result in instantaneous interchange over a 10-minute dispatch interval.

The simulated area control error durations and differences are expected to remain within acceptable performance ranges over the forecast period. However, the increase in simulated area control error durations and differences indicates that the system flexibility responses provided through energy market dispatch and regulating reserve are not fully addressing the expected increase in net demand variability.

4.10 Indicative market impact of responding to net demand variability

As discussed in section 2.1 of this report, system flexibility refers to the ability of the electric system to adapt to dynamic and changing conditions, including those related to net demand variability. If changes in net demand could be predicted with certainty over an interval, energy market dispatch could be used to precisely respond to those changes. However, real-time dispatch usually differs from predictions, and net demand variability may also occur within an interval.

The dispatch simulation allowed these two conditions—theoretical perfect dispatch and simulated real-time dispatch—to be observed. A theoretical perfect energy market dispatch at the beginning of a 10-minute interval would result in generating asset production that exactly balanced net demand at the end of the up-coming interval.

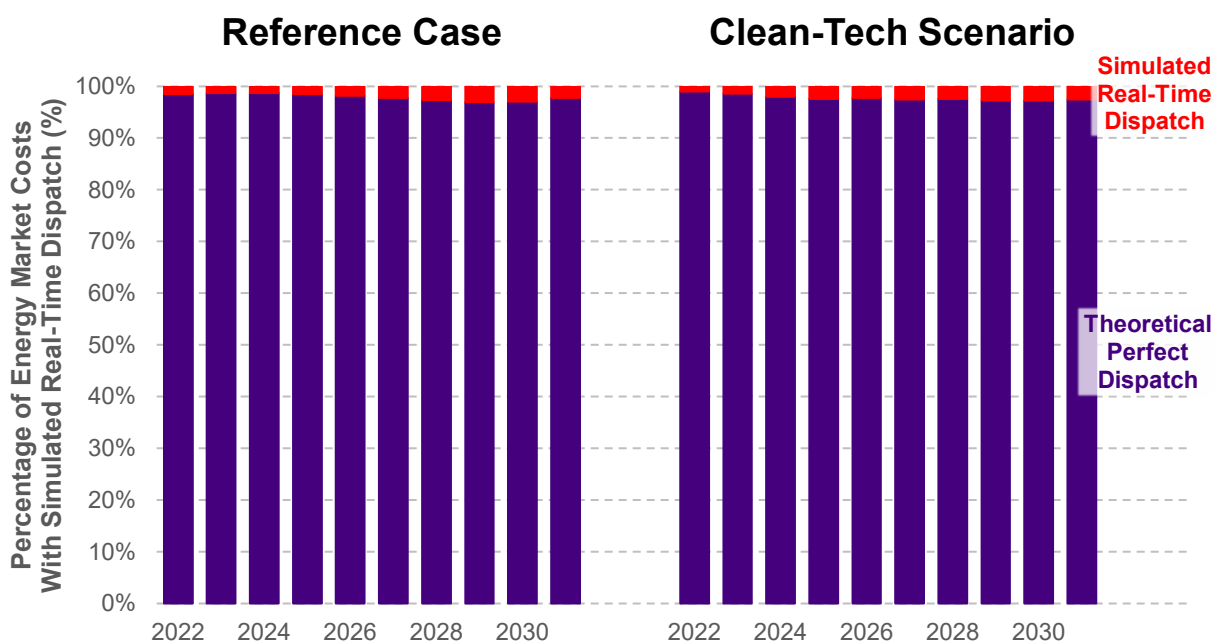
Simulated real-time dispatch reflects more realistic system operation, recognizing the effects of generating asset characteristics, forecast error, and real-time conditions. The theoretical perfect and simulated real-time dispatch levels were each multiplied by pool price in each interval and then summed over the year. The difference between these two sums provides an indication of the market impact of responding to changes in net demand that cannot be perfectly predicted.

Figure 4-14 illustrates the difference between the energy market costs estimated with theoretical perfect dispatch and with simulated real-time dispatch in each year of the forecast period, in the Reference Case and Clean-Tech Scenario. Energy market costs with theoretical perfect dispatch are 1.0 per cent to 3.0 per cent lower than with simulated real-time dispatch, in all years over the forecast period in both scenarios. On average, energy market costs with theoretical perfect dispatch are about 2.0 per cent lower in the Reference Case, and about 2.2 per cent lower in the Clean-Tech Scenario, than with simulated real-time dispatch. The incremental cost estimated with simulated real-time dispatch increases over the forecast period in both scenarios, on average by 0.2 per cent of costs estimated with theoretical perfect dispatch per year.

The AESO acknowledges that theoretical perfect dispatch will never be achievable due to forecast error, response variability of dispatchable generation, and other factors. However, comparing the energy market costs estimated with theoretical perfect dispatch and with simulated real-time dispatch provides an indication of the magnitude and rate of change of the cost impact of net demand variability on the energy market.

The AESO has included this market impact information as indicative of the trend of cost differences between theoretical perfect dispatch and simulated real-time dispatch. The cost differences include significant uncertainty resulting from the simulation assumptions discussed in section 3.3.4. The AESO expects to continue examining the market impact of responding to net demand variability in future system flexibility assessments.

