2020 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 2020 System Flexibility Assessment* provides a summary of system flexibility needs and capabilities forecast from 2021 to 2030. The data summarized in the tables and figures 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 balancing supply and demand by the hour or minute. As more variable generation is integrated into the electric system, additional balancing capability may be required to respond to the combined variability of load demand and variable generation, which is referred to as net demand variability.

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 scenarios were modelled through market simulation and dispatch simulation to assess parameters that will indicate the ability of the electric system to respond to net demand variability through 2030.

The simulation results allowed assessment of ramp distribution, ramping capability, responses to net demand change, forecast uncertainty, cumulative asset ramping, asset on/off cycling, simulated area control error, and indicative market impact.

The flexibility assessment did not identify any emerging needs for immediate system flexibility enhancements, provided that market practices continue to reflect the assumptions described in this report. The trends exhibited by the parameters simulated over the forecast period suggest that requirements for additional flexibility are likely to increase gradually, allowing incremental enhancements of system flexibility to be developed through various AESO initiatives, as appropriate.

The results of the assessment support continued monitoring and periodic assessments of system flexibility. As explained in section 2.4 of this report, 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's Flexibility Roadmap[1] sets out a plan to sustainably monitor and forecast flexibility capabilities and needs and proactively plan to enhance system flexibility through tools, processes, standards, rules, etc. as appropriate. If the forecast 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. System flexibility 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, and other capabilities.

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. Longer-term aspects of system flexibility such as planning for new transmission resources, and shorter-term aspects such as system stability capabilities including inertia and frequency response, are addressed through other AESO initiatives.

This assessment was prepared because, over the next several years, the AESO expects that system flexibility will need 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.

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.

This assessment does not examine the effects of increasing variable generation and other changing conditions on requirements to maintain system reliability, such as contingency reserve requirements, system inertia, and frequency response.

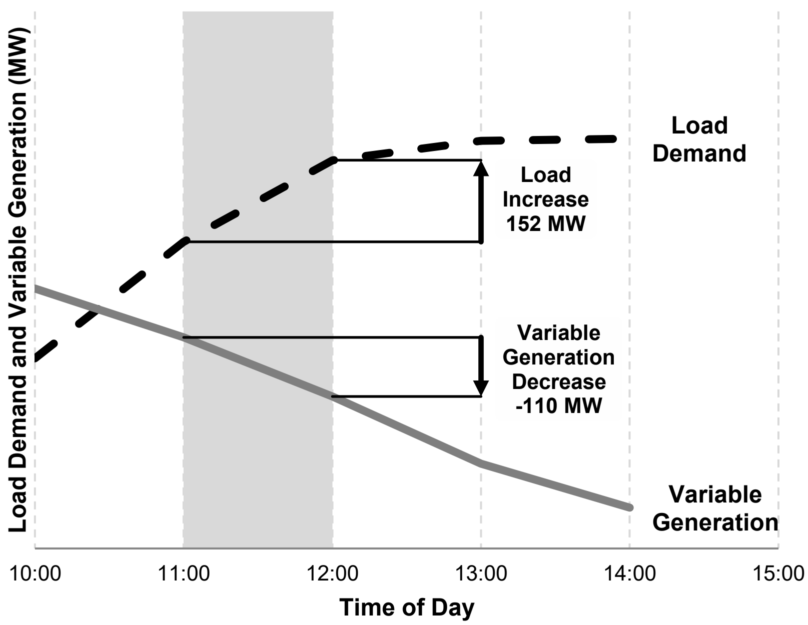
[1] Presentation from Energy Storage Roadmap & Flexibility Roadmap Information Session, August 7, 2019, available at https://www.aeso.ca/assets/Uploads/Energy-Storage-Session-Aug-7-8.7.19-Final.pptx

2.2 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 2-1 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 2-1 – 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 MW – (-110 MW)
= 262 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, cogeneration, combined cycle, simple cycle, hydro, and other dispatchable generation. As mentioned in the previous section, system flexibility is also provided through wind and solar power management and interchange with adjacent balancing authorities.

2.3 Previous assessments of system flexibility

The AESO has been assessing various aspects of system flexibility for many years. Prompted by increases in variable generation in Alberta, the impact of net demand variability was assessed in the energy and ancillary services working group during the AESO's capacity market development work in 2017 and 2018. At that time, net demand variability was expected to increase due to the increased variable generation resulting from the Renewable Electricity Program (REP).[2] The assessment concluded that the electric system may have sufficient flexibility and potential market enhancements should be further investigated.

In the *Dispatchable Renewables and Energy Storage* report[3] published in May 2018, the AESO further assessed net demand variability and whether the electric system has sufficient flexibility. The report concluded that there were no immediate concerns regarding sufficient flexibility in the electric system, but ongoing monitoring was required to proactively identify and address any emerging issues.

Following the report, the AESO began a flexibility roadmap to sustainably monitor and forecast flexibility capabilities and needs, and to plan to enhance system flexibility through tools, processes, standards, rules, ancillary service products, and other approaches as appropriate.

2.4 Monitoring and forecasting system flexibility

The AESO included monitoring of historical system flexibility parameters regarding market and system operation in the *2019 Annual Market Statistics* report[4] published in March 2020. The report introduced and reported information on net demand ramps, load forecast uncertainty, wind 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.

In this *System Flexibility Assessment* report, the AESO provides information on forecast system flexibility parameters, including several of the historical parameters included in the *2019 Annual Market Statistics* report. This assessment builds on previous assessments in the energy and ancillary services working group and the *Dispatchable Renewables and Energy Storage* report. This assessment reflects changes to the market since those previous assessments were completed, including the cancellation of the Renewable Electricity Program in June 2019, the release of the *AESO 2019 Long-term Outlook*[5] in September 2019, and ongoing changes to supply and demand in the energy market.

Periodic updates to system flexibility assessments will reflect the evolution of the transmission system, changes in generation and loads, and the adoption of new technologies. The AESO expects future system flexibility updates to be informed by other forward-looking information it provides, such as its *Long-term Outlook* forecasts. 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.

[2] Renewable Electricity Program, available at https://www.aeso.ca/market/renewable-electricity-program/
[3] Available at https://www.aeso.ca/market/current-market-initiatives/dispatchable-renewables/
[4] Available at https://www.aeso.ca/download/listedfiles/2019-Annual-Market-Statistics.pdf
[5] Available at https://www.aeso.ca/assets/Uploads/AESO-2019-LTO-updated-10-17-19.pdf

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 methodology similar to that of the previous assessments discussed in section 2.3 above and as described in more detail below.

3.1 Scenario-based analysis

A reference case is used to establish results from a baseline analysis, and analysis of additional scenarios provides 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.

The AESO anticipates coordinating system flexibility assessments with preparation of its *Long-term Outlook* forecasts and basing the assessments on the scenarios included in those *Long-term Outlook* forecasts. This system flexibility assessment used the *AESO 2019 Long-term Outlook*[6] published in September 2019 as the foundation for load and generation assumptions.

- The Reference Case from the *2019 Long-term Outlook* is used directly as the reference case in this system flexibility assessment.
- The Diversification Scenario from the *2019 Long-term Outlook* is used as a scenario to assess system flexibility with higher penetration of renewable generation.
- The reference case from the revenue sufficiency assessment in the AESO's current pricing framework review is used as an additional scenario to provide an assessment consistent with recent generation capacity addition, economic, and other information.

Analysis of the reference case and two scenarios 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 scenarios were prepared for a 10-year forecast period from 2021 to 2030. 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 above in section 2.4. 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 2019 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, load is forecasted to grow at a compound annual growth rate of 0.9 per cent until 2039. This is approximately half 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.

