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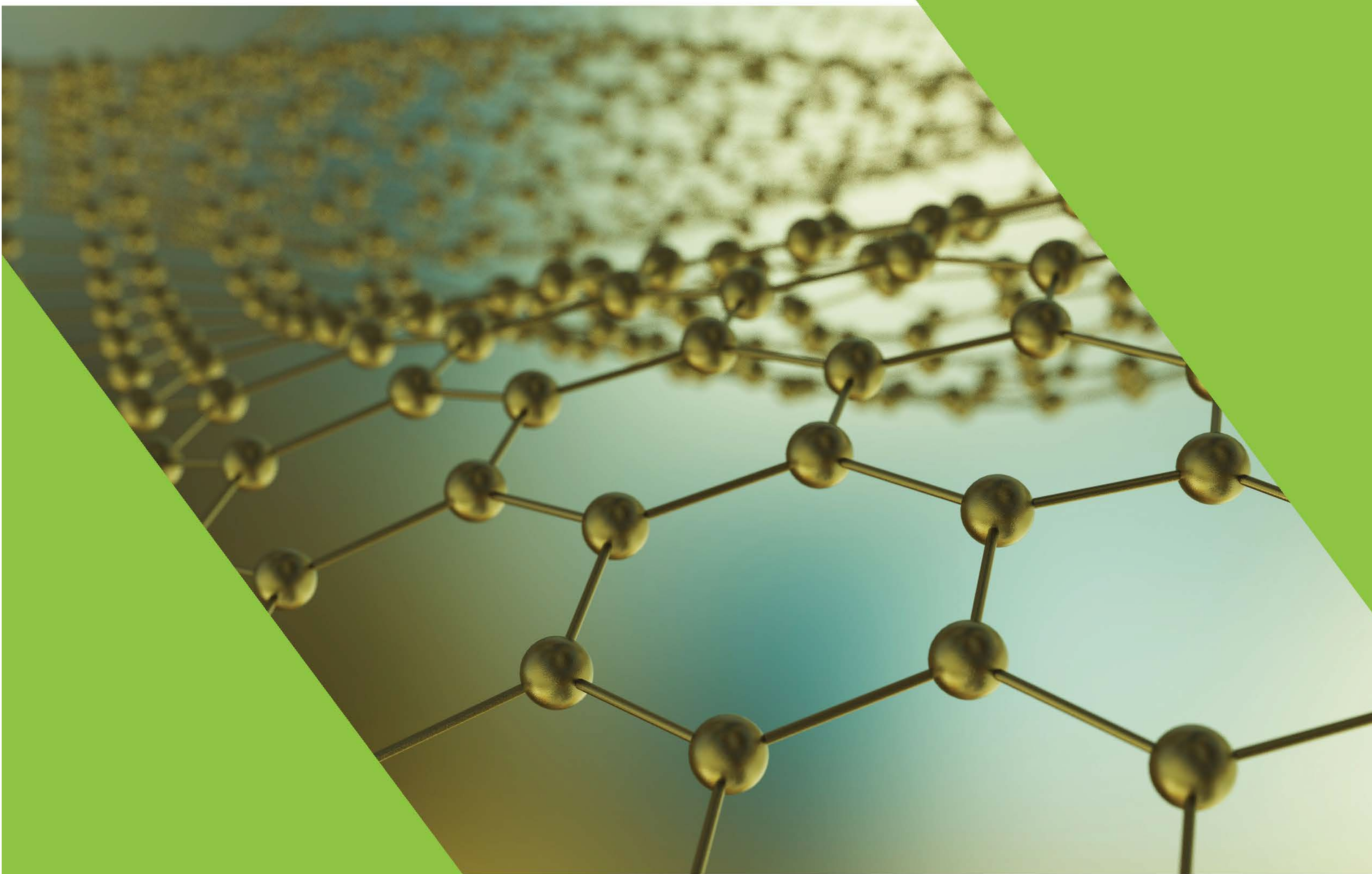

AESO 2023
Reliability Requirements Roadmap

MARCH 2023

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2021 LTO	AESO 2021 Long-term Outlook	2
2022 LTP	AESO 2022 Long-term Transmission Plan	7
AESO Net-Zero Report	AESO Net-Zero Emissions Pathways Report	2
Reliability Roadmap	2023 Reliability Requirements Roadmap	1
AC	Alternating Current	14
ACE	Area Control Error	48
AGC	Automatic Generation Control	23
AIES	Alberta Interconnected Electric System	1
AIL	Alberta Internal Load	14
AIR	Alberta Intertie Restoration	19
AESO	Alberta Electric System Operator	1
AGC	Automatic Generation Control	30
ARS	Alberta Reliability Standard	14
ATC	Available Transfer Capability	24
AVR	Automatic Voltage Regulator	36
BA	Balancing Authority	14
B.C. intertie	Alberta–British Columbia intertie	3
BESS	Battery Energy Storage System	33
CR	Contingency Reserve	30
CRPC	Chapel Rock to Pincher Creek	19
CSCR	Composite Short-circuit Ratio	75
DC	Direct Current	28
DER	Distributed Energy Resource	7
DFO	Distribution Facility Owner	36
EATL	Eastern Alberta Transmission Line	4
EMS	Energy Management System	56
EMT	Electromagnetic Transient	43
ERCOT	Electric Reliability Council of Texas	71
ESCR	Effective Short-circuit Ration	75
ESR	Energy Storage Resource	30
EUE MWh	Expected Unserved Energy in megawatt hours	46
EV	Electric Vehicle	11

Abbreviation	Term	Page Defined
FACTS	Flexible Alternating Current Transmission System	36
FFR	Fast Frequency Response	7
FNDR	Fast Net Demand Response	22
GFO	Generation Facility Owner	3
GVA	Gross Value Added	61
GW	Gigawatt	10
HVDC	High-voltage Direct-current	7
IBR	Inverter-Based Resource	4
IEEE	Institute of Electrical and Electronic Engineers	81
LCC	Line Commutated Converter	41
LSSi	Load Shed Service for imports	21
LTO	Long-term Outlook	7
LTP	Long-term Transmission Plan	7
MATL	Montana–Alberta Tie Line	3
MSSC	Most Severe Single Contingency	3
NDV	Net Demand Variability	30
NERC	North American Electric Reliability Corporation	21
NW-RSG	Northwest Reserve Sharing Group	56
PFR	Primary Frequency Response	3
PLL	Phase-Locked Loop	70
POI	Point Of Interconnection	35
PPC	Power Plant Controller	72
PSS®E	Power System Simulator for Engineering	42
PV	Photovoltaic	4
RAM	Resource Adequacy Model	46
RAS	Remedial Action Scheme	16
RC	Reliability Coordinator	14
RFI	Request for Information	7
RoCoF	Rate of Change of Frequency	3
SC	Synchronous Condenser	34
SCL	Short-circuit Level	39
SCR	Short-circuit Ratio	43
SCMVA	Short-circuit Megavolt Amperes	75
SG	Synchronous Generator	34

Abbreviation	Term	Page Defined
STATCOM	Static Synchronous Compensator	77
TFO	Transmission Facility Owner	42
TSAT	Transient Security Assessment Tool	42
TTC	Total Transfer Capability	16
UFLS	Under-frequency Load Shedding	2
SVAR	Static Volt-ampere Reactive	77
WECC	Western Electricity Coordinating Council	18
WSCR	Weighted Short-circuit Ratio	39

1 Executive Summary

The AESO is preparing the power system for a period of significant change. We are taking action to ensure Alberta's grid is reliable and able to adapt to increasing levels of renewables generation, distributed resources, energy storage, other forms of low-carbon generation, and increasing electrification.

Introduction & Context

The Alberta Interconnected Electric System (AIES) is undergoing a period of rapid transformation. The development of new technologies, rapid reductions in costs of some technologies, focused carbon policies and a societal desire for cleaner forms of energy are driving significant changes in the generation supply mix and demand profiles within Alberta's electricity sector. An increasing proportion of electricity is coming from renewable or other low-carbon sources, with increasing electricity demands from transportation, heating, industrial applications, carbon capture usage and storage and other areas also emerging. These changes are already impacting Alberta's power grid and will continue to do so into the future. While this shift creates investment opportunities and helps the province to progress towards a decarbonized electricity system and economy, it also presents significant operational challenges.

The Alberta Electric System Operator (AESO) has a leadership role in enabling this transformation. The AESO acts in the public interest and is responsible for providing for the safe, reliable, and economic operation of the AIES. To fulfill its mandate, the AESO must assess the potential challenges that a transforming grid brings and take appropriate action where necessary to ensure these objectives continue to be met.

This *2023 Reliability Requirements Roadmap* (Reliability Roadmap) is the comprehensive framework which contemplates the AESO's broad range of initiatives to address the reliability challenges emerging or expected to emerge as the grid transforms. The Reliability Roadmap is intended to:

- Educate stakeholders on operational challenges that can emerge as Alberta's supply mix transforms due to increasing volumes of inverter-based, variable wind and solar generation, and reduced volumes of dispatchable, synchronized generation and other trends
- Present the results of the AESO's detailed technical analysis and modelling on the current or expected impacts, timing, and degree of urgency for mitigation based on current operational experience and realistic projections of future supply mixes
- Present action plans to mitigate these challenges based on their degree of urgency and impact

As the AIES continues to transform and new information on specific trends impacting the timing or direction of the transformation becomes available, the impacts of these changes will need to be continuously analyzed to ensure current and future reliability implications are understood and mitigated.

Based on the findings in this Reliability Roadmap and future assessments, the AESO will determine the degree to which specifically focused initiatives should be pursued. In some cases, reliability challenges may be identified that require the AESO to take urgent action. The AESO recognizes the importance of promoting awareness and understanding of reliability challenges and offering insights into potential solutions, and directly and effectively engaging stakeholders as appropriate.

Key Findings and Action Plans

The technical studies and system modelling that inform the Reliability Roadmap represent advancements in the AESO's capabilities and corresponding in-depth assessments of specific impacts to Alberta's grid from a transforming supply mix. To fully understand potential impacts on system reliability, the Reliability Roadmap utilizes observed operational data from recent events, enhances and extends prior analysis, and employs scenario-based projections for a decarbonized electricity grid and increasing electrification of the broader economy.

The scenarios used are characterized by significantly higher volumes of renewable energy generation, energy storage, other forms of low-carbon generation and changing load patterns. They allow the AESO to examine a range of plausible future operating states of a transformed grid to identify specific operating challenges, determine when these challenges may emerge and their degree of severity, and identify potential mitigation approaches. Based on this assessment, priorities and action plans aligned to the degree of urgency and required nature of mitigation can be developed.

The specific scenarios used in the robust engineering assessments detailed in the Reliability Roadmap are:

- Years 2026 and 2031 Renewables and Storage Rush Scenario from the 2022 *AESO Net-Zero Emissions Pathways Report* (AESO Net-Zero Report)
- Years 2026 and 2031 Clean-Tech Scenario from the *AESO 2021 Long-Term Outlook* (2021 LTO)

The AESO has previously assessed the reliability consideration of supply adequacy in both the 2021 LTO and the AESO Net-Zero Report. The Net-Zero report recognized the risks to supply adequacy during the net-zero transformation, while also noting that further detailed reliability assessments are required to fully understand the reliability implications of the transformation. The Reliability Roadmap documents the results of reliability assessments in the areas of primary frequency response and system strength, which were identified as needed in the Net-Zero report; and it extends previous supply adequacy assessments by quantifying supply adequacy risks related to unit commitment, while taking the investment decisions represented in the forecast scenarios as given.

The Reliability Roadmap focuses on three key areas of reliability: Frequency Stability, System Strength, and Flexibility Capability. The following sections contain a description of each issue, the degree of mitigation urgency required, key findings from the AESO's reliability assessment and action plans. Areas are presented from highest to lowest urgency for mitigation.

FREQUENCY STABILITY

Frequency stability is the ability of the grid to maintain sufficient frequency and recover to normal operating frequency following the sudden loss of a large supply source. Frequency stability is driven by system inertia and primary frequency response from supply sources and load. System inertia primarily impacts how quickly frequency falls after a contingency, while primary frequency response primarily impacts how far the frequency falls and how quickly the system stabilizes. To ensure the stability of the overall grid and to maintain compliance with reliability standards aimed at protecting the North American grid, the AESO must operate the system such that the Under-frequency Load Shedding (UFLS) protection system, designed to prevent cascading outages due to under-frequency conditions, is not expected to be triggered within system planning criteria. UFLS can be triggered if frequency drops too low immediately following a contingency or does not recover to a high enough level in sufficient time.

Degree Of Urgency

- **HIGH |** The AESO's current highest priority is ensuring sufficient frequency response capability. Existing frequency-related operational challenges mean that immediate action is required to reduce frequency stability risk. The need for mitigation will continue to grow over time as the generation fleet continues to transform

Key Findings

- There is an urgent need to mitigate the risk of UFLS activation due to the sudden loss of a large supply source. Frequency response has been declining due to increasing inverter-based wind and solar generation and decreasing coal or natural gas generation synchronized to the grid
- There is elevated UFLS risk while the AIES is weakly connected or islanded from the rest of the Western Interconnection, even considering the reduced Most Severe Single Contingency (MSSC) limit the AESO currently applies in this circumstance
- Primary frequency response (PFR) is the primary driver impacting frequency stability within the next 10 years. From a frequency stability perspective, system inertia is less concerning compared with PFR in the AIES within the next 10 years, based on AESO's current forecast
- Frequency response is expected to decline further with continued inverter-based wind and solar generation penetration. It is expected that primary frequency response in the AIES will be reduced by approximately 15 MW/-0.1Hz and 20 MW/-0.1Hz in 2026 and 2031 respectively, as compared to 2021. Additional mitigation is required to counteract the declining PFR and to maintain commensurate system performance levels
- System inertia determines the Rate of Change of Frequency (RoCoF) after the supply loss in the frequency response. Furthermore, high RoCoF may unexpectedly trip generation and the RoCoF impact on generation stability is still to be determined in the AIES
- Increases to the MSSC limit or Alberta–British Columbia intertie (B.C. intertie) restoration can require more PFR in the AIES
- A Montana–Alberta Tie Line (MATL) DC conversion can require less PFR for the same level of imports into the AIES

Action Plan

- Urgently implement mitigation measures to lower the current risk of UFLS activation due to supply loss. As an immediate mitigation, the AESO intends to increase the arming levels of Fast Frequency Response (FFR) while importing to reduce the risk of UFLS activation. The AESO is also exploring near-term (2023) procurement of additional FFR services as mitigation when the AIES is operated as a frequency island, or weakly connected and anticipates providing further information in 2023
- Develop a procurement for FFR services to be operational prior to, or by, the beginning of 2025 at the latest
- Continue to evaluate and engage as required with stakeholders to determine the best-fit long-term solutions to address frequency stability to balance mitigation of operational risk with the associated cost of mitigation.
- Continue to study and investigate frequency stability challenges, including the RoCoF and intertie angle stability
- Improve frequency stability situational awareness in real-time operations

SYSTEM STRENGTH

System strength is the ability of the grid to maintain normal voltage at any given location despite disturbances. When the system is stronger at a particular location, it means the voltage at that location undergoes fewer changes when it is subject to active or reactive power injection or consumption. A weaker system has higher sensitivity and hence more voltage variations.