Figure 4-14 – Indicative market impact of responding to net demand change by scenario



5 Operational simulation results

As discussed previously in section 3.1, the installed capacities of different generation technologies in Alberta are expected to change during the next ten years, with large coal-fired capacity decreasing, natural gas-fired capacity increasing, and wind, solar, and energy storage capacity all increasing as well. This transition is shifting the operational and performance characteristics of the electric system and may present challenges to maintaining system reliability. System inertia, primary frequency response, and system fault response characteristics will be affected by the changes to generation technologies and capacities.

5.1 System inertia

System inertia refers to the kinetic energy stored in rotating masses of generators and motors that are synchronously connected to the electric system. Inertia response automatically releases that kinetic energy and contributes to the stability and reliability of the system by slowing the rate of change of frequency in the initial seconds following a sudden loss of supply or demand. The amount of inertia depends on the number and size of generators and motors synchronized to the system. Inverter-based resources, including variable generation, most energy storage assets, and other resources that use grid-following inverters, are not synchronous generators and typically do not provide inertia response.

A lower level of system inertia holds less kinetic energy and allows frequency to change more rapidly. This in turn reduces the time in which primary frequency response can act to arrest the decline in frequency and keep it above under-frequency load shed thresholds.

Figure 5-1 illustrates the rate of change of frequency expected to occur after a sudden loss of imports or a sudden loss of supply under islanded conditions, at different levels of system inertia available from online synchronous generators, in gigavolt-ampere-seconds (GVA·s). The horizontal axis shows the amount of import or supply capacity, in MW, suddenly lost on the system.

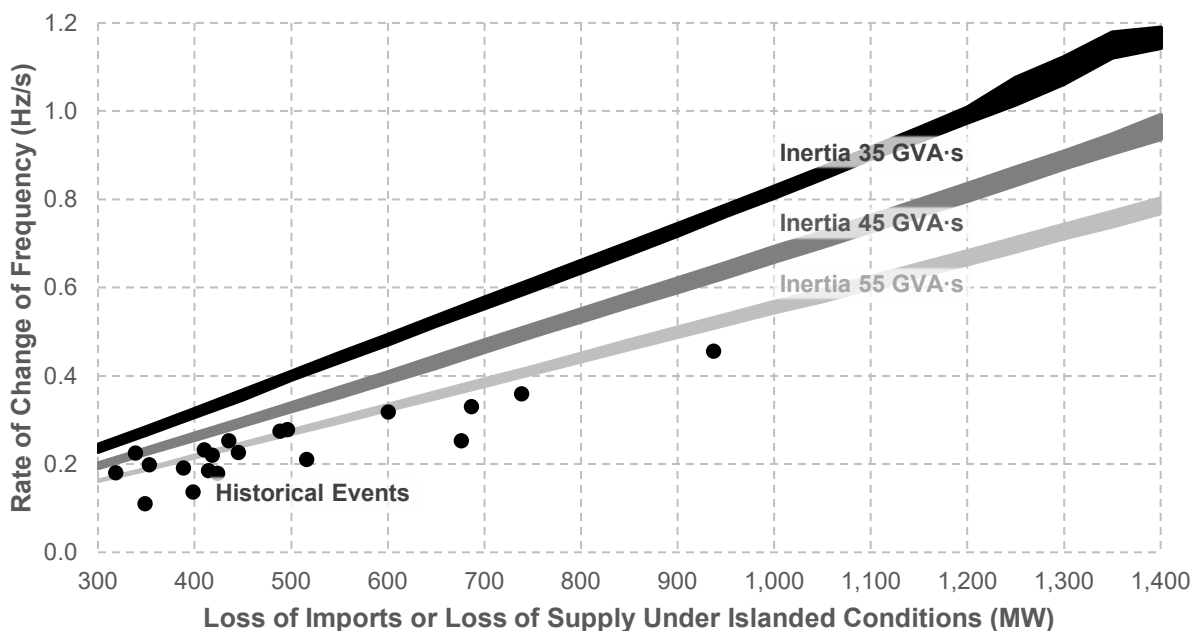
Under normal conditions, the impact of loss of supply is significantly reduced because Alberta is synchronously connected to the transmission systems that comprise the Western Interconnection. The system inertia simulations accordingly examined the impact of loss of imports, which results in an instantaneous transition from synchronously connected conditions to islanded conditions. Loss of imports when synchronously interconnected has the same impact as loss of the same amount of supply under islanded conditions, although the amount of imports could exceed the capacity of any individual generating asset in Alberta and could potentially have a larger impact than loss of supply.

In Figure 5-1, the vertical axis shows the rate of change of frequency, in hertz per second (Hz/s), in the operational simulations in the first 0.5 second after the loss of capacity. The different levels of system inertia included in the simulations reflect a range of typical levels from online synchronous generators experienced today and likely to occur during the next ten years. The simulations did not include the comparatively small levels of inertia provided by load and, as a result, provide somewhat higher rate of change of frequency results than would be experienced in real-time operations.

The rate of change of frequency varies from a decline of about 0.2 Hz/s when 300 MW of capacity is suddenly lost to a decline from about 0.8 to 1.2 Hz/s when 1,400 MW of capacity is lost. Figure 5-1 includes observations from historical events from 2013 to 2021 involving the sudden loss of imports or the sudden loss of supply under islanded conditions, which reasonably align with the simulation results.