[6] Available at https://www.aeso.ca/assets/Uploads/AESO-2019-LTO-updated-10-17-19.pdf

- Approximately 4.5 GW of new generation capacity is expected to develop by 2030 for a total Alberta capacity of 19,853 MW in 2030.
- Natural gas-fired generation will become the predominant generation source as coal-fired capacity is expected to begin to co-fire or convert to natural gas starting in 2021 and continuing to a peak of 5,275 MW of converted coal-fired capacity in 2029.
- Near-term renewable generation will develop from REP projects and Alberta Infrastructure's support for solar programs.
- Additional unsubsidized renewable generation is expected to develop through competitive market mechanisms and support from corporate power purchase agreements (PPAs).

The reference case generation forecast implicitly assumes 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 to meet a specified level of reliability.

More information on the reference case is available in the *AESO 2019 Long-term Outlook*.

3.1.2 Diversification scenario

The diversification scenario used in this assessment is the Diversification Scenario included in the *AESO 2019 Long-term Outlook*, updated with recent project information to account for near-term renewable generation developments. The diversification scenario assumes that Alberta's economy will shift away from oil and gas and towards other more-diversified sectors to fuel economic growth.

In the diversification scenario, similar to the reference case, load is forecast to grow at a compound annual growth rate of 0.9 per cent until 2039.

The diversification scenario tests greater generation diversification with higher penetration of wind and solar generation. Under the diversification scenario, approximately 5.7 GW of new generation capacity is expected to develop by 2030 for a total Alberta capacity of 21,090 MW in 2030. Solar additions account for most of the increase compared to the reference case. The diversification scenario generation forecast includes capacity additions for specific generation technologies at levels different from the reference case.

More information on the diversification scenario is available in the *AESO 2019 Long-term Outlook*.

3.1.3 Revenue sufficiency scenario

The revenue sufficiency scenario used in this assessment updates the reference case with recent information, including recent load and generation developments, recent policy changes such as carbon pricing, and updates to assumptions such as capital costs and weighted average cost of capital.

In the revenue sufficiency scenario, similar to the reference case, load is forecast to grow at a compound annual growth rate of 0.9 per cent until 2039.

The revenue sufficiency scenario includes approximately 4.9 GW of new generation capacity expected to develop by 2030 for a total Alberta capacity of 20,160 MW in 2030. In contrast to the reference case and diversification scenario, the revenue sufficiency scenario does not assume a required level of long-term resource adequacy, but it tests the resource adequacy achieved through economic additions of generation capacity. Similar to the reference case, 5,267 MW of coal-fired capacity is assumed to co-fire or convert to natural gas beginning in 2021 and natural gas-fired generation will become the predominant generation source.

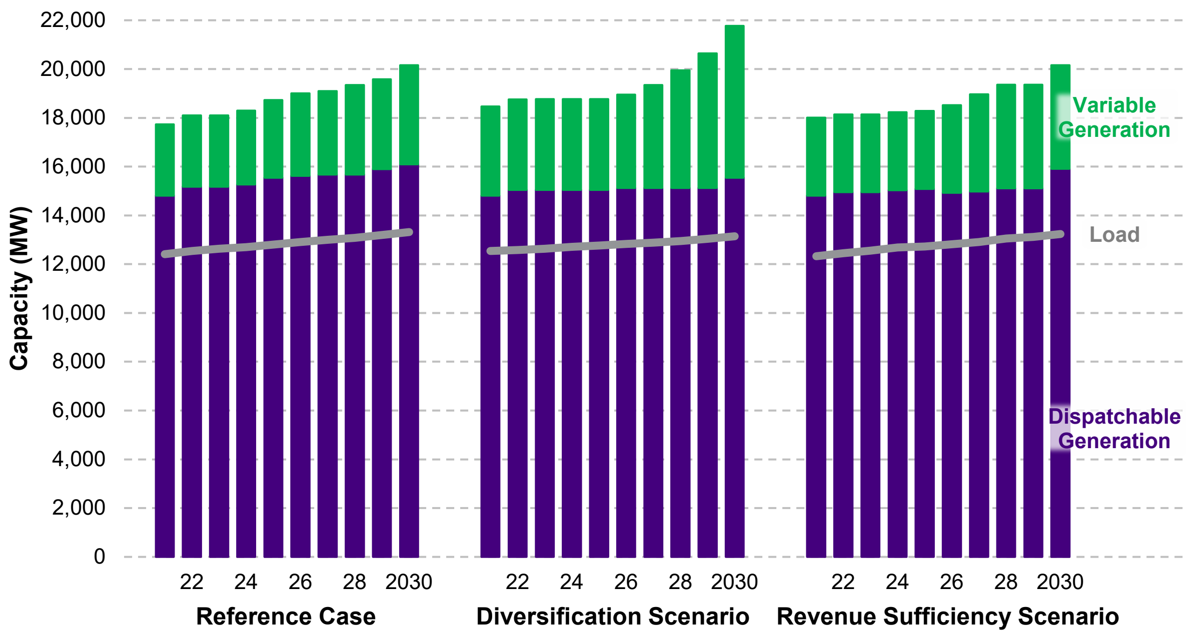
More information on the revenue sufficiency scenario is available in the pricing framework review presentation[7] from the stakeholder engagement session held on February 12, 2020, in the AESO's *Market Efficiency – Pricing Framework* initiative.

3.1.4 Load and generation capacity forecast for reference case and scenarios

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, diversification scenario, and revenue sufficiency scenario.

In Figure 3-1, dispatchable generation includes coal-fired, cogeneration, combined cycle, simple cycle, hydro, and other dispatchable generation. Variable generation includes wind and solar generation. Figure 3-1 does not include intertie capacity.

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



3.1.5 Impacts of COVID-19 pandemic and low oil prices on Alberta's power system

The analysis that informs this system flexibility assessment was completed prior to developments that have brought many uncertainties to the Alberta market. Energy consumption in 2020 has been affected by government and public health measures adopted to slow the spread of COVID-19 infections and actions taken by domestic energy producers in light of significant declines in oil prices.[8,9] On the supply

[7] Presentation available at https://www.aeso.ca/assets/Uploads/Session-1-February-12-2020-0207-V1-FINAL2.pdf

[8] *Impacts of the COVID-19 Pandemic and Low Oil Prices on Alberta's Power System*, April 21, 2020, https://www.aeso.ca/assets/Uploads/Pandemic-Low-Oil-Analysis-Summary-April-20-Final.pdf

[9] *An Update on the Impact of COVID-19 and Low Oil Prices on Alberta's Power System*, June 2020, https://www.aeso.ca/assets/Uploads/Impact-COVID-Low-Oil-Update-June-29-2020.pdf