Weak system strength can result in issues with generator controls, fault ride-through or protection systems, impacting the ability of supply to continue delivering to the grid and also reducing power quality.

Synchronous generators (primarily coal and gas-powered in Alberta) that are electrically coupled to the system are the largest contributors to system strength. The predominant Inverter-based Resources (IBRs) equipped with grid-following technologies (primarily wind, solar photovoltaic [PV] and battery storage that are either partially or fully decoupled from the system and rely on system strength at their point of interconnection) do not currently contribute to system strength.

Degree of Urgency

- **Medium |** System strength challenges are generally confined to a small number of local areas and are not currently a system-wide issue. The number of weak system locations is expected to increase in the second half of this decade

Key Findings

- System strength will continue to decline due to increasing penetration by IBRs, with further potential challenges expected towards the latter part of the assessment period (2027-2031)
- Weak areas of the system are expected to be primarily concentrated in southern Alberta where high penetration of IBR wind and solar resources is expected
- The southern terminal of the Eastern Alberta Transmission Line (EATL) and the Grande Prairie region also demonstrate increasing weakness
- Recent system events of voltage oscillation, voltage instability and DER tripping revealed system strength concerns in the Medicine Hat and Stavely areas of the AIES

Action Plan

- The AESO's near-term focus is on improving the existing interconnection requirements of IBRs and updating facility controls to enable additional IBRs to interconnect to the system in weak areas. These changes will also support reliability improvement across the entire transmission system
- Conduct further evaluation of potential longer-term solutions, including market-based solutions, new technologies or infrastructure solutions, to determine feasibility and assess cost, market, operational and regulatory considerations

FLEXIBILITY CAPABILITY

System flexibility refers broadly to the ability of the electric system to adapt to dynamic and changing conditions while maintaining balance between supply and demand. Flexibility capability can be considered within several timeframes including asset commitment (days to hours), ramping capability (hours to minutes), dispatching (hours to minutes), and regulating reserve actions (minutes to seconds).

Degree of Urgency

- **Medium |** Flexibility capability challenges are generally manageable through current forecasting and dispatching practices coupled with regulating reserves. The difficulty in maintaining a balance between supply and demand will become increasingly more difficult year over year with significant challenges in the second half of this decade.

Key Findings

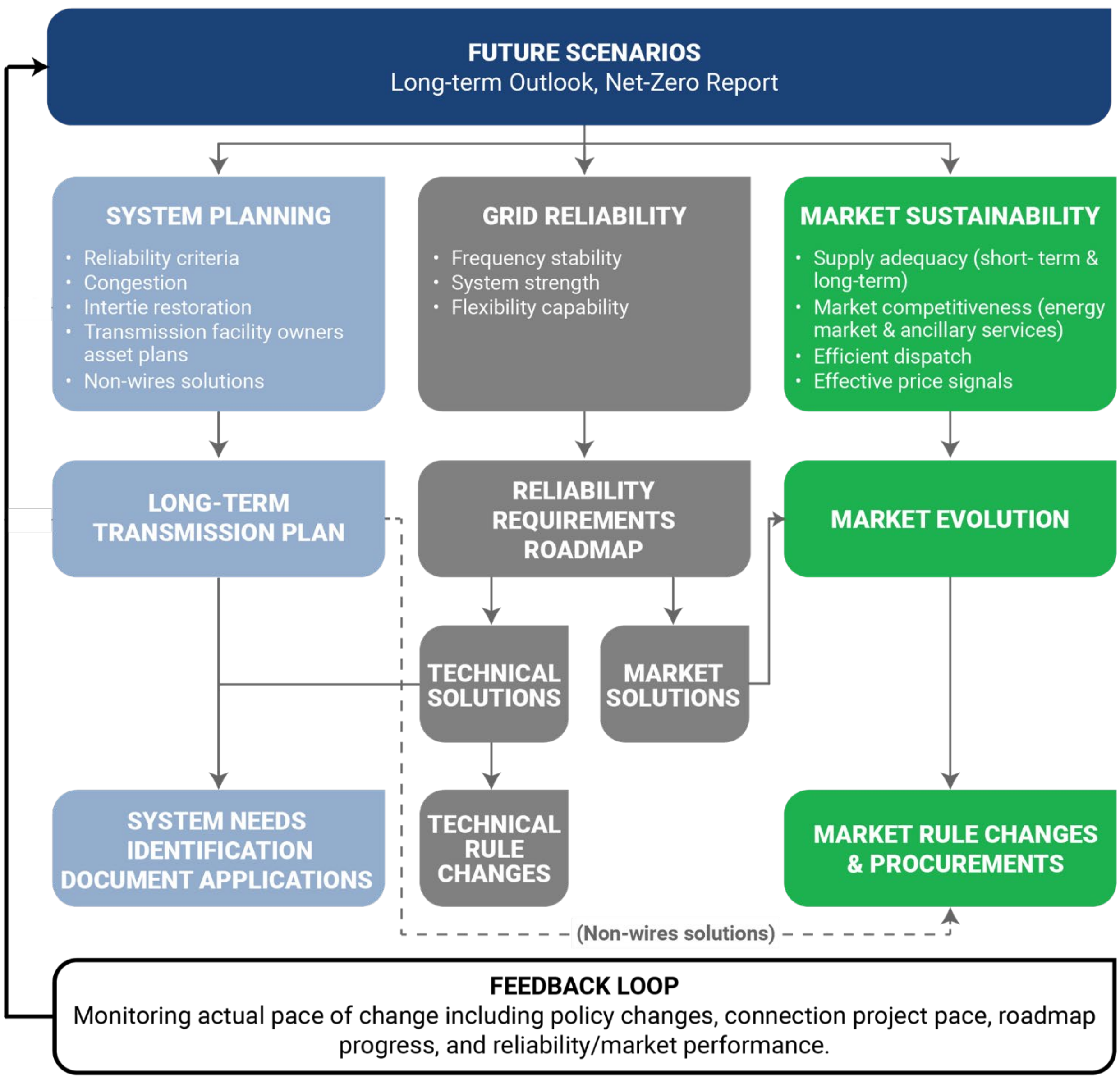
- The variability of wind and solar assets, along with the quality of short-term wind and solar forecasts, can make the real-time balancing of supply and demand challenging
- System flexibility requirements are generally increasing with increased penetration of variable generation, specifically in the last half of the 2020s
- The energy market will experience limited supply cushion and supply surplus more often, increasing the benefit from assets that have more commitment flexibility
- Net-demand changes will become more frequent and larger, increasing the need for system ramping capability
- Greater amounts of energy market dispatch, regulating reserves, and instantaneous interchange will be required to respond to more frequent and larger net-demand changes
- Increased mitigation for system flexibility will be required by the mid-2020s

Action Plan

- Investigate opportunities to improve short-term wind and solar forecasting accuracy
- Improve short-term dispatch modelling sophistication to better reflect operations in a changing electricity environment
- Investigate the increased use of regulating reserves to manage increasing net-demand variability over the next two to five years
- Investigate and progress market design changes to incent greater flexibility within the system in coordination with other market sustainability analysis

Related AESO Initiatives

As Alberta's electricity system continues to transform, it is critically important to ensure that the initiatives identified within the Reliability Roadmap not only remain aligned with one another but also with other key AESO initiatives. As detailed in the diagram below, assessing the operational and market implications of the transforming grid and determining actions to be taken from this assessment is an ongoing and interrelated process.



The AESO has been engaging with stakeholders on a broad range of initiatives to understand and assess how best to integrate new technologies and policy trends while maintaining operational readiness to mitigate reliability risks, including:

- 2019 Energy Storage Roadmap
- 2020 Distributed Energy Resources (DER) Roadmap
- 2021 Long-term Outlook (LTO) and pending 2023 LTO
- 2021 Fast Frequency Response (FFR) Pilot
- 2021 Evaluation of Most Severe Single Contingency (MSSC)
- 2021/2022 Grid Reliability and Operational Preparedness Engagements
- 2022 Net-Zero Emissions Pathways Report
- 2022 System Flexibility Assessment
- 2022 Long-term Transmission Plan (LTP)
- 2022 Request for Information (RFI) – Solutions to Mitigate Instantaneous Impacts of Sudden Supply Loss

The AESO is currently assessing submissions received as part of the *RFI for Solutions to Mitigate Instantaneous Impacts of Sudden Supply Loss*. The objective is to determine potential alternative solutions over multiple time horizons to ensure the system maintains frequency levels and withstands sudden supply loss. Once the evaluation stage is complete, the AESO plans to report on the nature of the solutions proposed, along with next steps. Solutions proposed in the RFI may inform next steps regarding longer-term solutions to mitigate declining frequency stability in the AIES.

The AESO is also currently evaluating submissions received in response to the MSSC Options Paper. The feedback on MSSC options and next steps on this topic are related to required levels of mitigation for frequency response as discussed in greater detail in section 3 Frequency Stability.

As discussed in the 2022 LTP, the AESO is also assessing plans to restore intertie scheduling capability, including B.C. intertie restoration options, and the potential for a back-to-back high-voltage direct-current (HVDC) converter on MATL. These changes, which can also impact the size of contingencies on the system and required level of frequency response, are also discussed in greater detail in section 3.1.4 Reliability Response.

Further, a number of the market-related mitigation options identified in this report will be considered as part of a review of the evolution required in the energy market to support Alberta through the transformation to a decarbonized future. The AESO will begin engaging with stakeholders on this review in the latter half of 2023. It is important to note that while the Reliability Roadmap is focused on ensuring reliable grid operations, this work is being done in parallel with other foundational activities at the AESO. These include:

- Supporting the long-term sustainability of the market
- Advancing modernization of the ISO tariff
- Developing long-term transmission plans that identify current and future needs considering creative lower-cost solutions
- Enhancing the Alberta reliability standards program, among others

Action plans across all broader AESO initiatives will be coordinated and progressed on a prioritized basis. For additional details regarding current AESO initiatives and engagements, please visit AESO Engage » Projects.

2 Background

2.1 Motivation

Alberta's supply mix is changing. Dispatchable (synchronous) coal generators are being retired or re-powered ahead of schedule. Market participants are adding non-dispatchable (wind and solar PV) and inverter-based (wind, solar PV, and battery storage) generation to the grid at a rapid pace. While the province welcomes this investment, the AESO must be prepared for operating challenges associated with these changes to the generation fleet. This Reliability Roadmap has been developed to define new and evolving operating challenges and document the AESO's plans for maintaining system reliability.

2.2 Objective

The Reliability Roadmap identifies system operating challenges that are beginning to manifest and are anticipated to progress over a 10-year horizon. It documents the work the AESO has performed, including engineering studies and in-depth analysis, along with plans to further investigate and address those challenges to ensure the reliable operation of the electric system now and in the future.

This 2023 Reliability Roadmap is focused on operating challenges within the following three reliability domains:

- **Frequency Stability |** Ensure frequency performance is adequate for the system to sustain supply loss contingencies in the AIES or intertie import loss contingencies
- **System Strength |** Ensure system strength is adequate to support the reliable operation of inverter-based resources (e.g., wind, solar PV, and battery storage), either by making the system stronger or improving the performance of IBRs where the system is weak
- **Flexibility Capability |** Ensure the system has adequate balancing capability to respond to the combined variability of load and generation, so the AESO can meet performance targets for regulating interchange

OPERATIONAL READINESS

The AESO is also working to maintain and enhance operational readiness to respond to the reliability risks arising from the growth of variable generation.

Real-time operational challenges have increased due to the rapid pace of renewables generation connecting to the grid, including the appearance of multiple congestion areas that require continuous mitigation. These challenges are currently manifesting in areas of the system with high concentrations of wind and solar resources and typically low load demand, which is causing congestion on the grid. The increased congestion is causing real-time transmission line overloads. Additionally, outage planning, outage management and forced outage response in weaker areas of the system are becoming more complex.

To ensure the continued safe, reliable and economic operation of the transmission system, additional investment will be required for studies, data collection and storage, modelling upgrades and monitoring tools.

2.3 Scope

To fully understand potential impacts on system reliability, the Reliability Roadmap utilizes observed operational data from recent events and enhanced and extended prior analysis, and employed scenario-based projections for a decarbonized electricity grid and the broader economy characterized by significantly higher volumes of renewable energy generation, energy storage, other forms of low-carbon generation and changing load patterns.

Not all system operating challenges are within the scope of the Reliability Roadmap. The AESO periodically studies system limits and produces internal regional operating plans that form the basis for system operating procedures. The Reliability Roadmap is not intended to document system operating limits that arise mainly because of limited transmission capacity. The Long-term Transmission Plan, published biennially by the AESO, documents plans for maintaining the transmission system and increasing capacity where it is needed.

Some specific supply technologies have unique considerations that warrant focused initiatives. The AESO created the *Energy Storage Roadmap* to address challenges related to energy storage technologies. Likewise, the *Distributed Energy Resources Roadmap* was developed to reliably enable the integration of distributed generation (such as distribution-connected generation).

The AESO has previously published periodic assessments of forecasted system flexibility requirements, primarily addressing the impact of increasing renewable resource generation capacity on the electric system. In the future, those System Flexibility Assessments will be replaced by periodic updates of the Reliability Roadmap. System flexibility is an important consideration, along with other reliability topics addressed in the roadmap.

SUSTAINING RELIABILITY

As a leader in enabling the transformation of Alberta’s electricity system, the AESO is working to understand how new and emerging technologies will impact the grid, as well as enhance grid reliability. This includes working with stakeholders to identify promising technologies that have the potential to be incorporated as mitigations to the reliability challenges identified in the Reliability Roadmap.

The AESO is preparing to integrate emerging technologies into the electricity grid through several interrelated initiatives including the Technology Forward publication, DER Roadmap and Energy Storage Roadmap. In the coming months, the AESO will work to ensure all of these initiatives, together with the Reliability Roadmap, reflect a cohesive plan.

When discussing the change of generation and its impact on the electric system, there are two concepts with subtle differences: one is inverter-based resources (IBRs), and the other is non-dispatchable generation (which is also interchangeable with variable generation). For Frequency Stability and System Strength, the focus is on the impact of IBRs. For Flexibility Capability, the focus is on the impact of non-dispatchable generation.