As discussed in section 3.3.4, the examination of system inertia, primary frequency response, and system fault response assumed operating conditions that represented different combinations of load, import, inertia, and generator response that are reasonably expected in the Reference Case and Clean-Tech Scenario over the forecast period.

Figure 5-1 – Rate of change of frequency after loss of imports or loss of supply under islanded conditions, at different levels of system inertia from synchronous generators



The operational studies did not examine all operating conditions that occur in the Reference Case and Clean-Tech Scenario. However, the inertia characteristics of generators are stable values, and the AESO extended the market and dispatch simulations discussed in section 4 to assess the frequency distribution of system inertia from online generators.

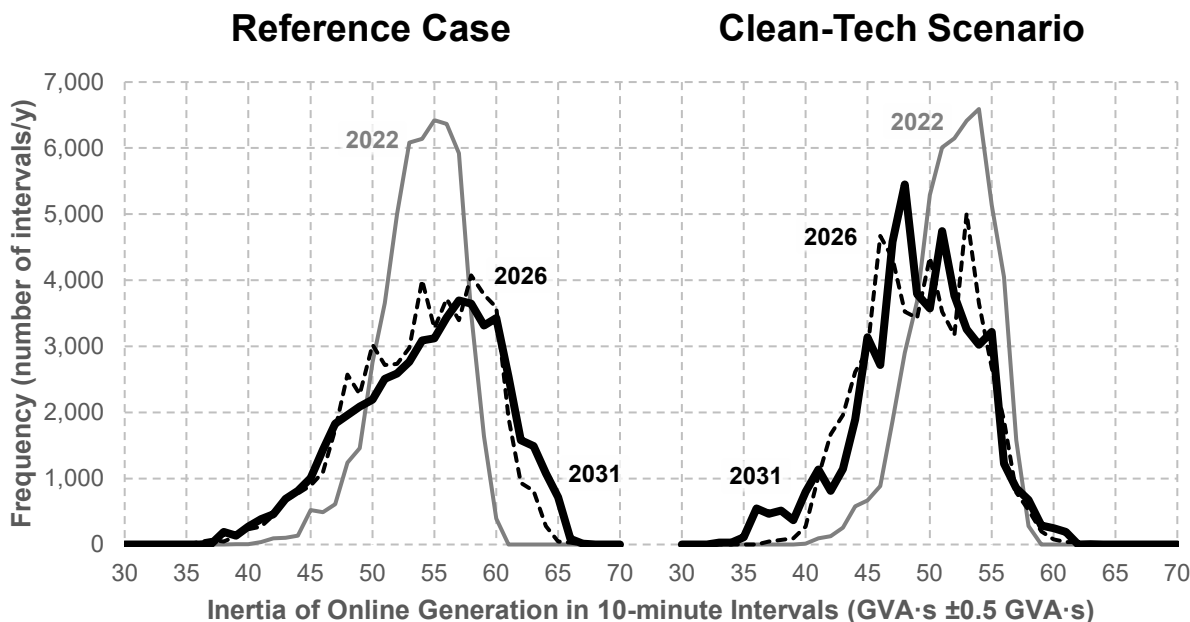
Figure 5-2 illustrates the frequency distribution of system inertia from online synchronous generators in the dispatch simulations for 2022, 2026, and 2031 in the Reference Case and Clean-Tech Scenario from the *AESO 2021 Long-term Outlook*. The horizontal axis shows the amount of system inertia from online generators, in GVA·s, in every 10-minute interval during the year. System inertia amounts are aggregated in incremental 1 GVA·s bins. The vertical axis shows the number of intervals in the year that had system inertia of the amount indicated on the horizontal axis.

The frequency distribution illustrates that lower levels of system inertia from online generators occur more frequently in later years in both the Reference Case and the Clean-Tech Scenario. For example, the cumulative occurrence of low system inertia (up to 40 GVA·s) in the dispatch simulation is:

- Fewer than 20 10-minute intervals in 2022 in both the Reference Case and Clean-Tech Scenario.
- About 500 intervals in 2031 in the Reference Case.
- About 2,500 intervals in 2031 in the Clean-Tech Scenario.

The more frequent lower levels of system inertia in later years in the Clean-Tech Scenario reflects the greater amounts of wind and solar generation capacity in the Clean-Tech Scenario. The AESO manages the risk of low system frequency conditions and consequent triggering of under-frequency load shed through mitigating low system inertia conditions, through ensuring effective primary frequency response from generation, by managing loss of import and loss of supply contingencies, and by procuring services such as load shed and fast frequency response services.

Figure 5-2 – Inertia of online synchronous generation in 10-minute intervals by scenario



These approaches are complementary to each other and together allow system frequency to be maintained in accordance with Alberta reliability standards.

The AESO will continue to monitor system inertia trends and implement mitigation measures as appropriate to ensure sufficient system inertia as levels of variable generation increase on the system.