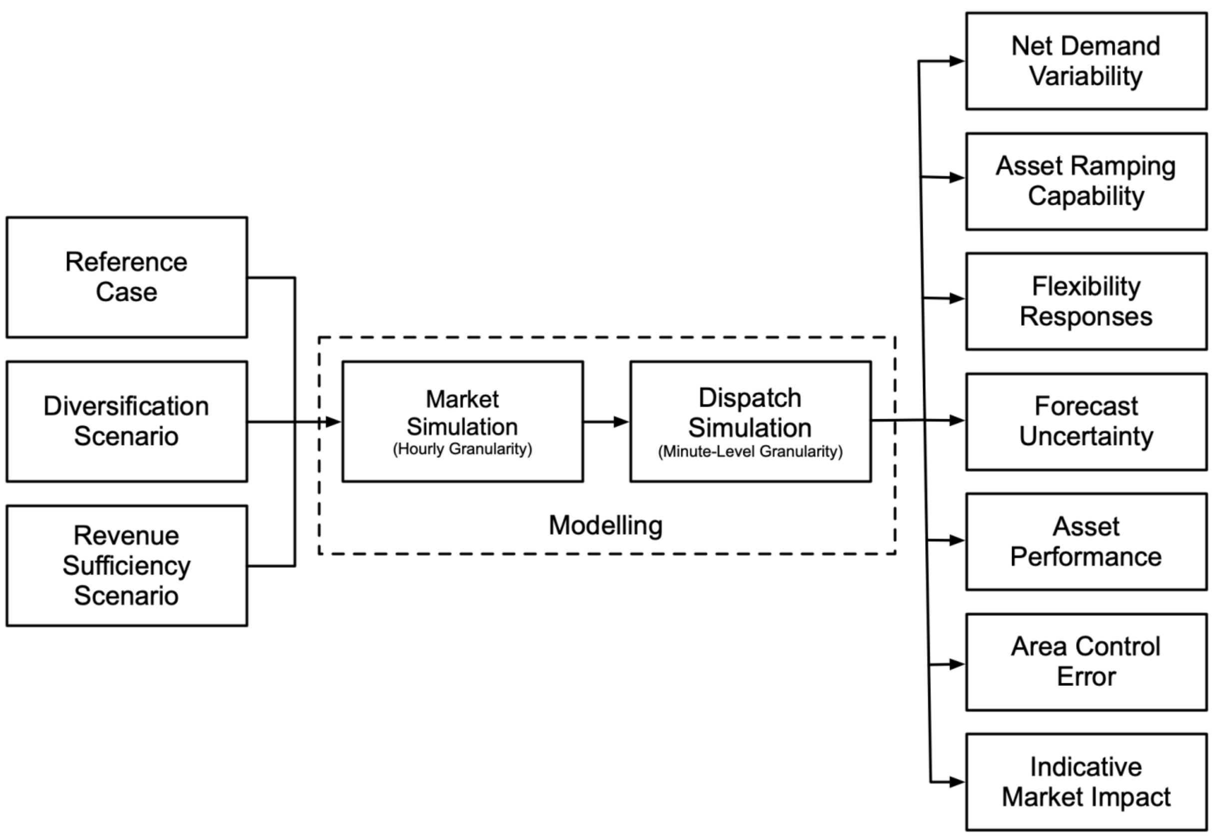
side, the pandemic has disrupted global supply chains of many sectors which, in turn, has delayed manufacturing and delivery of wind and solar generation equipment and has interrupted work on gas generating assets. Early indications of a pandemic-induced global economic downturn are expected to increase financing risks for energy projects and consumer adoption of new technologies, such as electric vehicles, that could have an impact on load.

The long-term impact on load and generation additions in Alberta due to factors such as the COVID-19 measures, low oil prices, and a global recession will depend on the length and magnitude of each and the ensuing reactions from consumers and investors. Should these factors have a temporary short-term impact on the Alberta electric industry, the scenarios presented in this system flexibility assessment will provide a reasonable range of net demand variability conditions to be expected over the long-term. The AESO will continue to monitor and report on these impacts, and future system flexibility assessments will incorporate relevant insights.

3.2 Analytical approach

The reference case and scenarios described in section 3.1 above were modelled through market simulation to create hourly load and generation profiles from 2021 to 2030. 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 2030. Figure 3-2 illustrates the analytical approach used for the system flexibility assessment.

Figure 3-2 – System flexibility analytical approach



3.2.1 Hourly market simulation

Aurora market modelling software was used to simulate the supply and demand characteristics of the reference case and each scenario. The Aurora software is a cost-production model that applies economic principles, commitment and dispatch logic, and bidding 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.

3.2.2 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.

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. The dispatch simulation also models the instantaneous interchange with adjacent balancing authorities.

3.2.3 Simulation assumptions

The modelling 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 by technology based on historical observed characteristics, including average time to respond to dispatches, average ramp-up and ramp-down rates, and minimum stable generation levels by unit under normal operation.
- Coal-to-gas conversion assets were modelled using generic coal-fired generation characteristics and estimates for characteristics (such as minimum stable generation) that were expected to substantially change, with the estimates based on limited observed values and industry discussion.
- Wind generating assets were modelled by hour and minute using historical generation profile data for 2015 and scaling the historical profiles by year to reflect forecast wind generation levels.
- Solar generating assets were modelled by hour and minute using the National Renewable Energy Laboratory's PVWatts Calculator[10] and scaling the profiles by year to reflect forecast solar generation levels.
- Load was similarly modelled by hour and minute using historical load profile data from 2014 to 2016 and scaling the historical profiles by year to reflect forecast load levels.

[10] NREL's PVWatts Calculator is made available by the U.S. Department of Energy (DOE)/National Renewable Energy Laboratory (NREL)/Alliance for Sustainable Energy, LLC (ALLIANCE) without warranty or liability; access to and use of the software is permitted under the terms set out at https://www.nrel.gov/disclaimer.html

- Wind and load profiles were synchronized using the 2015 weather year to reflect the correlation with weather for both wind generation and load.
- 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 interchange was based on a normal water year.
- Regulating reserve was modelled based on historical procurement, updated to reflect current practices resulting from the AESO's continuing monitoring and adjustment of regulating reserve procurement to meet appropriate reliability standards and operational benchmarks.
- 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 specific years of historical data used in the modelling reflect the AESO's development of its market and dispatch simulations and system flexibility assessments over several years. The simulation assumptions will 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 and dispatch outcomes that differ from the simulations completed for the system flexibility assessment.

4 Assessment results

System flexibility refers to 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 discussed in the previous section to assess the changes to flexibility parameters over the 10-year forecast period and between the scenarios. The flexibility parameters that were assessed included ramp distribution, ramping capability, forecast uncertainty, asset on/off cycling, 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 load, to variable generation or to net demand (which is 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 simulation through regulating reserve ramping up or down, via automatic generation control. 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 2021, 2025, and 2030 in each of the scenarios. 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 10 MW bins, while the vertical axis is the number of ramps in each bin.

As load is similar in all three scenarios, the variability of load remains similar in all three scenarios.

For 10-minute ramps of net demand in all three scenarios, the average size of larger ramps up and down (of at least ±50 MW) increases by about five per cent over the forecast period. As well, the frequency of larger ramps increases in all scenarios, primarily in the last five years of the forecast period. The wider distribution of larger ramps from 2025 to 2030 includes increases in frequency of about 10 per cent in the reference case and the revenue sufficiency scenario, and about 30 per cent in the diversification scenario.

For 60-minute ramps of net demand in all three scenarios, the average size of larger ramps up and down (of at least ±100 MW) increases from about five per cent to about 15 per cent, primarily in the last five years of the forecast period. As well, the frequency of larger ramps increases in all scenarios, also primarily in the last five years of the forecast period. The wider distribution of larger ramps from 2025 to 2030 includes increases in frequency of about five per cent in the reference case and the revenue sufficiency scenario, and about 15 per cent in the diversification scenario.

The increase in the size of ramps up and down, and in the frequency of larger ramps, are primarily resulting from increases in variable generation over the forecast period and to a lesser extent from increases in load over the forecast period.