2.4 Scenarios for Assessments

The following scenarios were used as the foundation for load and generation assumptions.

Scenario	Source	Assessment
Base Case	2021 historical data	Frequency Stability | System Strength *provides a reference for the current system state*
Reference Case	2021 LTO	Flexibility Capability *used to evaluate a baseline penetration of renewables generation and energy storage assets*
Clean-Tech	2021 LTO	Frequency Stability | Flexibility Capability *used to evaluate a higher penetration of renewables generation and energy storage assets*
Renewables and Storage Rush	AESO Net-Zero Report	Frequency Stability | System Strength | Flexibility Capability *used to evaluate an* ***even higher*** *penetration of renewables generation and energy storage assets*

As system reliability requirements generally increase as more renewables generation is integrated into the electric system, the Clean-Tech Scenario from the 2021 LTO and the Renewables and Storage Rush Scenario from the AESO Net-Zero Report were selected for further assessment within the Reliability Roadmap, as they included the largest forecasted amounts of renewables generation and distributed energy resources.

The Reference Case, Clean-Tech Scenario, and Renewables and Storage Rush Scenario assessments were prepared for a 10-year forecast period, from 2022 to 2031. The AESO considers the 10-year time horizon adequate to enable proactive identification of potential reliability concerns, with sufficient time for the design and implementation of approaches to address any emerging issues. Limiting the assessment to 10 years also avoids the increased uncertainty that accompanies forecasts over longer timeframes.

REFERENCE CASE

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

In the 2021 LTO's Reference Case, 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 gigawatts (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
- **Renewables 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 renewables generation capacity by 2031

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 *2021 Long-term Outlook*.

CLEAN-TECH SCENARIO

The Clean-Tech Scenario used in this assessment is from the 2021 LTO and 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 remain the predominant generation source in the Clean-Tech Scenario, and oil and gas will remain a significant contributor to Alberta's economy throughout 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 growth in small DERs of less than 5 MW capacity as an offset within the load data, totalling 1.2 GW of DER 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 4.9 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*.

RENEWABLES AND STORAGE RUSH SCENARIO

The Renewables and Storage Rush Scenario used in this assessment is from the AESO Net Zero Report, which assumes that Alberta's electricity system will move towards net-zero emissions through significant capital investments. The Renewables and Storage Rush Scenario considers limited new low-emitting thermal generation, significant amounts of intermittent wind and solar generation, and a large penetration of energy storage development that plays an important role in managing the intermittent generation.

For the AESO Net-Zero Report, the AESO refined the modelling of transportation and DERs of less than 5 MW capacity. Other sectors were added that are expected to grow in an electrified and decarbonized future (building heating systems and new industrial load from hydrogen production). The combined effect of sectoral electrification and growth in DERs is markedly higher than the 2021 LTO scenarios by three to five per cent in 2031. Load growth in this forecast through 2031 is moderate (at 1.0 per cent per year), thanks to gradual increases in EVs and hydrogen production. As well, the AESO Net-Zero Report includes significant small DERs of less than 5 MW capacity as an offset within the load data, totalling 1.3 GW of DER capacity by 2031, of which 1.1 GW is solar generation.

The Renewables and Storage Rush Scenario tests significant penetration of wind and solar generation. Under the Renewables and Storage Rush Scenario, approximately 6.2 GW of new generation capacity is expected to develop by 2031 for a total Alberta capacity of 23.4 GW in 2031. Capacity additions include 4.8 GW of wind, 2.0 GW of solar and 1.4 GW of energy storage assets by 2031. The Renewables and Storage Rush Scenario generation forecast includes capacity additions and retirements for specific generation technologies at levels different from the other scenarios.

More information on the Renewables and Storage Rush Scenario is available in the AESO Net-Zero Report.

LOAD AND GENERATION CAPACITY FORECAST

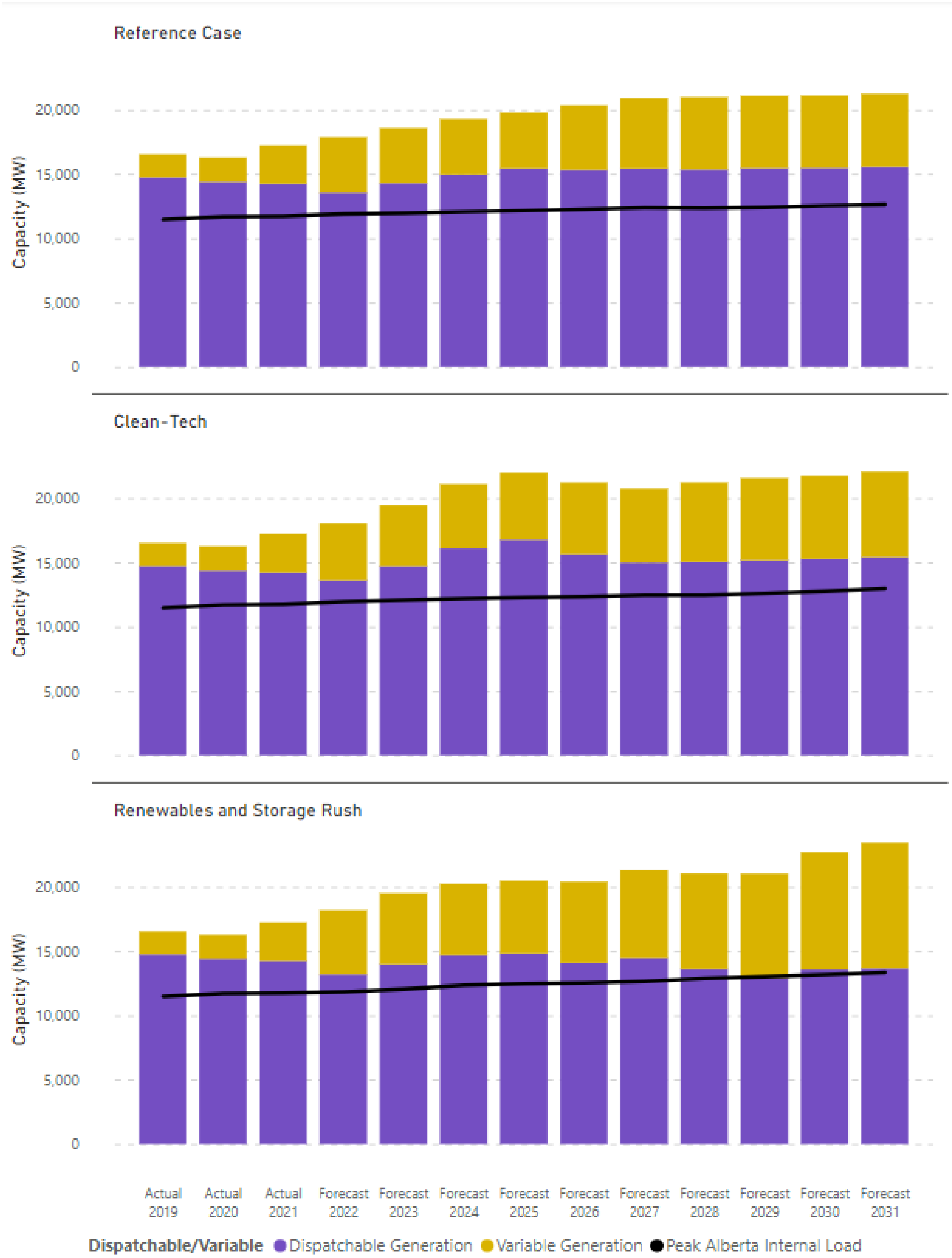
The following Figure 1 illustrates the annual load and generation capacity, differentiated between variable and dispatchable generation for the Reference Case, Clean-Tech Scenario, and Renewables and Storage Rush Scenario. The following generation sources were included in the assessment:

- Coal-fired
- Gas-fired steam (also referred to as coal-to-gas conversions)
- Cogeneration
- Combined cycle
- Simple cycle
- Hydro
- Energy storage
- Variable generation (wind and solar PV)
- Other dispatchable generation

Note: Intertie capacity is not included.

> *The AESO completed numerous engineering studies in each of the three critical reliability domains, analyzing hundreds of thousands of data points focused on three timeframe scenarios: 2021 Historical Scenario, 2021 Reference Case and Clean-Tech Scenario from the 2021 Long-term Outlook, and the 2026 and 2031 Renewables and Storage Rush Scenarios from the 2022 Net-Zero Emissions Pathways Report.*

Figure 1: Peak AIL and generation capacity by scenario



Note: Generation excludes DERs of less than 5 MW.

3 Frequency Stability

3.1 Reliability Issues

Frequency stability is the ability of the electric system to maintain an acceptable frequency level and to recover from supply-demand imbalance due to contingencies in a timely manner. The electric system's ability to respond to contingencies causing system imbalance is heavily impacted by the composition of its generation fleet, the strength of its interconnections with adjacent and regional electric systems, and the breadth and depth of its reliability support services.

This section addresses key challenges that impact transmission system reliability and solutions to maintain frequency stability. Topics include:

- An overview of AESO frequency response obligations
- A review of specific characteristics of frequency stability such as system inertia, RoCoF, and inherent reliability limits
- An overview of supply loss considerations, including specific scenarios
- An overview of frequency response, as well as established and potential new reliability response mechanisms

3.1.1 AESO Obligations for Frequency Response

The AESO is the Balancing Authority (BA) and Reliability Coordinator (RC) in the AIES and, as such, is responsible for the reliable operation of the electric system, including maintaining system frequency at 60 Hertz (Hz), in both normal and abnormal grid operation.

When the AIES is interconnected with the Western Interconnection through alternating current (AC) interties, including the B.C. intertie and the Montana–Alberta Tie Line (MATL), Alberta Reliability Standard (ARS) BAL-003-AB 1-1.1[1] is applicable. This standard obligates the AESO to maintain sufficient frequency response to help maintain Western Interconnection frequency, within predefined bounds, by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value.

Occasionally the AIES may become disconnected from the Western Interconnection. When it is operated as a frequency island, or weakly connected, it is more technically challenging for the AESO to respond to frequency excursions solely with internal frequency response. Poor AIES frequency response may result in UFLS activation, which interrupts the Alberta Internal Load (AIL) in order to rebalance supply and demand and arrest and recover from frequency deviations. The AESO's obligation for frequency stability is discussed in further detail in Appendix A, section 1.1.

*The AIES is interconnected with the Western Interconnection through AC interties with British Columbia and Montana, via 138/500 kV lines and a 230 kV line respectively. A **weak interconnection** means the AIES is interconnected with British Columbia through 138 kV line(s) only, and when the AIES has no electrical connection with the larger system, it is operating as a **frequency island.***

[1] Alberta Reliability Standard (ARS) BAL-003-AB 1-1.1 https://aeso.ca/assets/documents/BAL-003-AB1-1.1-.pdf.

The AESO's ability to ensure real-time frequency stability is heavily dependent on the generation supply mix and load conditions. The higher the proportion of IBRs supplying renewable power and the lower the AIL demand, the more difficult it is for the AIES to provide sufficient frequency response. As such, the electric system's frequency response capability may be less during certain supply scenarios (e.g., high wind and high import) and is therefore expected to decline further with increasing renewables penetration. To maintain system frequency the AESO relies on generation and load response. Should the measures taken by the AESO to arrest frequency deviations not be successful, UFLS will be triggered to support frequency stability. The AESO is working on an action plan to address frequency stability concerns and is prioritizing mitigating challenges arising during AIES disconnection from the Western Interconnection.

3.1.2 Frequency Stability Characteristics

SYSTEM INERTIA

System frequency is proportional to the speed of the rotating machines that are synchronously connected to the electric system. These machines store kinetic energy in their rotating mass, which is referred to as system inertia when aggregated across the electric system.

System inertia is determined by the generation supply mix and acts as a buffer between supply and demand imbalance, where the inertia power response:

- Is autonomous
- Responds in equal proportion to the supply and demand imbalance
- Continues until the balance between supply and demand is restored through other means

The inertia response will not restore the balance between supply and demand, but rather the system inertia will continue to respond until the balance is restored through other means. Typically, the inertia response occurs immediately following the contingency to when PFR and FFR services have restored the imbalance and arrested the frequency, typically within 10 seconds.

RATE OF CHANGE OF FREQUENCY

System inertia also acts to limit the RoCoF, which is the change in frequency between two successive measurements over a defined time interval. The higher the system inertia, the more difficult it is to change the system frequency for a given imbalance, which results in a small RoCoF. Conversely, the lower the system inertia, the easier it is to change the system frequency, which results in a large RoCoF for the same imbalance. In frequency response, RoCoF can determine the lowest point of frequency. For a given time to restore imbalance after the supply loss, the larger RoCoF can result in lower frequency to arrest which may cause frequency stability concerns. This large RoCoF is a clear indicator that the system is short of inertia.

Furthermore, generators may monitor and incorporate RoCoF into their real-time protection schemes because a high RoCoF may cause mechanical damage to the rotating shaft. Generators may also monitor RoCoF to trip the generation to prevent the generators from islanding operation. Overall, high RoCoF may unexpectedly trip generation. Other jurisdictions have determined appropriate RoCoF limits for their systems[2] and to determine an appropriate RoCoF limit applicable to the AIES, the AESO will need to further engage with generating facility owners.

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[2] EirGrid (in Ireland) determined that all the generating facilities in their system can withstand RoCoF at 1 Hz/s and unstable operations were detected when the RoCoF was at 1.5 and 2 Hz/s. An independent analysis on the ability of Generator to ride through Rate of Change of Frequency values up to 2 Hz/s, DNV KEMA Energy & Sustainability, 2013.

RELIABILITY LIMITS OF FREQUENCY STABILITY

System frequency stability is heavily dependent on the ability to deploy sufficient frequency response mechanisms to arrest and recover from frequency changes caused by sudden supply loss. Insufficient frequency response in the AIES can have knock-on impacts such as generator trips, UFLS activation or even AC intertie cascading trips. To better understand how RoCoF, the frequency nadir point (when frequency has reached its minimum), and frequency stabilization impact frequency stability by supply loss and how the supply loss impacts intertie in-rush, please refer to Section 3.1.3.