5.2 Primary frequency response

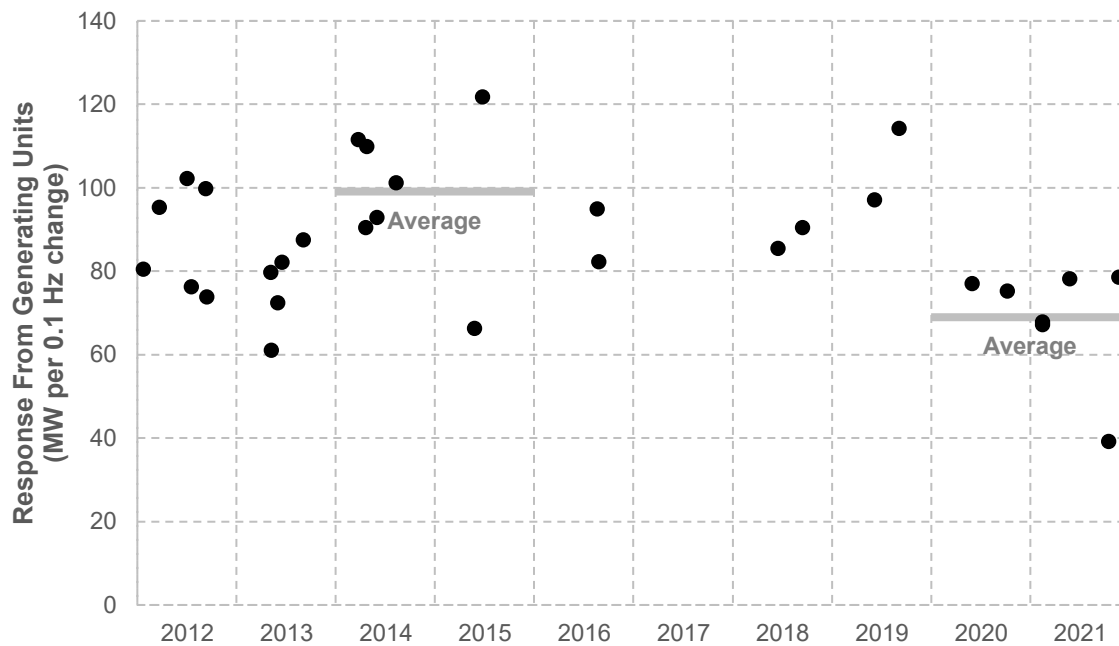
Primary frequency response:

- Refers to automatic changes in real power production or consumption from generators, loads, or fast frequency response service resources.
- Reacts rapidly and autonomously to arrest and stabilize locally detected changes in frequency.
- Begins when a frequency change beyond a specified level is detected, typically in the initial seconds following a sudden loss of supply or demand (at the same time as inertia response) and may continue to contribute to frequency stabilization for up to a minute or more.

The speed and amount of primary frequency response varies between generating unit technologies, loads, and fast frequency response service resources, as well as due to the capacity currently not dispatched for an online generating unit and the operating conditions that exist when the loss of supply or demand occurs. Primary frequency response acts to keep frequency above under-frequency load shed thresholds until the system operator’s centralized energy management system can act to restore system frequency.

Figure 5-3 illustrates the primary frequency response (that is, the increase in real power production) from generating units dispatched at the time of a frequency drop due to a loss of imports or loss of supply in Alberta under islanded conditions. The horizontal axis shows the date of the frequency event, and the vertical axis shows the amount of primary frequency response, in megawatts per 0.1 hertz change in frequency (MW per 0.1 Hz change).

Figure 5-3 – Primary frequency response from synchronous generating units during historical frequency events



The average amount of primary frequency response from generating units during frequency events has declined from about 99 MW per 0.1 Hz change in 2014-2015 (averaged over seven events) to about 69 MW per 0.1 Hz change in 2020-2021 (also averaged over seven events).

As mentioned previously, the speed and amount of primary frequency response depends on the characteristics of the generating units dispatched at the time of the frequency event, their undischarged capacity, and the operating conditions that exist, all of which vary over time. For example, the *AESO 2021 Annual Market Statistics* report observed:

- Changes in installed capacity of different generation technologies, including retirements and conversions of coal-fired generation capacity, increasing simple cycle generation capacity, and increasing penetration of renewable generation capacity.
- Decreases in supply cushion, which is the additional energy in the merit order that remains available for dispatch after load is served, especially in the summer months.
- Changes in the availability, utilization, and offer practices of different generation technologies and increases to summer load, behind-the-fence load, and northeast load, all of which contribute to changes in operating conditions.

These changes impact the characteristics of the generating units dispatched at the time of the frequency event, their undischarged capacity, and the operating conditions that exist. The AESO is continuing to investigate the underlying causes of the observed decline in primary frequency response and will provide additional information to stakeholders as these investigations progress.

As with system inertia, the AESO manages the risk of low system frequency conditions and consequent triggering of under-frequency load shed through mitigating low system inertia conditions, through ensuring effective primary frequency response from generation, by managing loss of import and loss of supply contingencies, and by procuring services such as load shed and fast frequency response services.

These approaches are complementary to each other and together allow system frequency to be maintained in accordance with Alberta reliability standards.

The AESO is evaluating and, where appropriate, implementing mitigation measures to maintain primary frequency response at levels sufficient to respond to low system frequency conditions as variable generation increases on the system.

Measures being implemented include:

- Collaboration with generating facility owners to improve primary frequency response from their units.
- Improvement to the situational awareness of expected primary frequency response in the system control centre.
- Modifications to the AESO's modelling and operational assumptions to reflect recently observed primary frequency response levels.