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

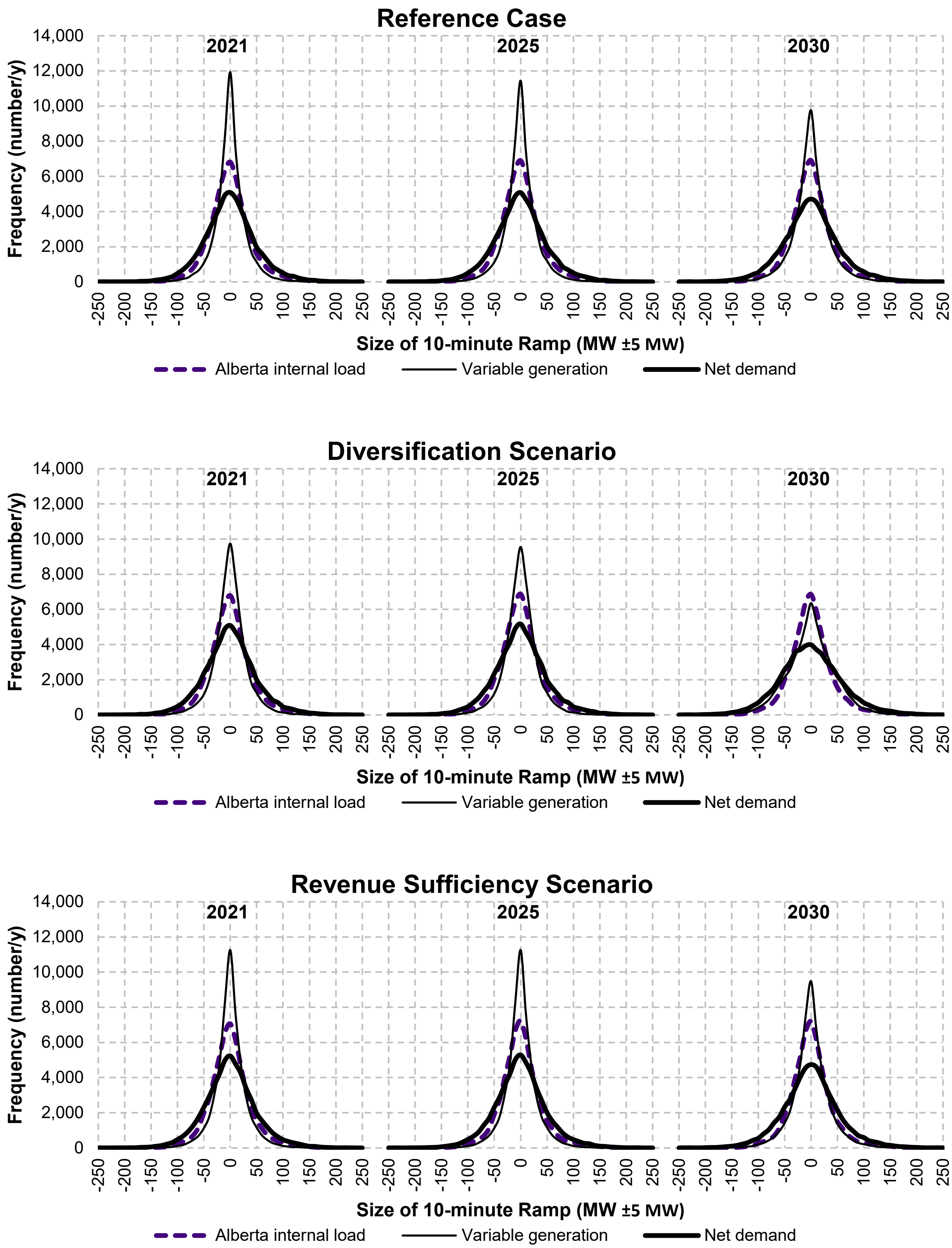
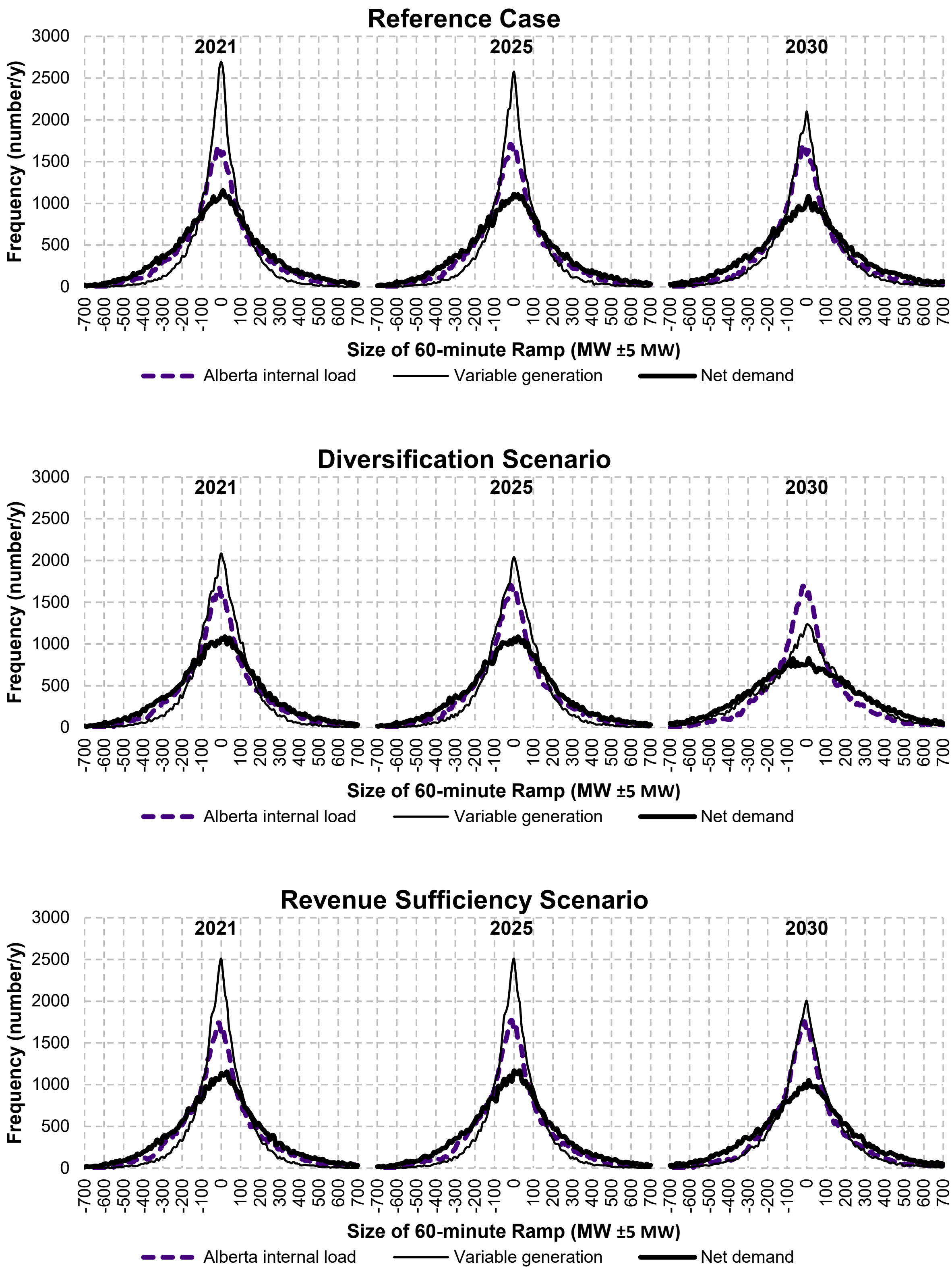


Figure 4-2 – Distribution of 60-minute ramps for load, variable generation, and net demand by scenario



4.2 Ramping capability

The net demand variability discussed in the previous section requires the electric system to respond within a short timeframe. As noted in section 4.1, larger 10-minutes ramps increase in frequency during the forecast period, especially over the last five years of the forecast period.

Dispatchable generation provides the balancing capability to match the size, speed and frequency of the net demand ramps. Dispatchable generation with sufficiently fast ramping and short response delay can match larger ramps that occur with greater frequency.