- Rate of Change of Frequency
  - High RoCoF may cause generators to trip due to the activation of protection settings
  - High RoCoF indicates shortness of (low) system inertia
  - High RoCoF may result in lower frequency nadir point
- Frequency nadir point
  - Low-frequency nadir point may activate the instantaneous tripping block in UFLS
  - Low-frequency nadir point may indicate shortness of inertia or PFR, slow PFR or a combination of each
- Frequency stabilization
  - Sustained low frequency may activate the time-delayed tripping block in UFLS
  - Frequency stabilization at a low point for a long time indicates shortness of PFR
- Intertie in-rush
  - Excessive in-rush flow beyond the in-rush margin on AC interties due to supply loss in the AIES may activate the remedial action scheme (RAS) to trip the interties as a cascading trip
  - The in-rush margin will impact Total Transfer Capability (TTC) on AC interties
  - The anticipated maximum in-rush flow and the in-rush margin on AC interties must be checked and planned for and must be coordinated amongst the B.C. intertie and MATL to manage the impact

3.1.3 Supply Loss Considerations

Supply loss can occur as the result of an unplanned failure of a system component, such as an internal generator or a transmission line, or as the result of import loss from an AC intertie. A supply loss causes an immediate power imbalance between supply and demand in the power system and if significant enough, may cause UFLS activation to arrest frequency decay and restore system frequency. A supply loss in the AIES impacts not only frequency stability but also AC intertie reliability because the in-rush flow may overload and trip the intertie. The AESO thus includes intertie reliability as part of frequency stability assessment.

Additionally, there is an MSSC limit effective in the AIES to manage the anticipated impact of a supply loss on the system to within the reliability limit. As described in the AESO's *Evaluation of MSSC Options Paper*[3], the current MSSC limit is 466 MW when the AIES is interconnected with the Western

[3] Evaluation of Most Severe Single Contingency | AESO Engage.

Interconnection (interconnected MSSC limit) and the MSSC limit is reduced to 425 MW when the AIES is weakly interconnected or islanded with the Western Interconnection (islanded MSSC limit).

SUPPLY LOSS SCENARIOS

The AIES is becoming more susceptible to frequency challenges due to supply loss as Alberta's electric system transitions towards a decarbonized future with renewable resource generation's share of the supply mix increasing and conventional generation's (primarily gas-powered) share of supply mix declining. To better understand potential supply loss impacts on the electric system, the AESO has assessed the four supply loss scenarios described in Figure 2 and is engaging with stakeholders to seek new technology solutions to mitigate frequency deviations through a Request for Information process[4].

Figure 2: Supply loss scenarios

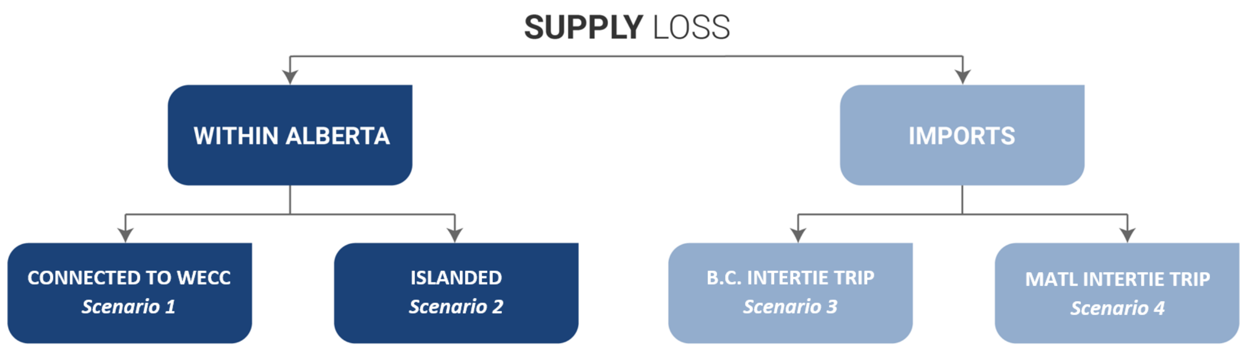

Figure 2: Scenarios 1 and 2 (within Alberta)

Supply loss from a generator while the AIES is interconnected with the Western Interconnection:

- When the Alberta system is connected to the Western Interconnection, as in scenario 1, supply loss from generator(s) in the AIES poses the risk of overloading the AC interties. The reliability risk assessment in this scenario is focused on intertie reliability rather than system frequency stability
- The existing interconnected MSSC limit is 466 MW, which is used to set the anticipated maximum supply loss in a single contingency in the AIES and is also used to calculate the transmission reliability margin on the AC interties to protect against in-rush flow due to supply loss in the AIES

Supply loss from a generator while the AIES is islanded or weakly interconnected:

- The supply and demand imbalance due to supply loss, as in scenario 2, results in the system frequency deviating from 60 Hz
- Depending on the size of the contingency, system inertia and available PFR at the time of supply loss, the frequency deviation could be large enough to activate UFLS
- To reduce the probability of UFLS activation, generator output is currently set to an MSSC limit of 425 MW when the AIES is operating as a frequency island or weakly interconnected with the Western Interconnection

[4] RFI – Solutions to Mitigate the Instantaneous Impacts of Sudden Supply Loss | AESO Engage.

Figure 2: Scenarios 3 and 4 (imports)

Supply loss from import on AC intertie:

- When the B.C. intertie trips, as in scenario 3 of Figure 2 the AESO also disconnects MATL to prevent it from overloading
  - This currently forms a single contingency that manifests as a loss of supply when importing, which poses an increased risk of UFLS activation. Scenario 3 is much like the risk from loss of supply while islanded in scenario 2 of Figure 2
- To reduce the probability of UFLS risk, the AESO could increase the required volumes of FFR to be armed dependent upon system conditions or adverse weather forecasts
- When the MATL intertie trips, as in scenario 4, it poses a risk of overloading the B.C. intertie

UNDER-FREQUENCY LOAD SHEDDING

Under-frequency load shedding (UFLS) is applied to arrest declining frequency and assist in the recovery of frequency following under-frequency events. Usually, UFLS is considered the last resort of system preservation measures and is the automatic action required to shed system load when the system frequency falls below the predefined conditions. ARS PRC-006-AB-3 requires that the AESO adopts and modifies, as appropriate for the AIES, a UFLS program[5] that is coordinated across the Western Electricity Coordinating Council (WECC). Therefore, the AIES UFLS settings[6] largely align with the WECC UFLS program, including both instantaneous and time-delayed tripping blocks.

Instantaneous tripping blocks are mainly used to boost the system frequency from extreme instantaneous low frequency, whereas time-delayed tripping blocks are needed to help the system frequency recover from sustainable low frequency. There are additional AIES security blocks intended to protect Alberta's electric system against the simultaneous loss of an intertie with high import plus large internal supply loss in the AIES. UFLS provides last-resort system preservation measures before additional generation trips due to low frequency. As per Alberta Reliability Standards, the AESO cannot plan to use UFLS to mitigate a frequency excursion[7]. Theoretically, UFLS is anticipated to be activated when the frequency nadir point in frequency response is lower than the trigger condition of instantaneous tripping blocks or the recovering frequency remains below the under-frequency threshold throughout the duration of the time delay period, where both the under-frequency threshold and the time delay are specified by the UFLS time-delayed tripping blocks.

INTERTIE IN-RUSH

If supply loss (contingency) occurs in the AIES when the AIES is interconnected with the Western Interconnection via the AC interties:

- Most of the resulting supply deficit manifests as incremental imports on the AC interties (in-rush power) under normal circumstances
- Depending on the pre-contingency loading on the interties, the interties are not necessarily capable of sustaining the in-rush power demanded by supply loss in the AIES without mitigation

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[5] 2021-002-Alberta-UFLS-Program-2021-12-22.pdf (aeso.ca).

[6] All the UFLS settings in the AIES are defined in Table 1 in ISO Information Document (ID) #2021- 002 Alberta Underfrequency Load Shedding Program in ARS PRC-006-AB-3.

[7] As per ARS TPL-002-AB1-0.

- All interties are physically limited in their capacity to transfer power; exceeding the limit will likely lead to voltage collapse

Based on these considerations, it is necessary to preserve an adequate amount of transfer capability on the AC interties to handle the intertie in-rush and avoid cascading trips of the interties. Otherwise, the import loss on the interties, when added to the supply loss, will result in a severe frequency excursion for which the AIES does not have sufficient frequency response available to avoid UFLS activation.

A detailed explanation of intertie in-rush was provided at the AESO's Sustaining Reliability Through the Transformation stakeholder information session (Transformation Session) in August 2022[8]. The reliability concerns are summarized as follows:

- The capacity required to account for intertie in-rush is based on the interconnected MSSC limit in the AIES. For the given AC intertie capacity required for intertie in-rush, any increase of the interconnected MSSC limit requires mitigation to fully compensate for the incremental intertie in-rush caused by a supply loss in excess of the current interconnected MSSC limit

POWER ANGLE STABILITY

In addition to the intertie in-rush margin, the reliability of an AC intertie is also dependent on the power angle difference between line terminals of the intertie during steady state and intransient. Theoretically, the power angle difference on the B.C. intertie will change should the AESO increase the transfer capability and change the line impedance of the intertie via the Alberta Intertie Restoration (AIR) project and the Chapel Rock to Pincher Creek (CRPC) transmission development project.

The AESO has verified that for both projects, the power angle in a steady state will not exceed 90 degrees and cause instability after supply loss in the AIES. Hypothetically, if the AESO has a higher interconnected MSSC limit and a supply loss in the AIES matches this new limit, there may be a risk that the power angle difference on the B.C. intertie may exceed 90 degrees momentarily before mitigation response is deployed to offset the excessive inadvertent in-rush, which would trip the intertie. The assessment of power angle stability is not included in this report and the AESO plans to further assess AC intertie power angle stability with regard to future transmission development.

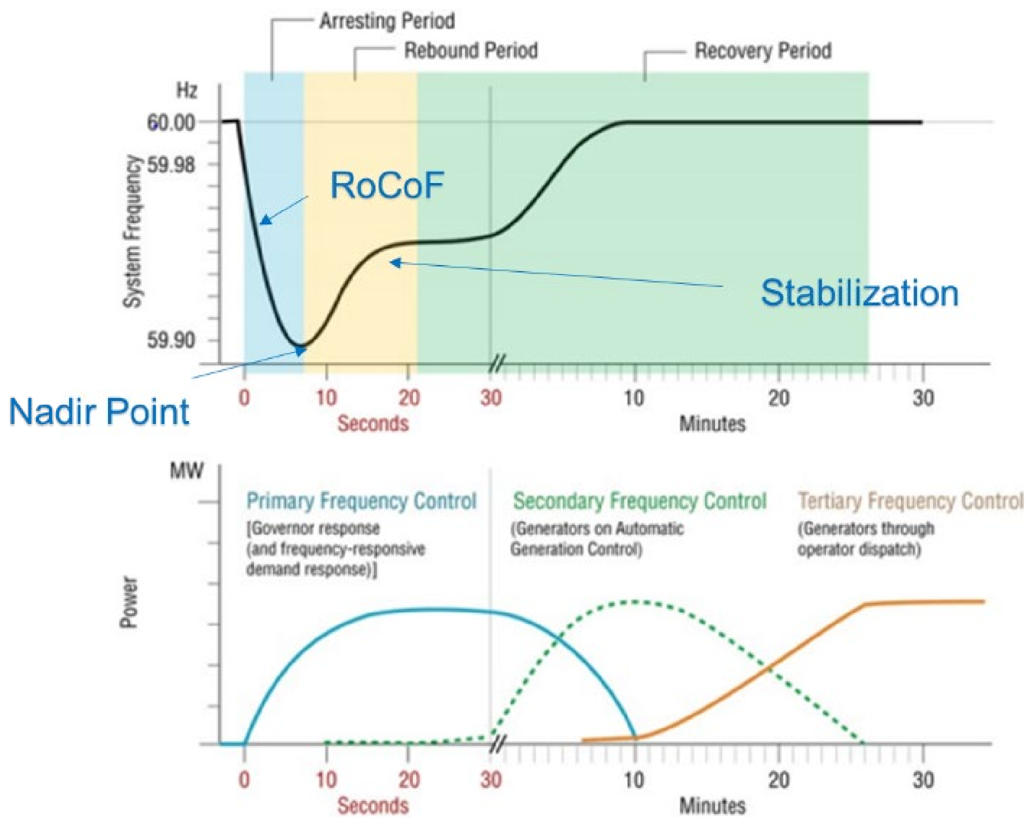
[8] https://www.aesoengage.aeso.ca/sustaining-reliability-through-the-transformation.

3.1.4 Reliability Response

FREQUENCY RESPONSE OVERVIEW

During normal operating conditions, the system frequency will deviate from 60 Hz (i.e., nominal frequency) when supply and demand are not balanced. The typical frequency response to a supply loss is illustrated in Figure 3.

Figure 3: Typical frequency response



- During the frequency arresting period, when an imbalance between supply and demand occurs, the system frequency initially changes by the RoCoF, which is based on the size of the imbalance and the system inertia
- As the frequency deviates from 60 Hz, PFR responds by changing its real power to minimize the power imbalance, which reduces the RoCoF
- When the PFR has mitigated the power imbalance, the RoCoF is zero, the frequency has reached its minimum (nadir point) and the frequency excursion has been arrested
- After the frequency is arrested, the generators with remaining PFR capacity continue to respond to previous primary frequency response actions where supply continues to increase and frequency rebounds. After the rebound, the frequency settles at a low value for a period of time. In this report, it is also called *frequency stabilization*
- Frequency recovery occurs as secondary frequency control (i.e., regulating reserve via AGC control) and tertiary frequency control (i.e., contingency reserve) are deployed

PRIMARY FREQUENCY RESPONSE

The North American Electric Reliability Corporation (NERC) defines PFR as “The immediate proportional increase or decrease in real power output provided by generating units/generating facilities and the natural real power dampening response provided by load in response to system frequency deviations. This response is in the direction that stabilizes frequency.”[9] PFR acts to stabilize system frequency following a disturbance causing an under- or over-frequency excursion, and also acts as a buffer to supply-demand imbalance. PFR is typically controlled by a generator’s governor which responds in the form of a change in electrical output proportional to the ongoing frequency deviation and continues until frequency is within the deadband. The response occurs within the first few seconds after a frequency excursion and continues until frequency has been fully restored with the help of regulating reserve and contingency reserves. In contrast, inertia is provided from kinetic energy stored in the rotating mass of a generator, and inertia response is proportional to the RoCoF.

SECONDARY FREQUENCY RESPONSE

Secondary frequency response consists of regulating reserves which are responsive to automatic generation control (AGC) which monitors balancing attributes including the system frequency and import levels. This service is typically provided within one minute of the contingency event.

TERTIARY FREQUENCY RESPONSE

Tertiary frequency response is provided by:

- Contingency reserves such as spinning reserves that are immediately and automatically responsive to frequency deviations through the action of a governor or other control system
- Supplemental reserves, which are either generation capable of being connected to the AIES within 10 minutes, or load that is connected to the AIES that can be reduced within 10 minutes
- Generation that can be dispatched from the energy market merit order

FAST FREQUENCY RESPONSE

Fast Frequency Response (FFR) is frequency response used to help arrest and stabilize under-frequency excursions and responds significantly faster than primary frequency response (response time measured in thousandths of seconds). When the measured system frequency (in Hertz) drops below a predefined threshold value, FFR is designed to respond rapidly to release additional power to reduce power imbalance and the response volume, either load reduction or power increase, is independent of ongoing frequency deviation. Currently, the AESO has contracted with both energy storage (currently FFR Pilot) and load (currently Load Shed Service for imports [LSSi]) service providers to provide FFR. FFR is armed by the AESO’s System Controllers based on a pre-determined LSSi/FFR Arming Table[10] and the service provider must provide the required response for one hour, or unless notified by AESO’s System Controllers.