Additional measures being considered include:

- Clarification of expectations for primary frequency response from generation assets.
- Engagement with stakeholders on modifications to connection requirements for generating units.
- Engagement with stakeholders on modifications to ISO rules to improve standards and performance metrics for primary frequency response.

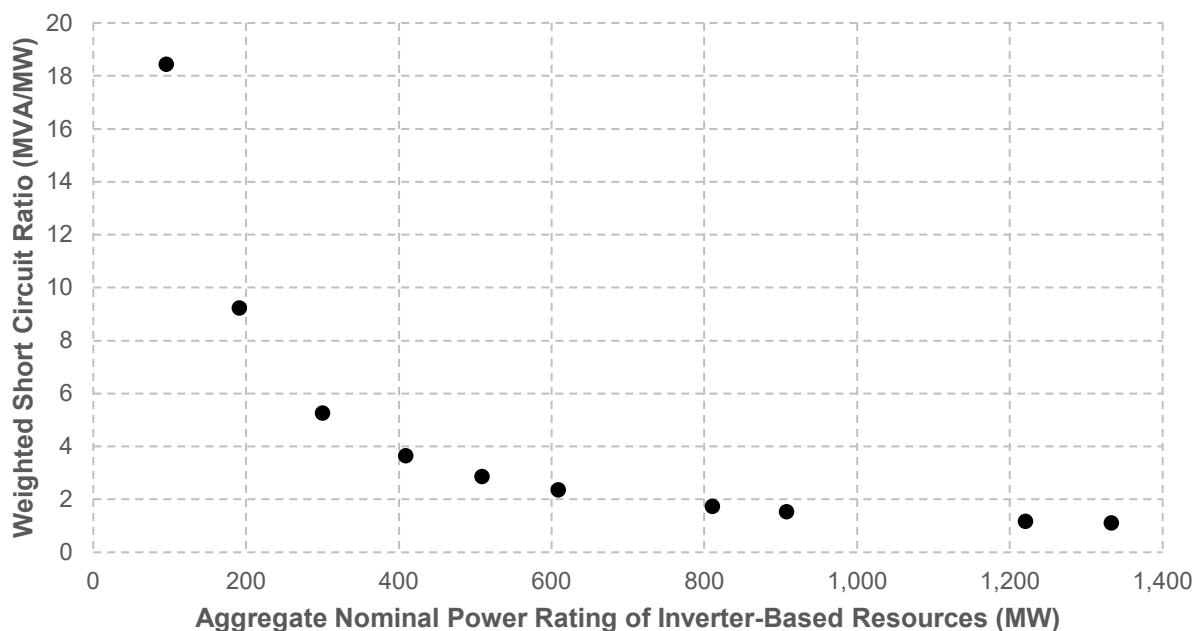
The AESO will update stakeholders with further information on the conclusions of its continuing investigation of recent primary frequency response trends, and as additional mitigation measures are identified for implementation.

5.3 System fault response

A fault on the electric system refers generally to any abnormal condition of the system that involves electrical failure of equipment such as transformers, generators, and conductors. When a fault occurs, voltage and current values deviate from their normal ranges, the fault is detected, and protection equipment operates to limit damage and loss of service due to the fault. A system with strong fault response is able to maintain stable voltage and reliably detect and isolate faults at a particular location following a disturbance such as a lightning strike, adverse weather conditions, and equipment failure. System fault response is indicated by the short circuit capacity on an electric system during a power flow excursion or system disturbance. A high short circuit level indicates the electric system is better able to operate in a stable and reliable manner in response to a disturbance.

Traditional generation sources such as coal-fired, natural gas-fired, and hydro generation generally have strong fault response characteristics when connected to the transmission system. In contrast, generators connected to the transmission system using grid-following inverters have weaker fault response characteristics, which lowers the system's ability to detect and respond to faults. Grid-following inverters are currently the dominant technology used to connect variable generation in Alberta, which are collectively referred to as inverter-based resources.

Figure 5-4 – Weighted short circuit ratios as grid-following inverter-based resources connect in close electrical proximity



The control and regulation functions of inverter-based resources that use grid-following inverters predominantly rely on the magnitude and angle of the system voltage at the point where the inverter-based resource connects to the electric system. The fault response performance of the electric system reflects the relative impedances between grid-following inverter-based resources and conventional synchronous generation sources.

In an area where the electric system has weak fault response, a grid-following inverter-based resource is at risk of poor fault response performance, instability, or both, with the risk increasing if multiple grid-following inverter-based resources are located in close electrical proximity and are electrically distant from other generation sources that have strong fault response performance.

System fault response can be evaluated using a metric known as short circuit ratio, which is defined as the short circuit level at the point of a generator's connection to the electric system divided by the generator's nominal power rating. For a group of nearby inverter-based resources, short circuit level is affected by nearby connections of other generators. In such a group, the short circuit ratio is weighted to better reflect the impact of nearby generators in the group.

Figure 5-4 illustrates the weighted short circuit ratios as grid-following inverter-based resources are connected in a group in close electrical proximity in southeast Alberta. The horizontal axis shows the aggregate nominal power rating of a group of inverter-based resources that all use grid-following inverters, and the vertical axis shows the weighted short circuit ratio, in megavolt-amperes per megawatt (MVA/MW), for the group. Higher weighted short circuit ratios indicate a stronger fault response.