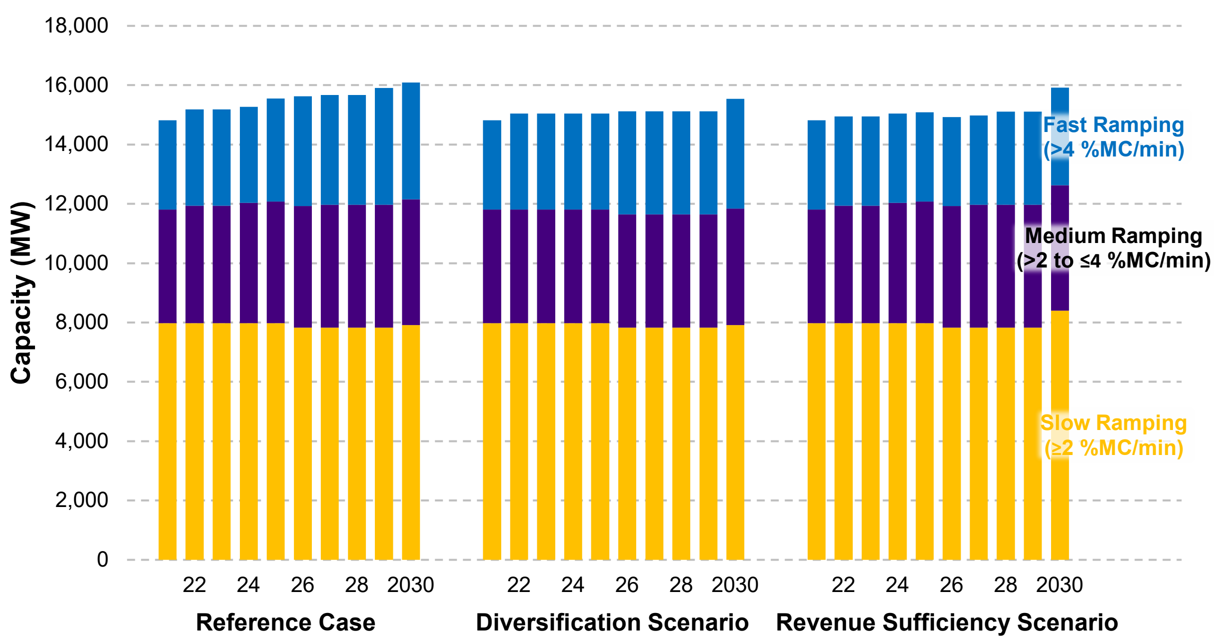
Figure 4-3 illustrates the average ramp rates of the dispatchable generation capacity simulated in the reference case, diversification scenario, and revenue sufficiency scenario. Ramp rate is measured as the average increase in output a generating asset can achieve in a 10-minute interval, expressed as a percentage of the generating asset's maximum capability per minute. The column segments in Figure 4-3 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 simple cycle generation, hydro generation, and some cogeneration);
- Medium ramping, capable of increases of more than two per cent up to four per cent of maximum capability per minute (primarily cogeneration and some hydro generation); and
- Slow ramping, capable of increases of up to two per cent of maximum capability per minute (primarily coal-fired, coal-to-gas conversion, and combined cycle generation).

Fast ramping generating capacity increases moderately over the forecast period in the reference case and diversification scenario. The increase results from simple cycle capacity additions over the forecast period. Increases in fast ramping generating capacity provide additional flexibility to respond to the frequency of larger net demand ramps illustrated in Figure 4-1.

Medium ramping generating capacity increases slightly over the forecast period in the reference case and revenue sufficiency scenario. The increase results from cogeneration additions over the forecast period. Increases in medium ramping generating capacity provide limited additional flexibility to respond to net demand ramps.

Figure 4-3 – Ramp rates of dispatchable generation by scenario

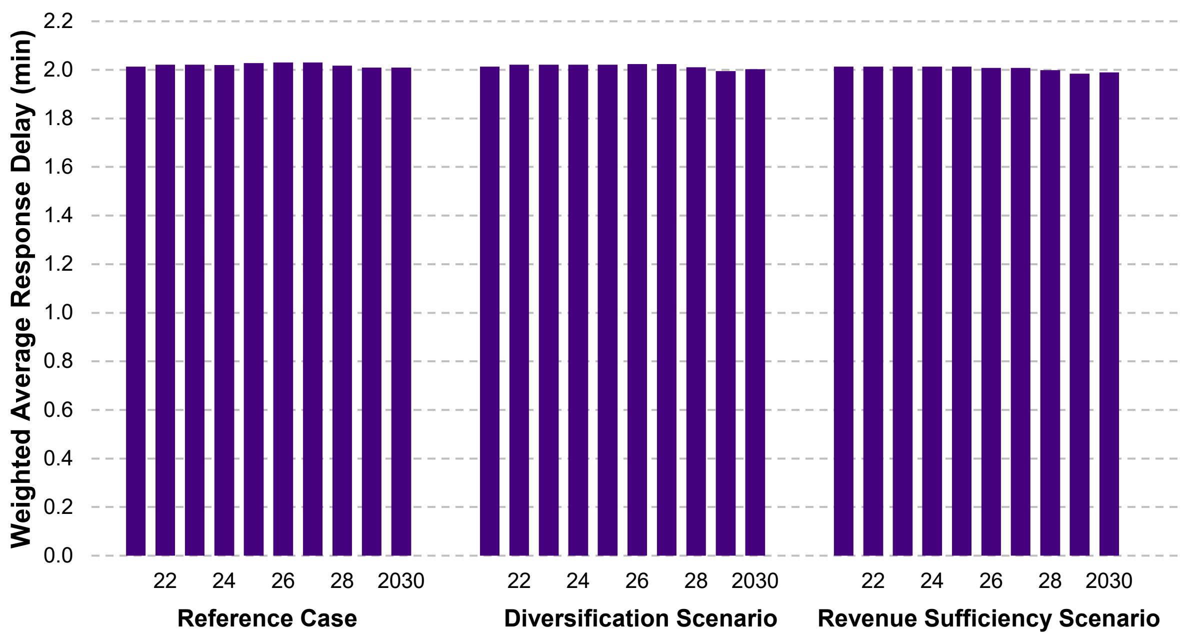


The ramping capability of dispatchable generation is also affected by the response delay from when a dispatch direction is issued to a generating asset to when the asset operator starts to ramp the asset to the directed dispatch level. Response delay occurs both when a generating asset is not operating 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 10-minute ramps that increase in frequency, especially over the last five years of the forecast period.

Figure 4-4 illustrates the average response delay of the dispatchable generation capacity included in the reference case, diversification scenario, and revenue sufficiency scenario. 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 historical observed characteristics by generation technology.

Response delay does not vary materially over the forecast period or between scenarios while, as illustrated in Figure 4-1, the frequency of larger net demand ramps increases over the forecast period in all scenarios.

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



4.3 System flexibility responses to net demand change

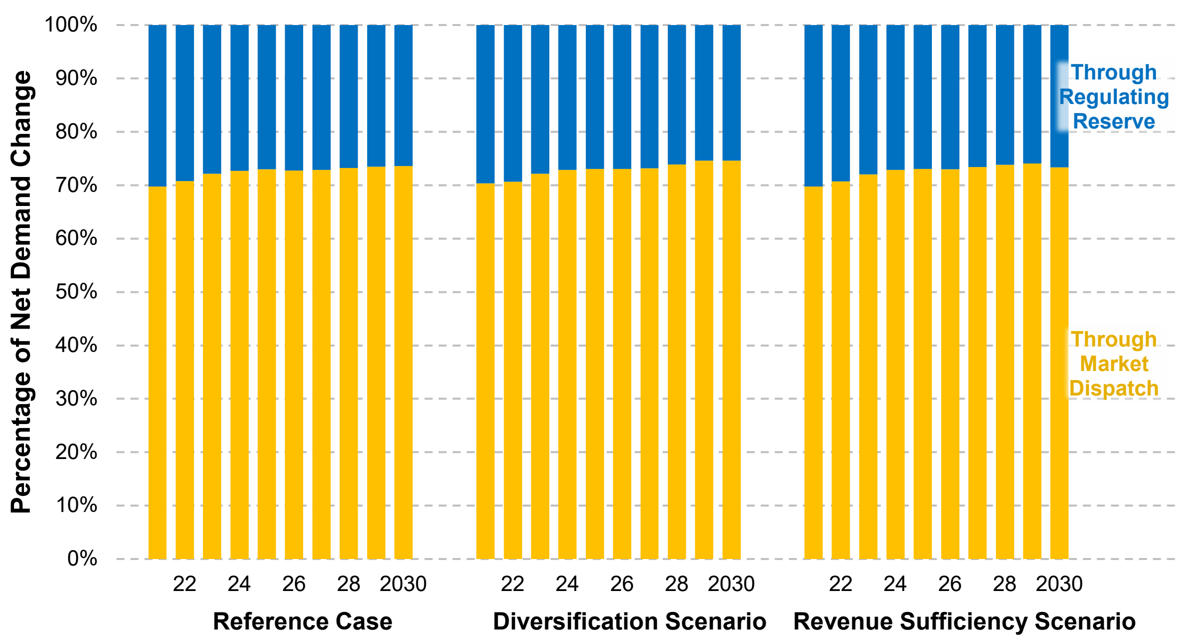
As discussed in section 2.1 of this flexibility assessment, the AESO currently relies on three primary approaches to provide system flexibility: energy market dispatch, regulating reserve, and wind and solar power management.