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[9] NERC Reliability Standards Glossary of Terms (updated March 29, 2022). https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

[10] Table 7(a) and 7(b) in ID #2011-001R of Section 303.1 of ISO rules (https://www.aeso.ca/assets/Information-Documents/2011-001R-ATC-and-Transfer-Path-Management.pdf).

The deployment of FFR:

- Lowers the RoCoF
- Raises the nadir point of the frequency
- Provides more time for PFR to deploy
- Raises the stabilized frequency in the event of supply loss

FAST NET DEMAND RESPONSE

The AESO is assessing a potential new service (Fast Net Demand Response or FNDR) to improve intertie reliability due to a large internal supply loss. FNDR is a potential event-based protection scheme designed to automatically respond quickly to reduce demand or increase supply. The trigger events would include large supply loss contingencies that create excessive inadvertent flows on the AC interties. For example, a large supply loss can occur because of a large generator trip or transmission line contingency. FNDR could be used to offset the inadvertent flow increase on the AC interties beyond the in-rush margin, which otherwise could cause the AC interties to trip. Theoretically, one MW of excessive inadvertent in-rush flow over the intertie in-rush margin can be offset by one MW of FNDR, subject to being able to withstand the transient conditions (power angle stability) described in section 3.1.3 Supply Loss Considerations.

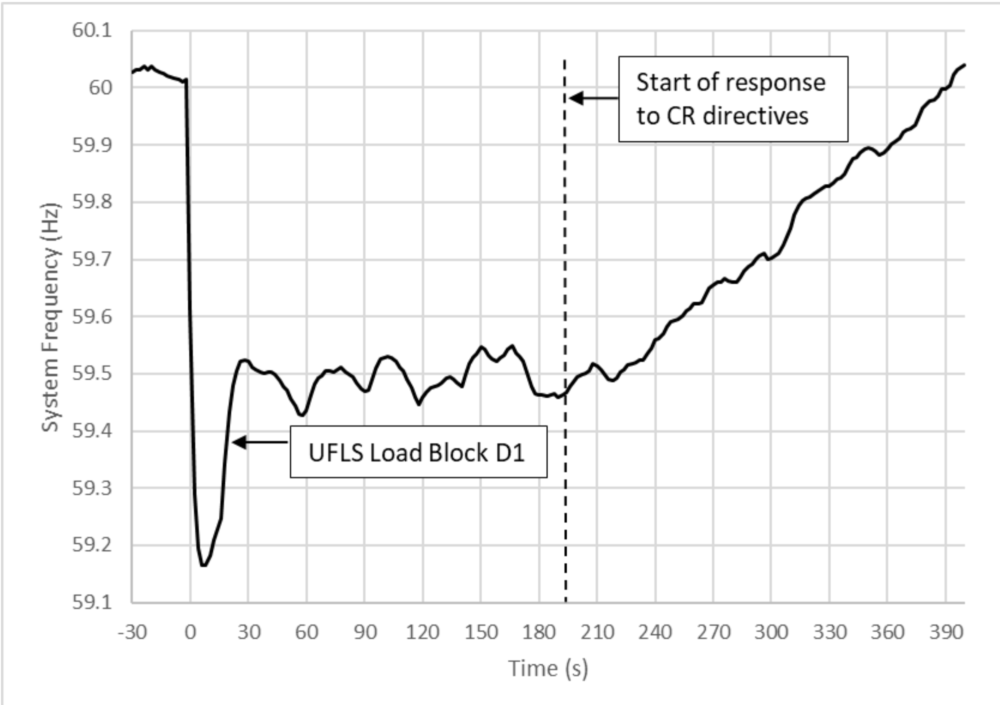
The primary purpose of FNDR is to protect AC interties from tripping by offsetting excessive inadvertent in-rush flows. Because this service is activated by the breaker status of key generating units instead of system frequency monitoring, the time to deploy it is faster than FFR. Therefore, the deployment of FNDR can potentially reduce the required volumes of FFR. Theoretically, FNDR can be used for frequency stability as well; however, there is a drawback given that a tie-line trip doesn’t necessarily mean the AIES will be exposed to a frequency stability issue. FNDR deployment by the intertie status and before the frequency drops may cause an overshoot on the frequency response and may trigger an over-frequency issue.

Fast Net Demand Response is effective at mitigating intertie in-rush when a significant generator supply loss occurs. 1 MW of FNDR can offset 1 MW of intertie in-rush flow and may enable a potential Most Severe Single Contingency level increase in the future.

FREQUENCY RESPONSE IN ALBERTA

If the AIES experiences supply loss due to either a large generator tripping when the system is operating as a frequency island, or due to the sudden loss of the B.C. intertie when importing while interconnected with the Western Interconnection, it will cause significant frequency decay and could result in the activation of UFLS. This is shown in the following Figure 4, which demonstrates a frequency response in the AIES after a real-time supply loss event that triggers UFLS.

Figure 4: Frequency Response in the AIES in event of scenario 3



In this example (refer to Figure 2: Supply loss scenarios) the AIES was experiencing high wind generation, low AIL and significant imports when a lightning strike caused the sudden loss of the AC interties.

- The sudden loss of the AC interties with import caused the AIES to be a frequency island with significant frequency deviation from 60 Hz
- The inertia response determined the RoCoF for the given size of power imbalance at the beginning of this event
- Primary Frequency Response started its response to the deviation by changing its real power output to minimize the power imbalance
- Frequency decay continued and once frequency dropped to 59.5 Hz, the armed FFR volumes were tripped to reduce power imbalance and help arrest the frequency
- Primary Frequency Response continued to reduce power imbalance and mitigated the power imbalance at a frequency nadir point of 59.15 HZ and frequency started to rebound
- Sustained low frequency activated the UFLS-delayed trip blocks which worked with PFR to enable the system to recover and frequency to stabilize between 59.43 Hz and 59.55 Hz for approximately 3 minutes (frequency stabilization period)
- Frequency recovery occurred as regulating reserves (via Automatic Generation Control [AGC]) and contingency reserves (directed by the AESO’s System Controllers) were deployed and the frequency was gradually restored to 60 Hz
- In this example, the frequency nadir point was not sufficiently low enough to activate the instantaneous UFLS trip block
- The inertia response continues as long as the frequency fluctuates through the event

3.2 Operational Experience

The capability of the AESO to arrest frequency decay without activating UFLS is being impacted by Alberta's changing generation supply mix and its inherent inertia and primary frequency response capabilities. Due to insufficient primary frequency response capabilities, UFLS was activated several times in 2020 and 2021. These UFLS activation events were triggered by the tripping of generation in Alberta while operating in islanded mode and/or tripping of the interties while interconnected with the Western Interconnection.[11]

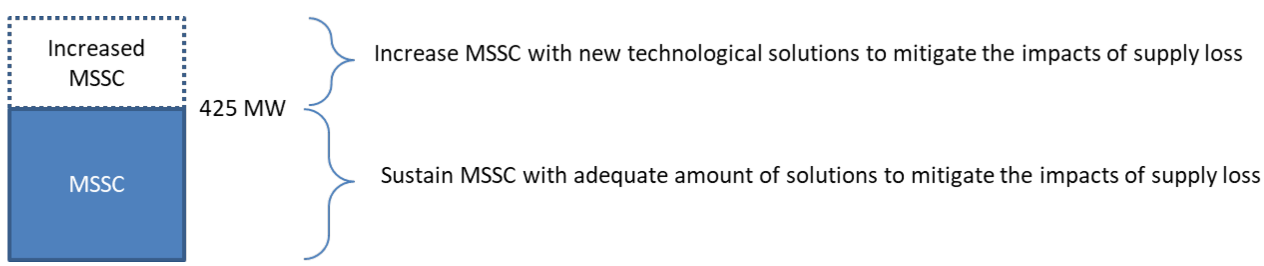
As discussed in the previous sections, system frequency stability is determined by the frequency response capability of the system as well as the RoCoF and UFLS settings. Frequency stability determines the largest supply loss that the system can withstand without activating UFLS, which can impact the MSSC limit. The MSSC limit, in turn, determines the in-rush margins on the AC interties, hence influencing the maximum level of imports. A supply loss resulting from an intertie trip also significantly impacts system frequency. The AESO manages this risk by procuring FFR and contingency reserves and limiting available transfer capability (ATC) on the AC interties based on FFR availability. Currently, the AESO has several initiatives related to frequency stability, MSSC limit, and intertie restoration, including:

- Request for Information: Solutions to Mitigate the Instantaneous Impacts of Sudden Supply Loss[12]
- Evaluation of MSSC Options Paper: Published to engage stakeholders and address MSSC limits[13]
- 2022 LTP: System projects | AIR and CRPC Transmission Development to increase TTC on the B.C. intertie and potential MATL back-to-back converter[14]

These initiatives are all interrelated and therefore need to be considered and assessed together to determine the best approach to ensure system frequency stability. The following Figure 5, Figure 6 and Figure 7 illustrate how all initiatives are interrelated in various scenarios.

Figure 5 depicts a frequency island scenario in which the islanded MSSC limit is determined based on frequency stability, in that a supply loss will not activate UFLS. A potential increase to the islanded MSSC limit will require mitigation to ensure frequency stability.

Figure 5: Mitigating impacts of supply loss on MSSC level when the AIES is islanded



[11] For further details on these events refer to Grid Reliability and Operational Preparedness > AESO.

[12] https://www.aesoengage.aeso.ca/rfi-solutions-to-mitigate-the-instantaneous-impacts-of-sudden-supply-loss.

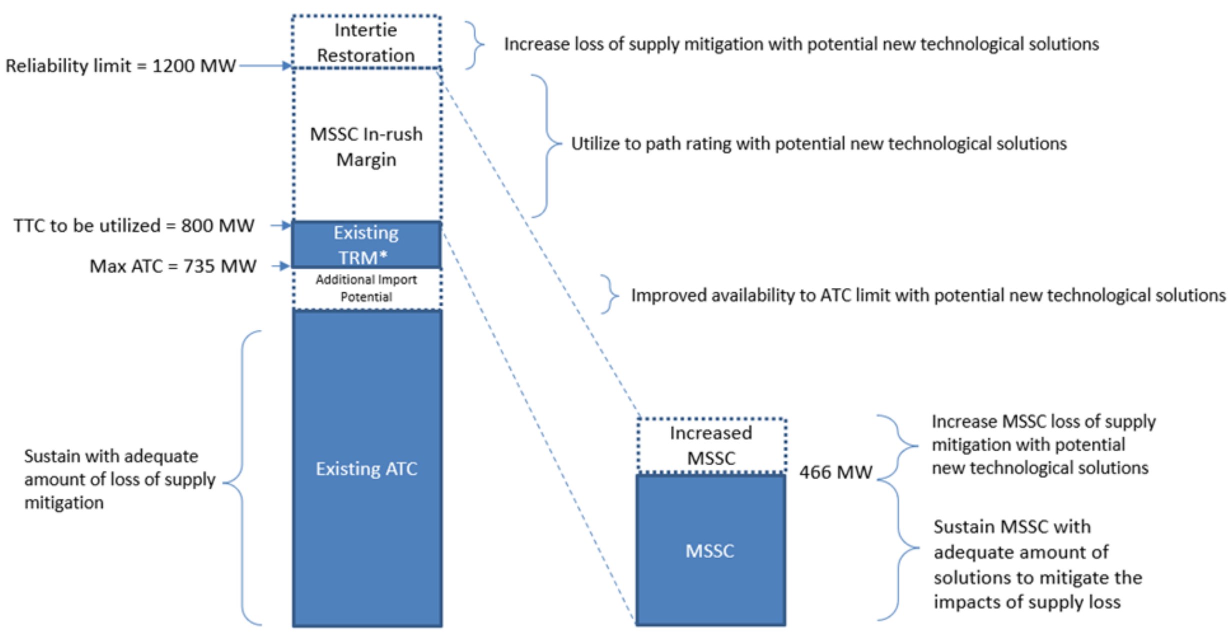
[13] Evaluation of Most Severe Single Contingency | AESO Engage.

[14] https://www.aeso.ca/assets/Uploads/grid/ltp/AESO-2022-Long-term-Transmission-Plan.pdf.

Figure 6 depicts the interconnected scenario when the MATL intertie is out of service or if a back-to-back HVDC converter is added to separate the dependency with the B.C. intertie. The MSSC limit indicates the maximum supply loss in the AIES or the maximum net supply loss due to a B.C. intertie trip. In the event of a supply loss in the AIES, the AESO needs to maintain sufficient transfer capacity for the in-rush margin on the B.C. intertie to handle the intertie in-rush flow or have a mitigation to offset the excessive in-rush flow. Otherwise, the total flow on the intertie may exceed the reliability limit, causing the B.C. intertie to trip by RAS.

On the other hand, if the scenario is import loss, AIES frequency stability is of the highest concern after the intertie is tripped and mitigation of frequency decay is required. At present, the AESO uses FFR as the mitigation solution to ensure frequency stability as per Section 303.1 of the ISO Rules[15]. Any MSSC limit increase or intertie transfer capability increase will result in a change in the required amount of mitigation.