For the grid-following inverter-based resources in southeast Alberta, the weighted short circuit ratio declines as the aggregate nominal power rating of the inverter-based resources increases, as illustrated in Figure 5-4. Similar declines would generally occur for other groups of grid-following inverter-based resources, with variation reflecting the short circuit levels of the specific inverter-based resources and the characteristics of the electric system in the area.

Where a group of inverter-based resources results in very low fault response, indicated by a weighted short circuit ratio of about 3 MVA/MW or lower, detailed analysis is required to ensure voltage stability and reliability will be maintained following a system disturbance. To date, the AESO has identified four groups of grid-following inverter-based resources with very low fault response and is completing more detailed analysis of those groups and the electric systems in the areas where they are located.

Strong fault response indicates the transmission system is able to quickly dampen voltage oscillations after a disturbance. Weak fault response may indicate potential system performance issues that may cause undesirable instability or generator trip during normal or abnormal operations. The AESO will continue to assess fault response to identify areas where more detailed review and modelling may be required. If warranted by the more detailed studies, the AESO will investigate approaches to improve fault response, such as revised or additional technical requirements, coordination of power electronic control systems, or use of synchronous condensers.

6 Conclusions

The AESO's system flexibility assessment was based on scenarios that provide a range of net demand variability conditions to be expected during the next ten years. Market, dispatch, and operational simulations modelled the ability of the electric system to maintain system reliability and respond to net demand variability and other conditions as the penetration of variable generation increases on the electric system through 2031.

The flexibility assessment did not identify immediate needs for system flexibility enhancements to respond to net demand variability, provided that market practices continue to reflect the assumptions described in this report. However, the trends exhibited in the market and dispatch simulations suggest that requirements for additional flexibility will increase due to increasing penetration of variable generation, especially in the last half of the forecast period. The potential trends of some parameters are significant enough to support the development of incremental enhancements of system flexibility over the next few years through various AESO initiatives, as appropriate.

If the penetration of variable generation occurs faster than the scenarios examined in this flexibility assessment, then the need for incremental system flexibility enhancements will heighten. The AESO notes that variable generation projects are being rapidly developed in Alberta. If the strong growth trend of variable generation capacity continues, the AESO may need to respond by accelerating the development and implementation of system flexibility enhancements.

In addition, the results of operational simulations suggest some performance characteristics of the electric system are weakening and indicate an increasing need for measures to maintain reliability. In particular, the AESO has investigated recent system events and is implementing action plans to ensure frequency excursions can be managed and system reliability can be maintained.

Flexibility requirements continue to primarily reflect the timing of variable generation capacity additions. The flexibility assessment identified the following trends, which may require the development and implementation of mitigation measures over the next few years to maintain a reliable transmission system and well-functioning markets:

- The ability to respond to net demand changes through energy market dispatch may be supported by faster ramp rates and stable response delay of dispatchable generation, based on trends illustrated in Figures 4-4 and 4-5.
- The ability to respond to net demand changes through energy market dispatch will be increasingly challenged by more frequent and larger net demand changes and more frequent and larger wind generation constant-ramp forecast errors, based on trends illustrated in Figures 4-1 and 4-2, Table 4-3, and Figure 4-8.
- Dispatchable generation will be subject to increasing cumulative absolute dispatch ramp, and baseload generating assets will be subject to more frequent on/off cycling, based on trends illustrated in Figures 4-9 and 4-10.
- Although greater amounts of regulating reserve will be utilized in responding to more frequent and larger net demand changes, regulating reserve will provide a smaller proportion of the total response to net demand changes, based on trends illustrated in Figures 4-6 and Table 4-7.
- Instantaneous interchange with adjacent balancing authorities will be increasingly relied on to respond to more frequent and larger net demand changes, based on simulated area control error trends illustrated in Figure 4-6, Table 4-7, and Figure 4-13.

- System reliability may decrease with very low levels of supply cushion occurring more frequently in the Clean-Tech Scenario, based on trends illustrated in Figure 4-11.
- Market operation may be challenged with increasing frequency of supply surplus in both the Reference Case and Clean-Tech Scenario, based on trends illustrated in Figure 4-12.
- Indicative market impact of responding to changes in net demand that cannot be perfectly predicted increases but remains small over the forecast period, as illustrated in Figure 4-14.
- The risk of low system frequency conditions will increase as lower levels of system inertia from online generators occur more frequently over the forecast period and if primary frequency response continues to decrease, as illustrated in Figures 5-1, 5-2, and 5-3.
- Mitigation measures may be required where a group of grid-following inverter-based resources connect in an area where the electric system has weak fault response, as illustrated in Figure 5-4.

These trends collectively indicate that requirements for system flexibility will materially increase to maintain system reliability during the next ten years in response to increasing net demand variability and increasing variable generation capacity. The ramping capability provided through energy market dispatch and regulating reserve will remain the primary mechanism to balance supply and demand for the next several years but will be increasingly challenged to respond to net demand variability as the penetration of variable generation increases in the second half of the forecast period.