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. Comparing the energy market dispatch up or down, in MW, to the regulating reserve ramping up or down, in MW, indicates the proportions of 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 4-5 illustrates those proportions over the forecast period, for the reference case, diversification scenario, and revenue sufficiency scenario. Over the forecast period in all scenarios, from about 70 per cent to about 75 per cent of net demand change resulted in a response through energy market dispatch, with the remaining proportion of net demand change resulting in a response through regulating reserve. In response to load and variable generation increases over the forecast period, energy market dispatch increased while regulating reserve provided by dispatchable generation remained comparatively constant.

Wind and solar power management was allocated over all wind and solar generation facilities rather than to specific individual facilities and cannot be directly compared to the energy market dispatch and regulating reserve response to net demand change. However, wind and solar power management did not provide a significant amount of system flexibility during the forecast period.

Figure 4-5 – System flexibility responses to net demand change by scenario



4.4 Forecast uncertainty

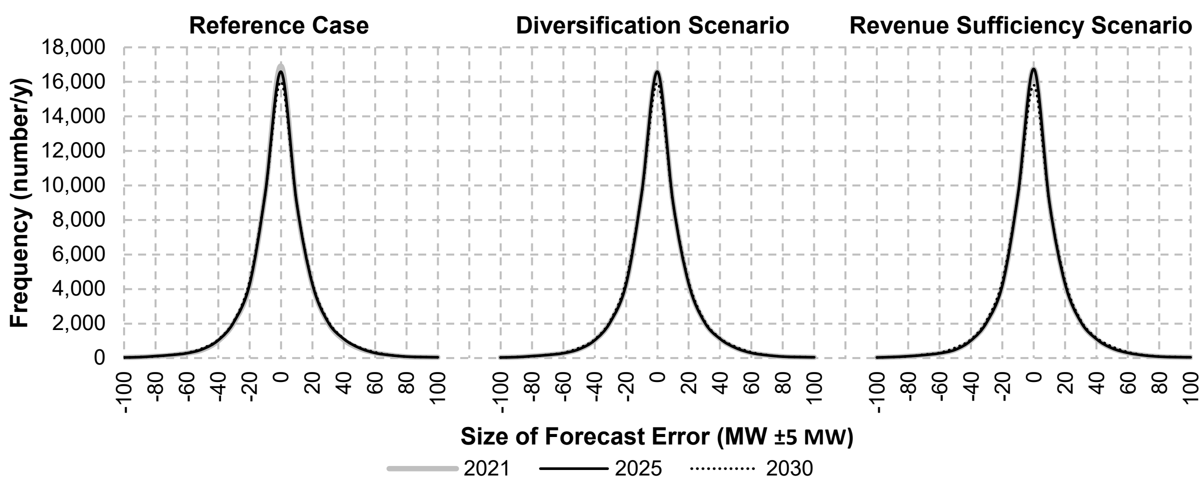
In Alberta's energy market, real-time dispatch is performed by a system controller through the manual process of dispatching energy in the merit order. Continuous real-time system controller dispatch decisions maintain the balance between changing supply and changing demand. Every minute, system controllers 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 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 3.2.3.

Figure 4-6 illustrates the distribution of the 10-minute-ahead wind generation forecast error over all hours in 2021, 2025, and 2030 for the reference case, diversification scenario, and revenue sufficiency scenario. The error at a given 10-minute interval is defined as the 10-minute-ahead forecast of wind generation minus the actual generation for that interval. The distribution of wind generation forecast error is nearly identical for 2021, 2025, and 2030 and is nearly symmetrical in each scenario. . The distribution also does not vary significantly between the three scenarios.

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

Figure 4-6 – Distribution of 10-minute-ahead wind generation forecast error by scenario



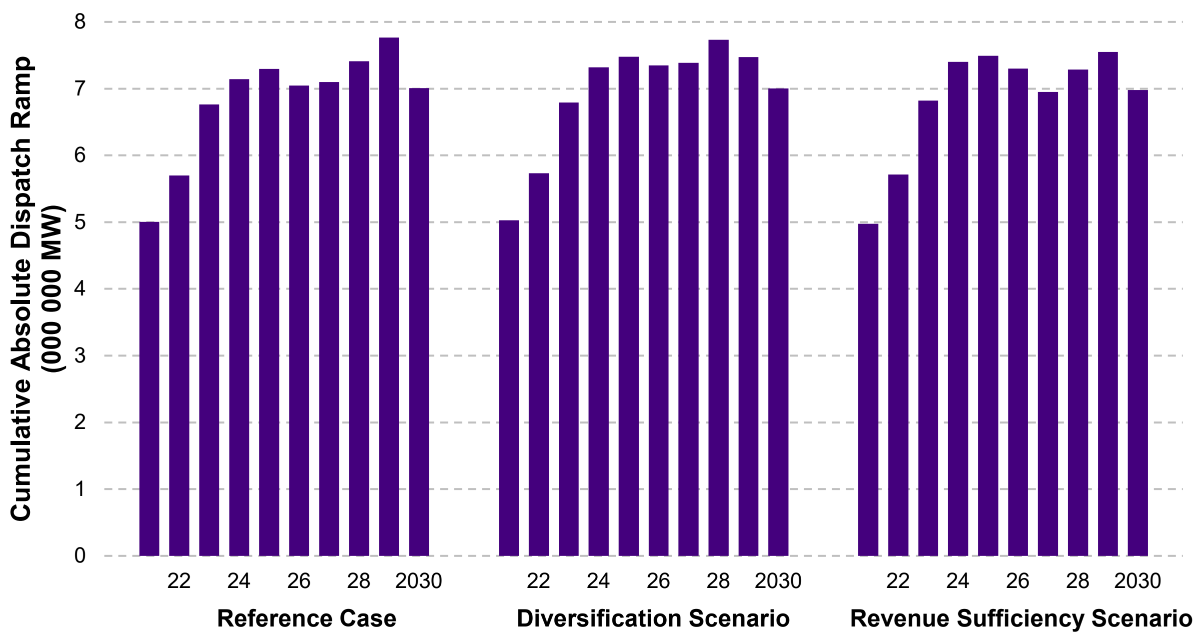
4.5 Cumulative dispatch ramping

As discussed in section 4.1, net demand variability is addressed through energy market dispatch up or down the merit order and through regulating reserve ramping up or down, via automatic generation control. Increasing net demand variability may result in larger ramp size, 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 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 ramping in MW. 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 4-7 illustrates the cumulative absolute dispatch ramp in aggregate over all 10-minute intervals in each year of the forecast period, in the reference case, diversification scenario, and revenue sufficiency scenario. Compared to 2021, cumulative absolute dispatch ramp increases by about 50 per cent over the forecast period in all scenarios. The increase in cumulative absolute dispatch ramp over the first four years of the forecast period results primarily from the change in generating asset characteristics reflecting just over 4,000 MW of coal-to-gas conversion over those years.