Figure 6: Loss of supply intertie (MATL out-of-service)

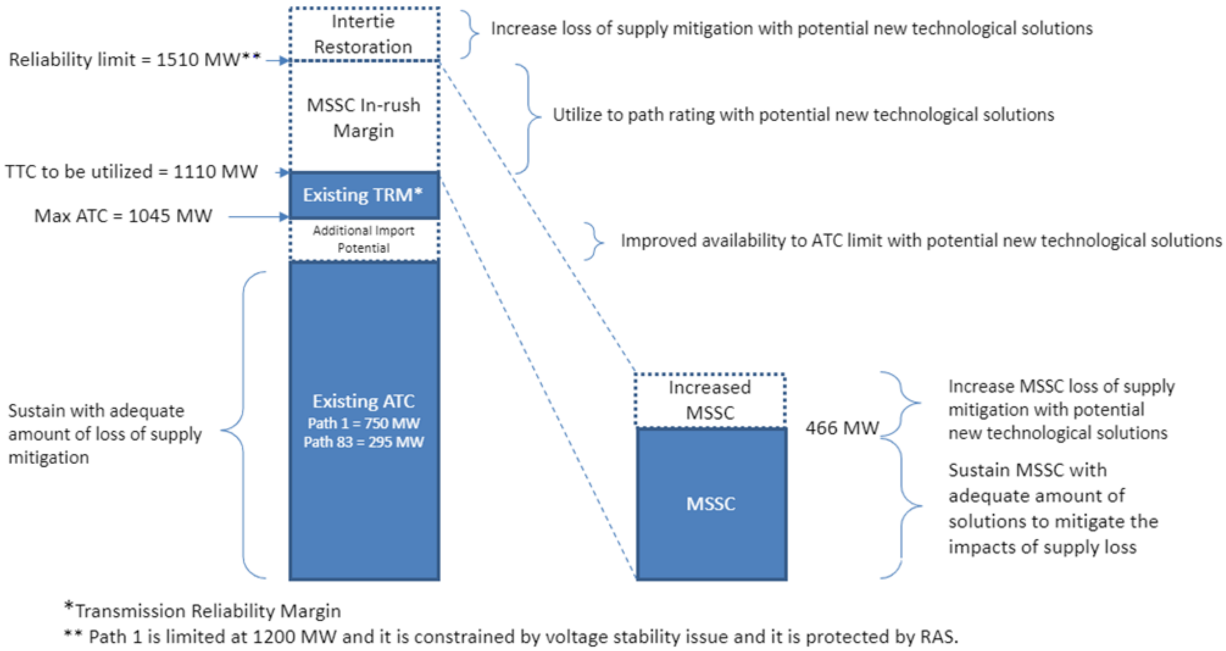


*Transmission Reliability Margin

Figure 7 depicts the interconnected scenario when both the B.C. intertie and MATL are AC interties and in service. Similarly, with Figure 6, the MSSC limit will impact the mitigation to offset in-rush flow after a supply loss in the AIES and also the mitigation to frequency decay after import loss.

[15] https://www.aeso.ca/assets/documents/Division-303-Section-303.1-Load-Shed-Service-July-1-2013.pdf.

Figure 7: Loss of supply intertie (MATL and B.C. intertie both in-service and operating as AC interties)



3.3 Frequency Stability Assessment

3.3.1 Study Objectives and Process

To better understand both immediate and longer-term frequency stability impacts to the AIES, the AESO initiated a technical assessment to:

- Confirm the root cause for UFLS activation
- Better understand the severity of frequency stability challenges
- Validate the effectiveness of potential mitigation solutions
- Determine how these frequency stability challenges impact the AESO's ability to deliver on other priority initiatives
- Improve risk-based decision making

The focus of this assessment is on inertia and PFR since UFLS activation occurs during the timeframe of PFR. Potential opportunities for improvement in Secondary Frequency Control are included in the Flexibility Assessment section in this Reliability Roadmap. Tertiary Frequency Control is likewise an aspect of system flexibility. Opportunities for improving contingency reserve products will be assessed as part of the AESO's market sustainability review.

The assessment results can be used to determine the criticality and magnitude of the challenges across the different time horizons (2021, 2026 and 2031) as well as the effectiveness of the mitigation solutions (FFR for frequency stability and FNDR for intertie reliability and/or frequency stability) to resolve the challenges. The study results can then be used to more effectively engage with stakeholders to execute the identified action plans to ensure frequency stability.

Given the importance of maintaining frequency stability without activating UFLS, focusing on inertia and PFR was a critical measure when determining the system's capability to manage frequency response.

3.3.2 Results

Upon completion of the assessment for all studied scenarios, the results revealed that Alberta's changing generation supply mix is significantly impacting the AESO's ability to manage frequency stability and avoid UFLS in both the immediate term and over the longer term, given that IBRs do not provide frequency response in the same way as conventional generators. The assessment also provided insights into the effectiveness of potential mitigation solutions (of which FFR and FNDR are described further below) as well as how the frequency stability challenges might impact the AESO's ability to deliver other priority initiatives.

The key findings from the frequency stability assessment are summarized as follows:

- There is an urgent need to mitigate the risk of UFLS activation due to the sudden loss of a large supply source. Frequency response has been declining due to increasing inverter-based wind and solar generation and decreasing coal or natural gas generation synchronized to the grid
- There is an elevated UFLS risk while the AIES is weakly connected or islanded from the rest of the Western Interconnection, even considering the reduced MSSC limit the AESO currently applies in this circumstance
- Primary frequency response (PFR) is the primary driver impacting frequency stability within the next 10 years. System inertia is less concerning compared with PFR in the AIES within the next 10 years based on AESO's current forecast
- Frequency response is expected to decline further with continued inverter-based wind and solar generation penetration. It is expected that primary frequency response in the AIES will be reduced by approximately 15 MW/-0.1Hz and 20 MW/-0.1Hz in 2026 and 2031 respectively, as compared to 2021. Additional mitigation is required to counteract the declining PFR and to maintain commensurate system performance levels
- High RoCoF beyond 1 Hz/s due to a large supply loss was observed in the 2026 study results; the AESO will engage with GFOs to determine current settings and perform an additional assessment to determine appropriate mitigation
- FFR is effective in mitigating risk of UFLS activation; confidence in mitigating UFLS activation increases when additional FFR is deployed
- MSSC limit increase will increase FFR and FNDR requirements
  - An additional 1 MW increase of the islanded MSSC limit will require an additional 1 MW of FFR to achieve the same confidence
  - An additional 1 MW increase of the interconnected MSSC limit will require an additional 1 MW of FNDR to achieve the same confidence
    - An additional 1 MW increase of interconnected MSSC limit resulting in higher in-rush flow exceeding preserved in-rush margin on Alberta–B.C. intertie will require an additional 1 MW of FNDR for intertie reliability
    - FNDR can also effectively improve frequency stability. 1 MW of FNDR can be used as 1 MW of FFR for frequency stability based on the settings used in the assessment. Due to its proposed triggering mechanism, FNDR is also faster than FFR and can potentially be used to reduce RoCoF

- Alberta-B.C. intertie restoration will increase FFR requirements
  - Import ATC increase on the B.C. intertie via the AIR project will require an additional 200 MW of FFR to achieve the same confidence
  - Import ATC increase on the B.C. intertie via the CRPC project (after the AIR project) will require an additional 200 MW of FFR to achieve the same confidence
- A MATL back-to-back converter (direct current [DC] converter) could reduce the required FFR by up to 300 MW for the same level of total imports to the AIES

EFFECTIVENESS OF MITIGATION ACTIVITIES

To better understand the mitigation capabilities of potential solutions the AESO modelled the impacts of distinct mitigation options in three study years (2021, 2026 and 2031). These results are broken into two groups:

- **FFR |** Frequency stability modelled using only FFR as the mitigating solution to evaluate the effectiveness of FFR to mitigate frequency stability. Refer to Appendix A, section 1.4 for additional information on assessment results with FFR
- **FNDR |** Frequency stability modelled using only FNDR as the mitigating solution to evaluate how FNDR impacts frequency stability when it is primarily used to mitigate excessive in-rush flow on AC interties. Refer to Appendix A, section 1.4 for additional information on assessment results with FNDR

IMPACT ON FREQUENCY RESPONSE BY INITIATIVES

In addition to studying the existing electric system, the AESO also modelled system frequency stability impacts from changes to the MSSC limit and AC intertie ATC, including the risk of UFLS activation and intertie reliability. The study scenarios included in the assessment (as shown in Table 6 of Appendix A, section 1.2) will help the AESO understand how strategic initiative decisions will impact frequency stability, and what incremental frequency stability will be required to support these initiatives.

The availability and cost of such mitigation solutions to frequency stability and intertie reliability are important factors in determining the future direction of related initiatives, including:

- Sustaining the current MSSC level
- Evaluating potential MSSC level increases
- Enabling improved utilization of the existing interties
- Evaluating options to restore the B.C. intertie to its path rating

The AESO used the year 2021 as the base case and the existing LSSi/FFR Arming Table to determine the frequency stability service required today. Scenarios are further categorized into two groups, depending on whether MATL is an AC intertie or whether it is a DC intertie. Each initiative, or combination, was assessed against the existing system to identify incremental mitigation required with an assumption that the in-rush margin remains the same.

The focus of this assessment was to better understand the incremental reliability support services (FFR for frequency stability and FNDR for intertie reliability) required to mitigate the additional reliability risk created by implementing the initiatives.

KEY FINDINGS

- Increasing either the islanded MSSC limit or the interconnected MSSC limit above 466 MW will require FNDR on a 1:1 MW basis for an MSSC limit increase
- Increasing intertie ATC above 1,045 MW (MATL AC connected) or above 735 MW (MATL DC connected) will require FFR on a 1:1 MW basis for a B.C. intertie ATC increase

3.4 Potential Mitigations

With frequency stability being an existing operational challenge, and a 10-year forecast projecting further declining system inertia and primary frequency response from an IBR-dominated renewable generation fleet, ensuring sufficient frequency response capability is currently the AESO's highest priority.

To address the immediate concerns by the end of Q1 2023, the AESO will increase the required arming levels in the LSSi/FFR Arming Table to reduce the probability of UFLS being triggered due to the sudden unexpected loss of the AC interties.

The AESO is also currently investigating additional FFR service options in the near term, including frequency stability support when the AIES is operating as a frequency island or weakly connected to the Western Interconnection as well as the launch of a broader FFR procurement in 2024. Additionally, the AESO is assessing submissions received as part of the *RFI for Solutions to Mitigate Instantaneous Impacts of Sudden Supply Loss* to determine potential alternative solutions over multiple implementation time horizons to ensure the system maintains frequency levels and withstands sudden supply loss without activating UFLS. To address inadvertent flow on the interties, the AESO will also further assess FNDR's capability to automatically and quickly reduce demand or increase supply in response to a large supply loss.

In addition to the identified mitigation actions underway, the AESO has identified other possible solutions to address reliability challenges including:

- Lowering MSSC limit
- Installing sync condenser
- Implementing synthetic inertia
- Installing grid-forming technology
- Requiring wider ride-through range
- Specifying PFR performance
- Procuring additional FFR services when required
- Implementing fast-ramp product
- Implementing FNDR procurement
- Market design changes relating to unit commitment

For further information on possible mitigation solutions, refer to Appendix A, section 1.5.

3.5 Operational Readiness

The AESO experienced UFLS activation due to sudden supply loss several times in 2020 and 2021. Three industry engagement sessions were hosted (July 28, 2020, March 9, 2021, and October 7, 2021)[16] where the AESO reviewed the details of each event. The AESO initially shared its three-year action plan to improve frequency response with stakeholders at the October 7, 2021, session. Completed actions from the 2021 Action Plan are summarized in Table 1. These actions demonstrate the AESO's efforts to improve frequency stability. With the detailed assessment of frequency stability completed as part of this Roadmap, new tasks have been identified. They are outlined in the action plan in section 3.6.

Table 1: 2021 Action Plan | Operation experience and readiness for frequency stability

Frequency Control	Category	Action Completed Since 2021
Primary Control	Inertia	• Use real-time system inertia and severe weather near the Alberta–B.C. intertie when determining allowable interchange • Use system inertia as a third parameter to develop arming tables for FFR
	Fast Frequency Response (FFR)	• Work with current LSSi, an FFR product, to improve compliance when system events occur • Pilot project for FFR to enable participation of new technologies such as ESRs
	Primary Frequency Response (PFR)	• Analyze the impact of generator characteristics, ambient temperature, and lack of headroom on system performance • Work collaboratively with Generation Facility Owners (GFOs) to help improve PFR from their assets • Continue collaborative approach with GFOs including ensuring outer control loops and AGC controls do not impede PFR from generators • Modify AESO modelling and operating assumptions
Secondary Control	Automatic Generation Control (AGC)	• Analyze the contribution of resources on AGC during system events • Work with GFOs to ensure AGC controls do not impede the natural frequency response of generators • Enable AGC blocking during system events to ensure recovery and grid reliability
Tertiary Control	Contingency Reserve (CR)	• Analyze the performance impact of CR resources during system events • Work with GFOs to help improve the performance of CR resources during system events
	Net Demand Variability (NDV)	• Optimize the volume of regulating reserves • Provide System Controllers with daily forecast and ramp event reports to support decision making

[16] Grid Reliability and Operational Preparedness » AESO.

3.6 Action Plan

The high-level action plan, as shown in the following Table 2, provides a guideline on how frequency stability will be addressed based on the progress that has been achieved, the priority ranking of the solution, and the implementation timeframe. All the actions have been categorized into four main streams for clarity:

- Implementation of urgent plan
- Completion of unfinished studies and assessments
- Improvement of situational awareness of frequency stability
- Consultation on Long-term solutions

Table 2: Frequency stability action plan

Implementation Time Horizon: *Near-term is <1 year | Short-term is 1-2 years | Mid-term is 2-5 years | Long-term is 5-10 years*

<table>
<tr><th>Priority</th><th>Category</th><th>Action</th><th>Time Horizon</th></tr>
<tr><td rowspan="5">Critical</td><td rowspan="2">Completion of Unfinished Studies and Assessments</td><td>Industry survey on RoCoF settings and limit</td><td rowspan="2">Near-term</td></tr>
<tr><td>LSSi/FFR Arming Table review and revision</td></tr>
<tr><td rowspan="3">Implementation of Urgent Plan</td><td>FFR procurement while islanded</td><td rowspan="3">Near-term</td></tr>
<tr><td>FFR procurement (2025 service term, or earlier)</td></tr>
<tr><td>Additional FFR procurement(s), as required</td></tr>
<tr><td rowspan="7">High</td><td rowspan="3">Completion of Unfinished Studies and Assessments</td><td>Angle stability check on AC intertie due to in-rush</td><td rowspan="3">Near-term</td></tr>
<tr><td>BAL-003 frequency regulating requirement capability</td></tr>
<tr><td>FNDR service assessment</td></tr>
<tr><td rowspan="3">Consultation on Long-term Solutions</td><td>RFI response evaluation</td><td rowspan="2">Near-term</td></tr>
<tr><td>MSSC options paper response evaluation and recommendation</td></tr>
<tr><td>Continuous engagement with industry on long-term solutions</td><td>Short-term</td></tr>
<tr><td>Improvement of Situational Awareness of Frequency Stability</td><td>Development of real-time monitoring tool on PFR</td><td>Near-term</td></tr>
<tr><td rowspan="3">Medium</td><td rowspan="2">Improvement of Situational Awareness of Frequency Stability</td><td>Investigation of EMS dynamic frequency bias</td><td rowspan="2">Short-term</td></tr>
<tr><td>Frequency response obligation monitoring</td></tr>
<tr><td>Consultation on Long-term Solutions</td><td>Implementation of long-term solution

Investigate market-based solutions for frequency performance, which may include a fast ramp product, must-run contracts (for inertia), adjusted OR volumes, pay-for-performance PFR, and other options</td><td>Mid-term</td></tr>
</table>

3.6.1 Implementation of Urgent Plan

The AESO is implementing mitigation measures to lower the current risk of UFLS activation due to supply loss. As an immediate mitigation, the AESO intends to increase the arming levels of FFR while importing to reduce the risk of UFLS activation and is also exploring near-term (2023) procurement of additional FFR services to support frequency stability while operating as a frequency island or weakly connected to the Western Interconnection.