For any remaining supply-demand imbalances that are not addressed through ramping capability, instantaneous interchange with adjacent balancing authorities will increasingly be used, and maintaining area control error within acceptable performance ranges will become more difficult over the forecast period.

However, the dispatchable resources on the system will become more capable of faster ramping and will maintain their quick response to dispatch instructions. The market impact of responding to changes in net demand is also expected to remain small.

In conclusion:

- This *2022 System Flexibility Assessment* indicates that trends of weakening system flexibility are accelerated compared to the *2020 System Flexibility Assessment*.
- The trends suggest potential mitigation measures should be evaluated over the next few years to prepare for possible implementation in the mid-2020s.
- The need for system flexibility enhancements results primarily from increasing penetration of variable generation. As the growth in variable generation is challenging to forecast, implementation may need to occur earlier if the penetration of variable generation occurs faster than the scenarios examined in this flexibility assessment.

The AESO is committed to ensuring we have the price signals, technical requirements, and products needed to sustain system reliability as the generation fleet and the industry more broadly transform. We will continue to assess different fleet scenarios (such as through the Net-Zero Emissions Pathways initiative) and explore potential implementation of options, including technical requirements, market design changes, and new ancillary service products, as appropriate. We will continue to engage stakeholders as we assess scenarios and explore options to strengthen system flexibility.

Potential mitigation measures that had been previously identified and paused in the absence of immediate need will be re-evaluated and assessed for effectiveness. Previously identified mitigation measures include adjustments to the energy market price cap and floor framework, tightened dispatch tolerance requirements, potential new reliability products, and shorter settlement intervals. Other mitigation measures have been implemented or are in progress, including the fast frequency response pilot project, regulating reserve volume optimization, and improved utilization of wind and solar forecasts.

Additional mitigation measures will be investigated and considered, including synthetic inertia for inverter-based resources, dynamic automatic generation control, and improvements to system controller dispatch practice.

Although the timing of the need for such mitigation measures does not appear to be immediate, the AESO will monitor generation and load development to determine whether flexibility requirements are accelerating faster than anticipated in this assessment. However, longer-term trends identified in this flexibility assessment suggest that potential mitigation measures to address weakening system flexibility should be explored.

The AESO performs and publishes flexibility assessments to provide stakeholders with visibility to the impacts of changes occurring on the Alberta electric system, and to enable their effective participation in the AESO's stakeholder engagement processes. The results of the *2022 System Flexibility Assessment* support continued monitoring of system flexibility. As explained in section 2 of this report, the AESO will periodically update the flexibility assessment to proactively identify when system flexibility may need to be enhanced.

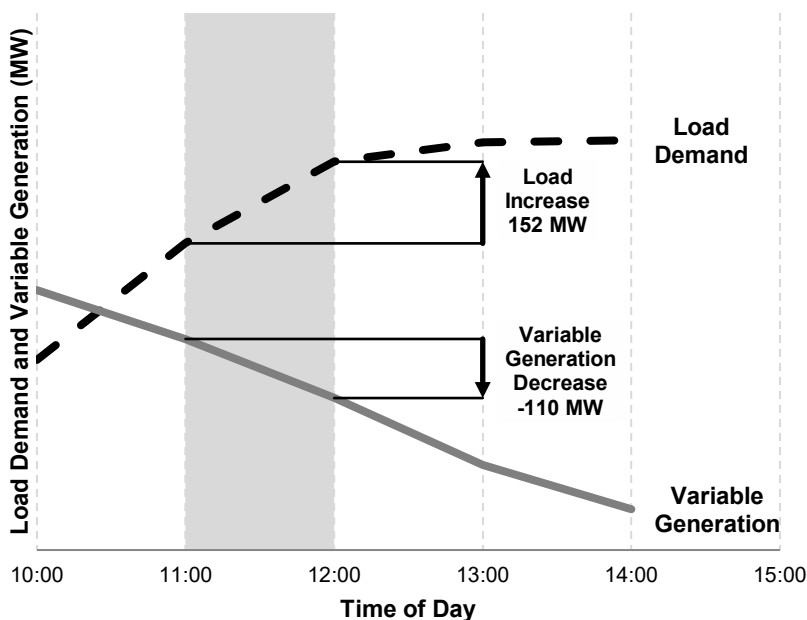
Appendices

A Net demand variability

In electric systems without a significant amount of variable generation, supply and demand imbalances are mainly due to the demand variability of load. As more variable generation is integrated into the electric system, additional balancing capability may be required to respond to the production variability of the variable generation. The overall variability of the combined load demand and variable generation production is defined as net demand variability, where the change in net demand is determined as change in load demand minus change in variable generation production.

Figure A-1 illustrates an example of the change in net demand over an hour that results from an increase in load demand and a decrease in variable generation production.

Figure A-1 – Net demand change resulting from load increase and variable generation decrease



Change in net demand is determined as change in load demand minus change in variable generation production. For example, during the hour from 11:00 to 12:00 that is shaded in the illustration at left, load demand increases by 152 MW while variable generation production decreases by 110 MW. The change in net demand during the hour is therefore:

$$152 \text{ MW} - (-110 \text{ MW}) = 262 \text{ MW}$$

Net demand variability requires the electric system to respond within a short timeframe. The timeframe may be as long as one hour to a few days before real-time, for resource scheduling, to as short as within minutes to about an hour, for real-time dispatch and deployment.