Figure 4-7 – Cumulative absolute dispatch ramp over 10-minute intervals by scenario



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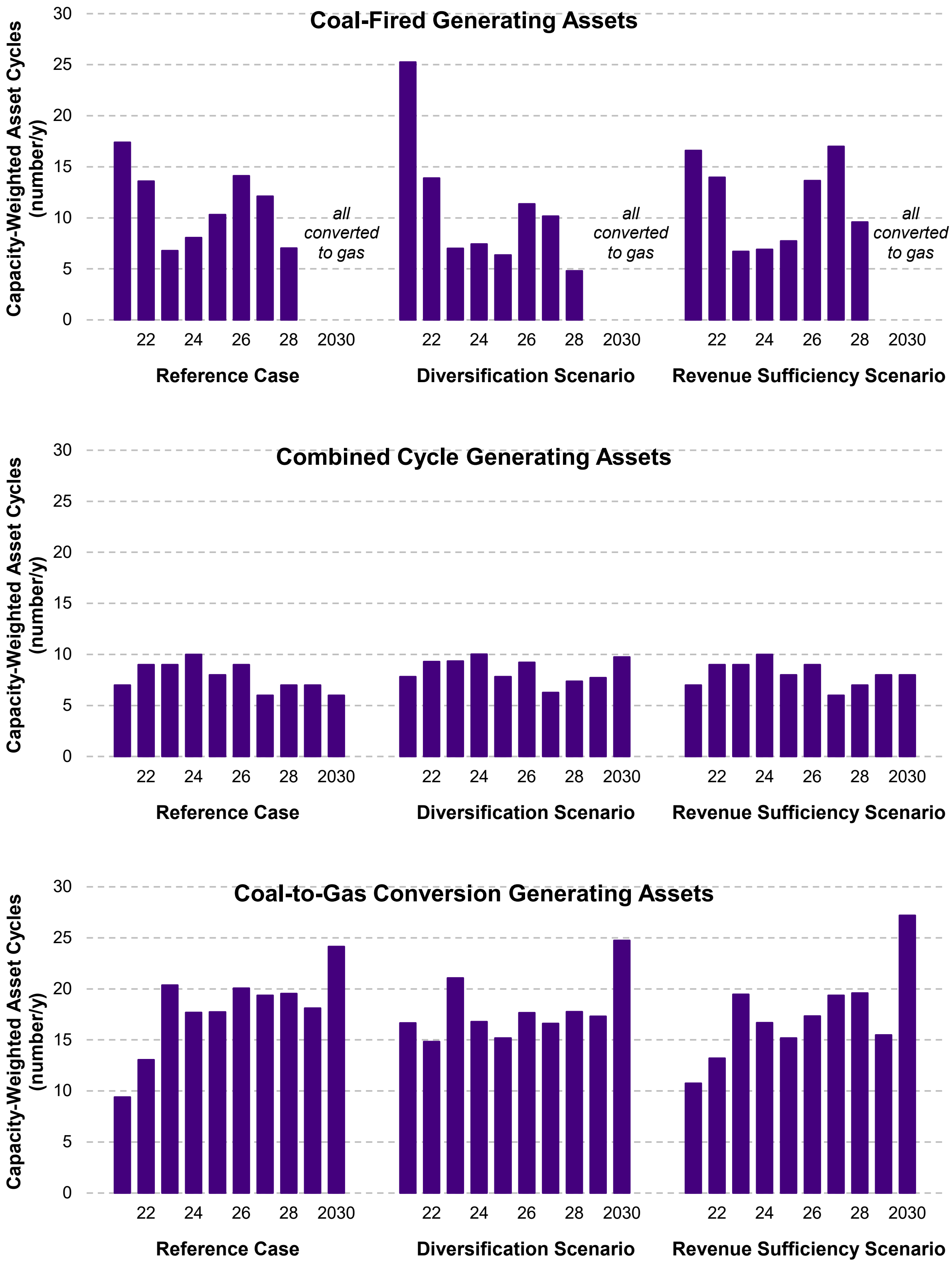
4.6 Asset on/off cycling

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 and combined-cycle generating assets. Frequent on/off cycling may also reduce the expected life of baseload generating assets. Figure 4-8 presents the average on/off cycles for baseload generating assets weighted by maximum capability, over the forecast period for the reference case, diversification scenario, and revenue sufficiency scenario.

The number of on/off cycles for each generating asset was first counted from the simulation for each year from 2021 to 2030. 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 coal-to-gas conversion 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, on/off cycling remains relatively constant for combined cycle generating assets while tending to increase for coal-to-gas conversion generating assets, in all three scenarios. In the first two years of the simulation, coal-fired generating assets experience more on/off cycling while combined cycle generating assets experience less on/off cycling, compared to later years in all three scenarios.

Figure 4-8 – Average number of on/off cycles per generating asset by technology by scenario



4.7 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.

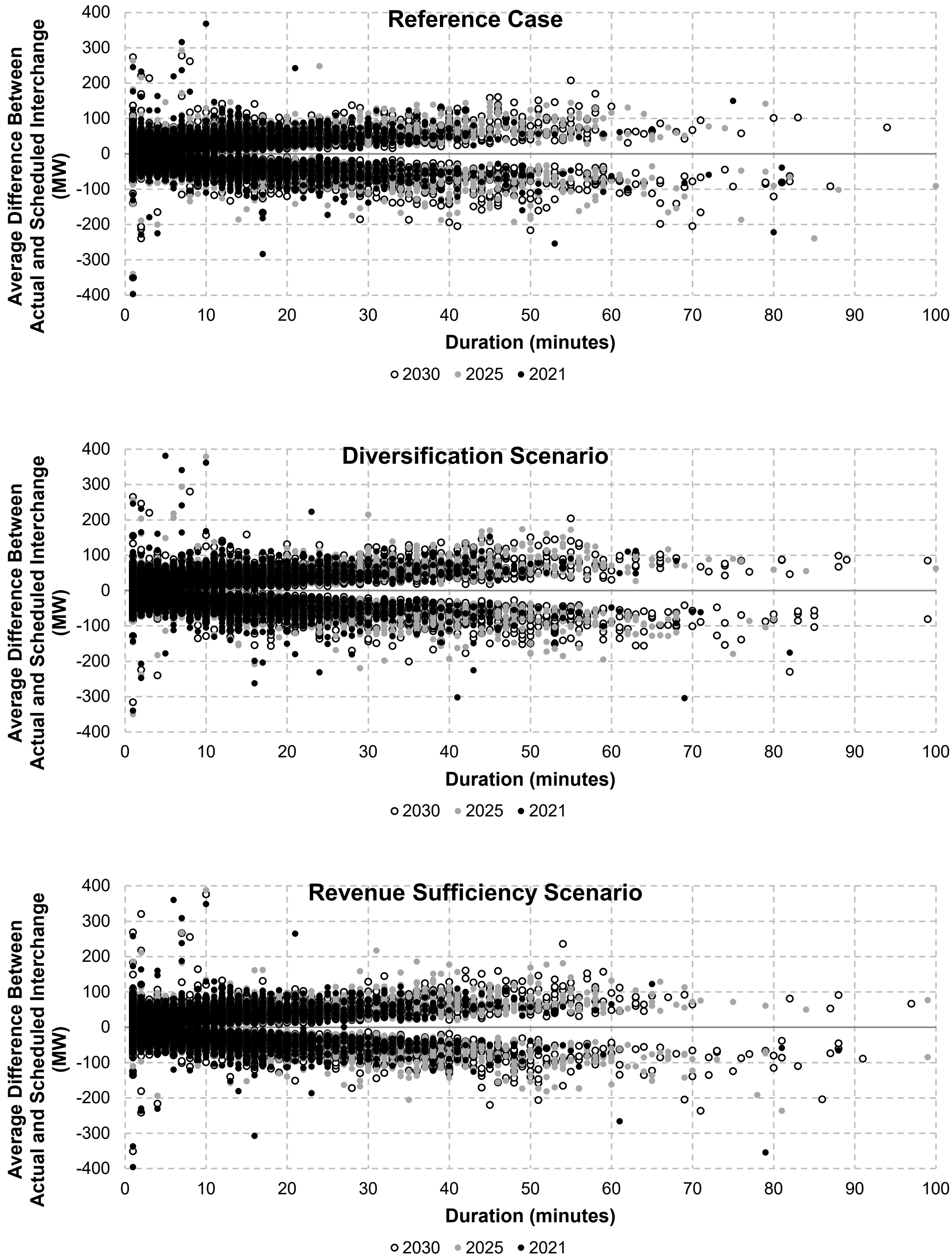
The dispatch simulation did not model the effects of frequency bias, time error, and metering error, and as a result the simulated area control error includes only the difference between actual interchange and scheduled interchange. The difference reflects the use of interchange to balance the Alberta electric system, in addition to the system flexibility provided by generating assets in the province. The use of interchange is governed by Alberta reliability standards and through the Western Electricity Coordinating Council (WECC), of which the AESO is a member.