Frequency stability challenges arising from the shortage of PFR response within the AIES is creating significant urgency to identify solutions and implement mitigation plans. To address these challenges immediately, and over the next one to two years, the AESO is undertaking the following actions:

- Increase the arming levels of FFR while importing to reduce the risk of UFLS activation
- Explore near-term procurement of additional FFR services
- Develop a technology-agnostic FFR services procurement to support supply loss when the AIES is interconnected to the Western Interconnection or is operating as a frequency island. Service is to be operational prior to, or by, the beginning of 2025 at the latest

3.6.2 Completion of Unfinished Studies and Assessments

Conducting an industry survey of generating facilities to confirm what RoCoF limit should be used is a priority, followed by confirmation of whether the AIES is, or will be, short of system inertia.

The angle stability verification on the AC interties is also an important task to confirm if the in-rush flow after supply loss will cause transient stability concerns, which FNDR may not be able to effectively mitigate.

3.6.3 Improvement of Situation Awareness of Frequency Stability

Improving situation awareness of real-time frequency stability will be highly beneficial and requires the implementation of new monitoring tools to augment existing monitoring capability. The AESO will also closely monitor frequency response to ensure AIES compliance with our obligation.

The AESO has identified several high-priority tasks to help Real-time Operations to deal with frequency stability challenges; these tasks are less dependent on the selection of preferred solutions.

REAL-TIME MONITORING OF PFR

To provide greater situational awareness, additional tools and procedures may be required to manage emergent operational challenges driven by increasing renewables penetration. A real-time PFR assessment tool is being developed that will work in conjunction with the existing inertia assessment tool to provide a real-time indication as to whether there is sufficient online PFR and inertia to support the current Alberta import schedule. The next step in improving situational awareness could be to develop a forward-looking or forecast PFR and inertia tool that could be used in the future-hour Alberta import capability postings. A real-time inertia and PFR monitoring tool is likely to provide the most accurate assessment of the system’s capability to manage frequency stability.

DYNAMIC FREQUENCY BIAS

As explained in Appendix A, section 1.1, frequency bias should indicate the average frequency response in the AIES. However, the frequency response varies with different system conditions. For example, many synchronous generators may go offline in a high-wind scenario, which reduces frequency response in the

AIES. Dynamic frequency bias rather than a static value can better match the actual frequency response throughout the day and using accurate frequency bias can also improve AGC performance.

FFR ARMING TABLE REVISION

Fast frequency response is used to mitigate impacts on frequency stability when the AIES is interconnected. LSSi is the existing load-responsive FFR service and the FFR Pilot is the existing battery energy storage system (BESS)-responsive fast frequency response. The amount of LSSi and FFR Pilot volumes to be armed for different levels of import is determined based on AIL and the existence of any severe weather forecasts for the B.C. interties transmission corridor and is set based on the confidence of avoiding UFLS activation should the intertie trip. Given the system inertia and PFR reductions in the AIES, a UFLS risk assessment can be included as part of standard operating review processes, and the FFR arming table updated to reflect these conditions.

3.6.4 Consultation on Long-term Solutions

The AESO will continue to engage with industry to determine best-fit, long-term solutions to address frequency stability balance mitigation of operational risk with the attendant cost of mitigation, including evaluating the responses submitted to the *Solutions to Mitigate the Instantaneous Impacts of Sudden Supply Loss* RFI that were deemed to have a longer time horizon.

3.7 Contingency

The Reliability Roadmap assessment clearly highlights the operational challenges to ensuring frequency stability, and demonstrates that additional fast frequency response will be required to offset declining frequency response over the 10-year assessment horizon and maintain confidence in avoiding UFLS activation. To maintain this confidence the AESO will continue to monitor frequency stability performance over the medium and longer term. Additional updates to the LSSi/FFR Arming Table levels may be required to ensure frequency stability and manage the risk of UFLS activation. Should the AESO be unable to procure the required incremental FFR volumes cost-effectively, it will be required to explore contingency plans such as reducing system ATC for imports without offsetting the reductions using incremental FFR.

4 System Strength

System strength is a measure of the power system's ability to preserve its stability under all reasonably credible and possible operating conditions. When the system is stronger at a particular location, it means the voltage at that location undergoes fewer changes when it is subject to active or reactive power injection or consumption. Conversely, a weaker system indicates a higher sensitivity and hence more voltage variations. In this context, system strength refers to the sensitivity of the variations in voltage (magnitude and/or angle) at a specified location in the power system in response to disturbances driven by:

- Load and generation variations
- Faults
- Switching of equipment

In this system stability domain, the AESO will provide an overview of system strength characteristics, identify key challenges impacting transmission system reliability, and discuss solutions to maintain system strength in weaker areas to enable additional variable generation from renewables.

Power system strength is proportional to the available fault current (also known as short-circuit current and is the maximum current available should there be a short circuit) at a specified location. The short-circuit level measures the ability of the electric system to maintain stable voltages and reliably detect and isolate faults at a particular location following a disturbance such as a lightning strike, adverse weather conditions or equipment failure. A high short-circuit level indicates the electric system might be better able to operate in a stable and reliable manner under different operating conditions. Therefore, short-circuit level is a good indicator of the system's ability to reliably respond to any disturbances or large power-flow excursions that may occur.

Presently, system strength at a given location in the power system is predominantly determined by two factors:

- The number of synchronous generators (SGs) or synchronous condensers (SCs) connected nearby
- The number and impedance of transmission lines or distribution lines (or both) connecting the SGs to the rest of the system

System strength is inherently provided by SGs owing to their physical coupling to the system and stabilization of voltage as a by-product of their power generation. Similarly, synchronous condensers not only provide inertia and dynamic reactive power to support transmission system voltage during events, but they are also a source of system strength since they are electro-magnetically coupled to the system. In contrast, IBRs have different characteristics, are fully or partially decoupled from the system by a power-electronics interface, and require a minimum system strength to operate reliably. IBRs effectively act as a sink for system strength.

The AESO is in the early stages of assessing and managing low system strength challenges and is working with industry to adapt to these changing operating conditions. Improving system strength enhances efficiency, resiliency, and security.

Wind turbines, solar photovoltaic inverters and battery energy storage inverters are typically asynchronously connected to the grid and either partially or completely interfaced through power electronic inverters. For this reason, non-synchronous generators are also referred to as Inverter-Based Resources (IBRs)

There is a risk to generators of being forced offline where the system is weak, which impacts grid reliability (see examples in section 4.2). Generation forced offline for reliability reasons has adverse operational consequences and is economically inefficient due to impacts on generation owners and consumers. Through planning and process enhancements, the AESO can manage system strength issues to minimize strength-related constraints and achieve net improvements in economic efficiency.

In the context of the electric system, resiliency means the ability to withstand and recover from improbable events, and security means the correct operation of protection and control systems to transition between stable operating states, respecting equipment limitations.

Some specific threats to reliability, resiliency and security are discussed as follows.

4.1 Reliability Issues in Weak Systems

Historically, system strength has not been a significant concern for the AIES given the inherent strength contributed by the significant number of SGs connected to the system. However, the increasing penetration of IBRs (solar, wind, and BESS) coupled with the displacement of SGs is causing system strength to decline given the differing characteristics of IBRs. Without adequate mitigation measures in place, system strength is expected to continue declining given changing dynamics and performance characteristics of the power system, driven by the transformation of the generation fleet.

The AESO anticipates that system strength shortfalls will emerge in some areas of the AIES and might cause operating challenges that may compromise grid reliability. By assessing system strength across Alberta's grid using various scenarios, the AESO is well-positioned to take action to maintain the secure, reliable, and safe operation of the future power system.

System strength is critical to a secure power system. If the strength of the system is compromised, several relatively complex reliability issues[17] could materialize. The majority of these issues are predominately tied to the performance and interoperability of IBRs, as a vast majority of these facilities largely rely on the strength of the point of interconnection (POI) in the power system. Reliability issues in weak systems include:

- Voltage stability
- Control interactions and instability
- Fault ride-through capability
- Power quality
- Power system protection security

4.1.1 Voltage Stability

System strength shortfall caused by the relatively lower number of online SGs drives lower short-circuit current availability, as well as lower voltage control capability in the system. This shortfall could lead to voltage stability concerns, given the higher sensitivity of voltage variation relative to changes in real or reactive power, in the power system that might place the system at a higher risk of voltage collapse or voltage instability.

[17] NERC Reliability Guideline, "Integrating Inverter-Based Resources into Low Short Circuit Strength Systems," December 2017

Dynamic voltage control and its ability to recover from the reactive power imbalance during and after a large disturbance (e.g., a transmission line fault) is an area of concern. The primary sources of this control are the:

- Inherent response from SGs and SCs
- Voltage sensitivity of demand
- Automatic Voltage Regulators (AVRs) of SGs, IBRs, and Flexible Alternating Current Transmission System (FACTS)

One of the most substantial sources of dynamic voltage control is the inherent response from SGs. The loss of dynamic voltage control capability due to the displacement of conventional generation by higher levels of renewables might decrease response capability and/ or voltage stability margins within specific areas of the system. The differing characteristics of IBRs, as compared to SGs, including increased output variability when coupled with load profiles can significantly impact voltage stability in weak areas of the system.

In the AIES, IBRs connected to the distribution system (DERs) are required to operate in constant power factor control mode to comply with distribution facility owner (DFO) interconnection requirements. In weak areas of the system with reactive power control deficiency, the operation of DERs in power factor control mode makes it challenging to maintain voltage within an acceptable range which may lead to abrupt degradation in system voltage for increased load or power transfers. This degradation reduces the voltage stability margin and, if significant enough, increases the likelihood of voltage collapse.

In contrast, as per the requirements set out in ISO rule 502.1, IBRs connected to the transmission system are required to operate in voltage control mode, which minimizes the risk of voltage collapse.

4.1.2 Control Interactions and Instability

In weak areas of the power system, the potential for disruptive control interactions amongst IBRs, as well as the interactions of IBRs with other power electronic-based devices (e.g., flexible alternating current [AC] transmission system) or conventional generation, is more prominent. In addition, the risk of IBR control instability in weak areas of the system is higher due to the vulnerability of control stability to low system strength at their POI. These interactions or instabilities may result in growing or erratic oscillations that negatively impact overall system reliability[18].

The connection of new IBRs near existing IBRs could degrade the performance of the existing resource, even though the overall fault-current contribution from the IBR resources would increase. This is because while asynchronous generation (e.g., IBR) contributes positively to the total fault level, it effectively acts as a sink for system strength. Therefore, the weaker the system becomes, the higher the risk of interaction among nearby IBRs.

4.1.3 Fault Ride-through Capability

One of the challenges concerning the integration of IBRs into weak areas of the power system is the ride-through capability of these devices during abnormal system conditions when it is subject to voltage and frequency excursions. Reducing system strength margins impacting resilience makes recovery from

[18] Voltage oscillations at low frequencies (e.g., sub-synchronous frequencies) triggered by IBR controls in weak grids have been recently observed in multiple power systems

disturbances (e.g., faults) more difficult. It might also become more difficult to meet other generator performance requirements in weak areas with these new resources, especially where multiple IBRs are connecting nearby.

The higher sensitivity of voltage to current variations in a weak system creates more challenges for the performance of IBR controls. If the associated controls are not properly tuned and coordinated for these abnormal system conditions, unwanted tripping of the IBR may result and consequently exacerbate voltage and frequency excursions, further degrading system reliability.

Constraints on the ability to interconnect additional renewable resources in weak areas of the system are increasing due to the absence of:

- An operational mechanism to maintain system strength above the minimum secure level[19]
- A mechanism to enable the timely planning for the provision of system strength capability

4.1.4 Protection of Power System

Synchronous generators have predictable fault-current characteristics due to the physics and inertia of rotating machines, and Alberta's transmission line protection systems were designed and optimized for these fault characteristics. IBRs' differing fault-current characteristics present challenges to these protection systems as their characteristics are often weaker and inconsistent (e.g., sequence-current values, voltage-current angles, frequency, magnitude) as compared to SG characteristics, depending on programming and operating modes. These programming and operating modes are continuously evolving to support line protection system performance as technology and grid code requirements improve.

Protection elements impacted by IBRs include the determination of fault direction (forward/backward), selection of fault type (e.g., single line-to-ground, line-to-line, three-phase fault), and impedance measurements (overreach or underreach). Therefore, system strength shortfall might lead to challenges in the reliable detection and clearing of faults by the existing protection schemes.

In summary, a future power system with a higher share of IBRs connected to weaker parts of the system, coupled with a lower share of conventional generators online, can potentially have important ramifications on the protection system's ability to maintain the stability of the power system and prevent equipment damage, unless mitigated.

4.1.5 Power Quality

Power quality can be broadly defined as a measure of how well the voltage, frequency and (voltage/current) waveforms in a power system conform to nominal specifications. Synchronous generators provide significant support to power quality due to their ability to alter their voltage output quickly in response to a system event, as well as acting as a sink for harmonics.

Transitioning toward a grid with a higher share of IBRs creates potential power quality issues, as power electronic devices are used to interface IBRs with the power system. These devices can draw or produce

[19] "Minimum secure level" refers to maintaining minimum short-circuit levels across the AIES that ensures safe and reliable operation of the system during all possible operating conditions, from steady-state and following disturbances. This will be achieved through performing a series of planning and operation studies to identify the minimum levels of short circuit levels that pose the system to minimum risk from reliability and security perspective for all the possible operating conditions.

non-sinusoidal currents that can interact with power system impedance and contribute to harmonic voltage distortion issues.

If not addressed in a timely manner, the increasing use of power electronic devices has the potential to adversely impact power quality, and consequently compromise the reliability of the power system. System strength plays an important role in mitigating the severity of power quality issues. The weaker the system becomes, the possibility of electrical resonances occurring at lower harmonic orders increases which, in turn, amplifies the risk of encountering:

- Unacceptable voltages/currents
- Rapid voltage changes
- Flicker
- Harmonic distortion
- Equipment damage
- Protection malfunction

4.2 Operational Experience

The integration of IBRs across the AIES has led to unforeseen operational challenges, predominantly tied to the operating conditions in the areas with the highest renewables penetration. System forensic and post-disturbance analysis revealed the important role of system strength in contributing to these recent operational events. The following is the summary of the events:

Date	Event	Area	Trigger
July 2021	Solar facility voltage oscillation	Stavely	Low system strength condition following a planned outage
July 2022	Wind farm voltage instability	Medicine Hat	Low system strength condition following a planned outage
June 2021	Solar facility DER interruption	Vauxhall	Low system strength condition following capacitor bank switching

More details about each event's description, impacts, and mitigation actions are provided in Appendix B.