In Alberta, net demand variability includes imbalances resulting from demand and from wind and solar generation, which together comprise variable generation. The dispatchable generation relied on to provide system flexibility includes coal-fired, gas-fired steam, cogeneration, combined cycle, simple cycle, hydro, and other dispatchable generation. System flexibility response to net demand variability is also provided through wind and solar power management and interchange with adjacent balancing authorities.

B Generation and load included in Reference Case and Clean-Tech Scenario

This system flexibility assessment is based on the Reference Case and Clean-Tech Scenario included in the *AESO 2021 Long-term Outlook* published in June 2021 as the foundation for load and generation assumptions.

- The Reference Case from the *2021 Long-term Outlook* is used as the Reference Case in this system flexibility assessment.
- The Clean-Tech Scenario from the *2021 Long-term Outlook* is used as a scenario to assess system flexibility with higher penetration of renewable generation and energy storage assets.

Tables B-1 and B-2 summarize the year-end installed generation capacity by source and Alberta internal load included in each scenario for each year from 2019 to 2031. Capacities for 2019-2021 are actual amounts, and capacities for 2022-2031 are forecast amounts. The generation capacities exclude distributed energy resources of less than 5 MW.

Table B-1 – Year-end peak Alberta internal load and installed generation capacity by source in Reference Case from AESO 2021 Long-term Outlook, MW

Generation Source	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Dispatchable Generation													
Coal	5,183	4,132	2,530	155	155	155	155	0	0	0	0	0	0
Dual Fuel	540	940	155										
Gas-Fired Steam	0	0	1,981	4,305	4,305	4,305	4,305	4,305	4,305	4,192	4,192	4,122	4,122
Cogeneration	5,093	5,131	5,247	5,188	5,188	6,039	6,129	6,174	6,264	6,309	6,399	6,489	6,579
Combined Cycle	1,790	1,798	1,798	1,748	2,648	2,648	2,648	2,648	2,648	2,648	2,648	2,648	2,648
Simple Cycle	855	1,076	1,182	1,223	1,240	1,257	1,273	1,290	1,307	1,323	1,340	1,357	1,351
Hydro	894	894	894	894	894	894	894	894	894	894	894	894	894
Storage		30	50	35	40	45	45	45	55	55	65	65	65
Other	381	381	382	423	423	423	423	423	423	423	423	423	423
Subtotal Dispatchable	14,736	14,382	14,219	13,971	14,893	15,766	15,872	15,779	15,896	15,844	15,961	15,998	16,082
Variable Generation													
Solar	15	107	736	954	954	1,004	1,004	1,004	1,004	1,004	1,004	1,004	1,054
Solar/Storage	0	0	0	35	35	35	35	35	35	35	35	35	35
Wind	1,781	1,781	2,269	3,327	3,327	3,327	3,327	4,007	4,457	4,607	4,607	4,607	4,617
Subtotal Variable	1,796	1,888	3,005	4,316	4,316	4,366	4,366	5,046	5,496	5,646	5,646	5,646	5,706
Alberta Internal Load													
Peak Load	11,471	11,698	11,729	11,771	11,901	11,961	12,065	12,154	12,257	12,373	12,362	12,413	12,548

Note: Numbers may not add due to rounding

Table B-2 – Year-end peak Alberta internal load and installed generation capacity by source in Clean-Tech Scenario from AESO 2021 Long-term Outlook, MW

Generation Source	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Dispatchable Generation													
Coal	5,183	4,132	2,530	961	561	0	0	0	0	0	0	0	0
Dual Fuel	540	940	155										
Gas-Fired Steam	0	0	1,981	3,099	3,099	3,099	2,916	1,735	935	935	935	935	935
Cogeneration	5,093	5,131	5,247	5,188	5,188	6,039	6,129	6,174	6,264	6,309	6,399	6,489	6,579
Combined Cycle	1,790	1,798	1,798	1,748	3,364	4,822	4,822	4,822	4,822	4,822	4,822	4,822	4,822
Simple Cycle	855	1,076	1,182	1,237	1,261	1,284	1,308	1,331	1,355	1,379	1,402	1,426	1,449
Hydro	894	894	894	894	894	894	894	894	894	894	894	894	894
Storage		30	50	135	210	460	785	785	835	835	885	885	935
Other	381	381	382	423	423	423	423	423	423	423	423	433	443
Subtotal Dispatchable	14,736	14,382	14,219	13,685	15,000	17,021	17,277	16,164	15,528	15,597	15,760	15,884	16,057
Variable Generation													
Solar	15	107	736	954	1,104	1,104	1,104	1,204	1,354	1,524	1,704	1,784	1,964
Solar/Storage	0	0	0	45	130	195	195	195	195	195	195	195	195
Wind	1,781	1,781	2,269	3,407	3,507	3,707	3,907	4,167	4,207	4,467	4,497	4,497	4,497
Subtotal Variable	1,796	1,888	3,005	4,406	4,741	5,006	5,206	5,566	5,756	6,186	6,396	6,476	6,656
Alberta Internal Load													
Peak Load	11,471	11,698	11,729	11,805	11,949	12,069	12,189	12,288	12,344	12,454	12,453	12,600	12,768

Note: Numbers may not add due to rounding