Figure 4-9 illustrates the duration and size of simulated area control error in 2021, 2025, and 2030 for the reference case, diversification scenario, and revenue sufficiency 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 4-9 illustrates that simulated area control error appears with longer durations and greater average differences in the 2025 and 2030 simulations in all three scenarios.

The increase in simulated area control error durations and differences over the forecast period 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. The simulated area control error durations and differences are expected to remain with acceptable performance ranges over the forecast period.

Figure 4-9 – Duration and size of simulated area control errors by scenario



4.8 Indicative market impact of responding to net demand variability

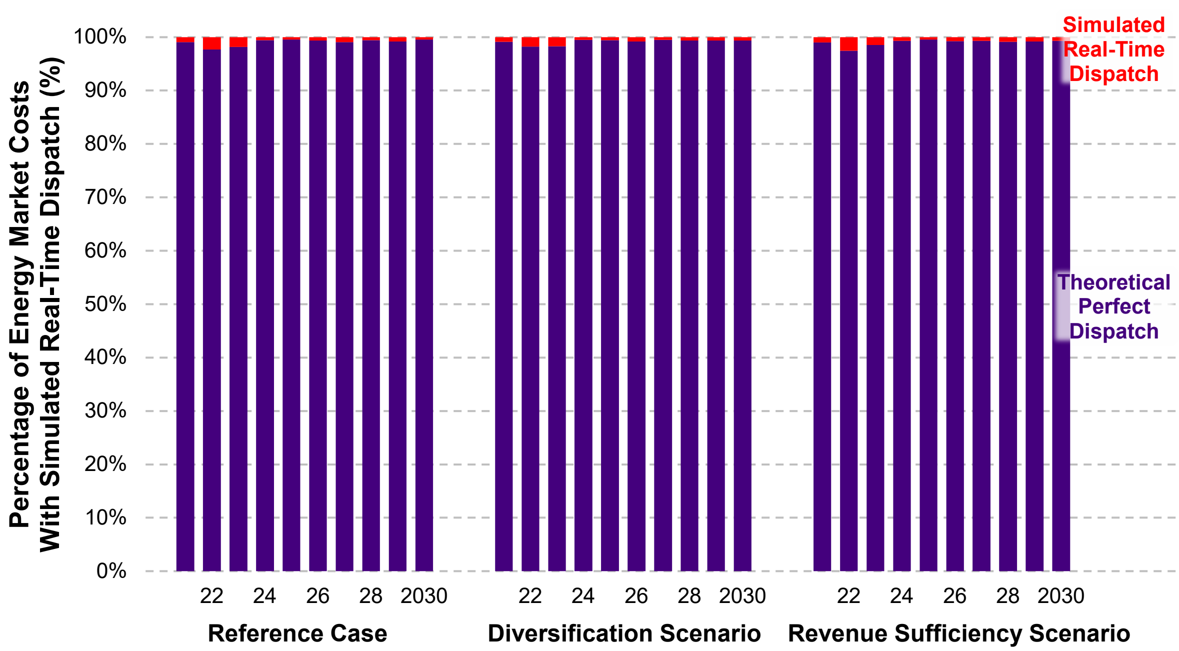
As discussed in section 2.1 of this report, system flexibility refers to the ability of the electric system to adapt to dynamic and changing conditions, including those related to net demand variability. If changes in net demand could be predicted with certainty over an interval, energy market dispatch 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 4-10 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, diversification scenario, and revenue sufficiency scenario. Energy market costs with theoretical perfect dispatch are 0.4 per cent to 2.5 per cent lower than with simulated real-time dispatch, in all years over the forecast period in all scenarios. On average, energy market costs with theoretical perfect dispatch are 0.9 per cent lower than with simulated real-time dispatch, with no significant changes observed over the forecast period or between scenarios.

The AESO has included this market impact information as indicative of the 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 3.2.2. The AESO expects to further examine the market impact of responding to net demand variability in future system flexibility assessments.

Figure 4-10 – Indicative market impact of responding to net demand change by scenario



5 Conclusions

The AESO's system flexibility assessment was based on scenarios that provide a range of net demand variability conditions to be expected over the next decade. Market simulations and dispatch simulations modelled the ability of the electric system to respond to net demand variability through 2030.

The flexibility assessment did not identify any emerging needs for immediate system flexibility enhancements, provided that market practices continue to reflect the assumptions described in this report. The trends exhibited by the parameters simulated over the forecast period suggest that requirements for additional flexibility are likely to increase gradually, allowing incremental enhancements of system flexibility to be developed through various AESO initiatives, as appropriate.

Flexibility requirements continue to reflect the timing of variable generation capacity additions. The flexibility assessment identified the following trends:

- Size of ramps up and down, and frequency of larger ramps, are expected to increase over the forecast period in conjunction with changes in net demand variability.
- No material changes are expected to the capacity of dispatchable generation available to be dispatched by system controllers to balance net demand variability over the forecast period, with a moderate increase in fast ramping generation capacity and little variation in average response delay.
- The proportions of net demand change responded to through energy market dispatch and regulating reserve remain stable over the forecast period.
- No material changes to wind generation forecast uncertainty were observed over the forecast period.
- Cumulative dispatch ramping increases by about 50 per cent over the forecast period, resulting primarily from the change in generating asset characteristics associated with coal-to-gas conversion.
- No material changes to on/off cycling were observed for combined cycle generating assets, with a tendency to increase on/off cycling for coal-to-gas conversion generating assets.
- Simulated area control error (that is, the differences between actual interchange and scheduled interchange) increases in duration and size over the forecast period, which 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.
- Indicative market impact of responding to changes in net demand that cannot be perfectly predicted remains small and stable over the forecast period.

These trends collectively indicate that dispatchable generation expected on the electric system over the next decade is capable of delivering system flexibility in response to increasing net demand variability. The ramping capability provided through energy market dispatch and regulating reserve is generally sufficient to balance supply and demand, while maintaining area control error within acceptable performance ranges over the forecast period. As well, the market impact of responding to changes in net demand is expected to remain small. Overall, increasing levels of net demand variability can be managed through system flexibility with minimal market changes.

In conclusion, this flexibility assessment indicates that energy market and regulating reserve capacity are expected to be capable of providing the system flexibility needed to respond to increasing variable generation, with no emerging needs for immediate system flexibility enhancements.

However, longer-term trends identified in this flexibility assessment suggest that potential additional approaches to provide system flexibility should be considered for exploration. The AESO will continue to explore such approaches in its current initiatives on energy market and ancillary services. The pricing framework review, dispatch tolerance requirements, more detailed asset-specific ramp tables, and sub-hourly settlement market initiatives, as well as the *AESO Energy Storage Roadmap* and the *AESO Distributed Energy Resources Roadmap*, may have implications for system flexibility.

Further evaluation of the impact of specific approaches or changes to practices could be simulated using the methodology described in this assessment, with the results compared to the results of this assessment as a baseline comparison. In particular, the AESO plans to assess system flexibility under conditions where asset dispatch response varies from historical observed characteristics. The results of the assessment will be shared with stakeholders as part of the dispatch tolerance stakeholder engagement planned for the second half of 2020.

The results of the flexibility assessment support continued monitoring and periodic assessments of system flexibility. As explained in section 2.4 of this report, the AESO expects to periodically update the system flexibility assessment to continue efforts to proactively identify when system flexibility may need to be enhanced.