Since August 2016, there have also been multiple major events within the NERC region, where transmission system faults led to the loss of substantial IBR generation.

Following is a summary of some of these events[20]:

Date	Event	Area	Trigger
August 2016	1,200 MW fault-induced PV solar interruption	California	Blue Cut wildfire
October 2017	900 MW fault-induced PV solar interruption	California	Canyon II wildfire
April 2018	877 MW fault-induced PV solar interruption	California	Angeles Forest disturbance
July 2020	205 MW and 1,000 MW fault-induced PV solar interruption	California	San Fernando disturbance
March 2022	765 MW and 457 MW fault-induced wind interruption	Texas	Panhandle wind disturbance
June 2022	1,711 MW fault-induced PV solar interruption	Texas	Odessa 2 disturbance

The extensive investigations led by a NERC IBR task force identified the critical role that IBR control and protection systems play and determined these to be the primary root cause of these supply-loss events. Changes to the control and protection systems post-event effectively mitigated the risk of re-occurrence for many of these operational events. Although the occurrence of these events is not necessarily driven by system strength shortfalls, it highlights the severity of adverse system impacts driven by the lack of, and the need for, unified comprehensive performance and capability requirements for IBRs.

4.3 System Strength Assessment

4.3.1 Study Objectives

The AESO conducted an assessment to identify the areas of the AIES that are subject to system strength shortfall based on:

- Existing conditions
- Scenario-based outlook over the next 10 years

The results of this analysis are intended to determine current challenges as well as indicate likely future challenges across the AIES. Short-circuit levels (SCLs) are a measure of how strong the system is at a particular location with respect to disturbances (e.g., load changes, equipment switching, and faults) and can be used as a screening measure to quantify the strength of the system. In this screening assessment, the AESO used an industry-accepted and commonly applied metric known as Weighted Short Circuit Ratio (WSCR) which considers the SCL, size of connecting IBR, and the impacts of the nearby IBRs at the connecting location to calculate the relative strength of the system. The details of the screening methodology and assumptions for the assessment can be found in Appendix B, section 1.2.

[20] https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx

4.3.2 Results

Upon completion of the assessment for all studied scenarios, the results revealed that areas of the AIES subject to higher penetration of renewables generation might be subject to system strength shortfall, resulting in potential reliability issues. Although not a broader electrical system issue currently, additional interconnection of IBR-based facilities in these weaker areas could further impact existing system strength challenges with more significant impacts expected towards the latter half of the decade.

The assessment also provided insight into potential mitigation solutions, as described in section 4.4 and further in Appendix B, section 1.3, to enable additional IBRs to interconnect to the system in weak areas and support reliability improvements across the wider electrical system.

The key findings from the system strength assessment are summarized as follows:

- System strength will continue to decline due to increasing penetration by IBRs, with further potential challenges expected towards the latter part of the assessment period (2027-2031)
- Weak areas of the system are expected to be primarily concentrated in southern Alberta where high penetration of IBR wind and solar resources is expected
- The southern terminal of the EATL and the Grande Prairie region also demonstrate increasing weakness
- Recent system events of voltage oscillation, voltage instability and DER tripping revealed system strength concerns in the Medicine Hat and Stavely areas of the AIES

The description of each IBR group and its calculated system strength in each study scenario is presented in the following table.

Table 3: Areas in AIES with low system strength outlook

WSCR < 3 represents "weak system" *3 < = WSCR < 5 represents "moderate strong system"*

WSCR > = 5 represents "strong system"

AIES Planning Area	IBR Group Description	Calculated System Strength (WSCR)		
		Studied Scenario		
		2021	2026	2031
4	240 kV path (CBW)-251S to 244S	3.2	1.9	1.6
20	142 kV in area 20	5.7	3	1.4
43	Hanna 142 kV Loop-804S to 946S	7.2	4.3	2.6
47	EATL-South Terminal	3.9	2.4	2.3
49	Stavely 240 kV path-370S to 356S	7.1	2.5	2.3
49	Stavely 138 kV path-15S to 504S	4.9	2.8	1.4
52	Vauxhall 138 kV path-83S to 158S	23.9	3.3	2.3
53	Windy Flats 138S – 138 kV system	2.5*	3.6	2.2

**2021 is included to show trends across AIES Planning Areas only and therefore Planning Area 53 is not highlighted as an area that requires immediate attention. Additionally, upcoming system configuration changes in this area will alleviate the low system strength concern by 2026.*

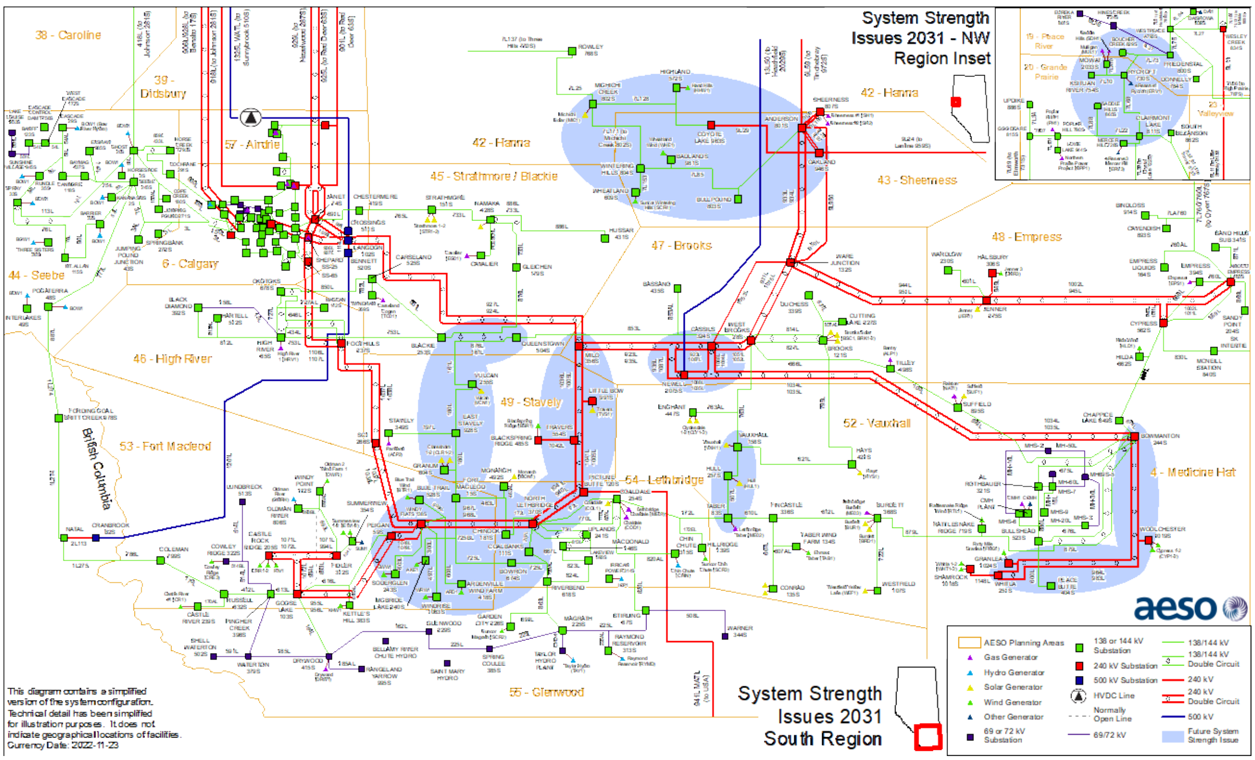
As shown in Table 3, Planning Areas 4 (Medicine Hat) in the southeast and 49 (Stavely) in the southwest require closer attention as the expected levels are anticipated to decline below a threshold of 3 based on study findings. Given that Planning Area 20 (Grande Prairie) is not geographically favourable for wind or solar generation, the same level of concern with regard to the impacts of increasing IBR penetration does not apply. The study findings are aligned with the occurrence of recent oscillation events under planned transmission outage conditions in the same areas.

In addition, the system strength assessment shows a declining trend at the EATL southern terminal at Newell 2075S. This declining trend indicates a weak condition that adversely impacts the operation of EATL, which uses line commutated converter (LCC) technology that relies on a minimum system strength (typically higher than 3) for reliable operation.

Further detailed investigation is required in the identified areas to ensure the stability of the system is maintained under various credible system operating conditions.

Areas of concern are shown on a geographical map in the following Figure 8.

Figure 8: System strength areas of concern



4.4 Potential Mitigations

To overcome the reliability challenges tied to system strength shortfalls it is crucial to explore and identify effective mitigation solutions for maintaining minimum system strength requirements. Mitigation measures will need to be undertaken to support grid reliability and enable additional renewables generation in resource-rich areas of the province.

Potential solutions to address weak power system conditions can address the following:

- Solutions that resolve weak conditions from occurring entirely
- Solutions that enable integration of IBRs in the weak areas of the power system

The AESO will determine a mitigation solution and minimize reliability risks by considering system characteristics, as well as the capabilities of the connecting IBRs.

> *Effective coordination and communication among stakeholders, including transmission facility owners (TFOs), DFOs, manufacturers, GFOs and the AESO are essential to identify the preferred solution to address weak power system conditions.*

Potential solutions to mitigate the reliability risks triggered by weak power-system conditions currently include:

- Wires-based solutions
  - Synchronous condenser
  - Transmission system reinforcement
  - FACTS devices
- Rule-based solutions
  - Reduction in plant capacity or power output
  - Grid-forming inverters
  - IBR plant control system changes
  - Converter control changes
- Market-based solutions
  - Incentive structures for SGs to be online

4.5 Operational Readiness

This section details how the declining trend in the system strength across the AIES as identified in the screening assessment might impact operations.

- **Situational Awareness Enhancement |** The Operations Planning regional area studies are utilized to inform real-time operations. The potential reliability concerns tied to low system strength are not as readily visible in real-time operations as thermal constraints. To maintain situational awareness and reliable operations these additional real-time tools are required:
  - Online Transient Security Assessment Tool (TSAT)
  - Real-time Oscillation Detection
- **Real-time Data Capture |** Operations Coordination is currently developing an in-house tool that allows for the rapid collection of the real-time data needed for transient studies in the Power System Simulator for Engineering (PSS®E). To evaluate future system strength, a process will need to be developed and integrated into weekly operation studies

4.6 Action Plans

The Reliability Roadmap assessment forecasts AIES system strength over the coming decade. Based on projected conditions, the changing generation supply mix, in tandem with decreasing minimum-demand projections driven by emerging DERs, will expose certain areas of the system to higher reliability risks associated with system strength shortfall. In response, the AESO has developed a series of timely actions to enable a seamless transition and preserve the secure and reliable operation of the future power system.

The actions range from improving the AESO's existing IBR interconnection requirements to adopting new technologies and/or market-based solutions to minimize system reliability risks driven by forecasted declining system strength across the AIES. The following proposed actions and potential mitigations are consistent with, and largely reflect the content of the latest industry practices and international guidelines, as well as Alberta's transmission system reliability requirements. The following shows a summary of the proposed actions along with associated urgency; further details for supporting the action plan recommendations to address system strength challenges are included in Appendix B.

Due to the pace of grid transformation, many of the reliability issues associated with high IBR penetration are currently being discovered in the real-time domain, which highlights the urgency of implementing appropriate corrective actions.

The Priority Rank (urgency) and Implementation Time Horizon assigned to each recommended Action reflect the risks and relative cost implications using the latest available information. The AESO is closely monitoring and assessing the changes on an ongoing basis, and Actions will be revised if deemed necessary.

Table 4: System strength action plan

Implementation Time Horizon: *Short-term is < 2 years | Mid-term is 2-5 years | Long-term is 5-10 years*

Priority Rank: *High (H) | Medium (M) | Low (L)*

Priority	Category	Action	Time Horizon
High	Further Analysis and Mitigation Investigation in Identified Weak Areas	• Perform detailed Electromagnetic Transient Simulation (EMT) studies in weak areas of AIES • Investigate whether market-based or wires-based solutions for improving system strength are warranted in areas where IBRs are unable to meet the enhanced requirements	Short-term
	ISO-facilitated Coordination of Controls in Identified Weak Areas	• Confirm that re-tuning of controls can be adopted to alleviate the observed reliability issues • Facilitate a coordinated collaboration with all involved stakeholders to re-tune existing plant controls in the weak areas of AIES	Short-term
	Modelling	• Establish mandatory requirements for GFOs to provide validated phasor domain and EMT IBR models	Short-term
	Interconnection, Planning, and Operation Studies	• Include a SCR-based screening assessment in interconnection studies to identify the risk of reliability issues tied to system strength shortfall while connecting IBRs	Short-term

Priority	Category	Action	Time Horizon
	Tools and Procedures for Real-time Operation	• Establish network and system monitoring to enhance visibility to real-time instability and power system security • Conduct regular system inertia and system strength studies to identify potential upcoming real-time operation concerns to mitigate in a timely manner	Short-term
		• Integrate EMT studies into assessments	Mid-term
	Interconnection, Planning, and Operation Studies	• Augment SCR-based screening with a detailed EMT simulation in areas prone to system strength shortfall to further evaluate reliability risks and failure modes • Work with facility owners and IBR manufacturers to ensure facilities are studied and performance is verified for all credible system conditions	Mid-term
	Process Enhancements	• Develop an integrated generator interconnection and long-term transmission planning process	Mid-term
Medium	Tools and Procedures for Real-time Operation	• Build real-time and forward-looking stability, adequacy, and risk assessment tools for situational awareness and proactive decision-making with the ability to detect oscillations and to forecast system conditions	Mid-term
	Modelling	• Supplement study models with post-commissioning disturbance monitoring to further improve the quality of the model and capture ongoing adjustment of model parameters over the lifetime of the equipment • Implement a feedback loop from real-time operations to ensure model accuracy • Improve the modelling process to clearly articulate study types and requisite supporting (e.g., dynamic, steady-state, short-circuit, and EMT) model requirements as applicable	Mid-term
	Protection System Requirements	• Work with facility owners and IBR manufacturers to ensure facilities are studied and performance is verified for all credible system conditions	Mid-term
	Performance Requirements for IBRs	• Review existing IBR performance requirements to identify gaps in best practices, determine appropriate actions and implement requisite change	Mid-term
	Further Analysis and Mitigation Investigation in Identified Weak Areas	• Work closely with both TFOs and DFOs in the weak areas to conduct an assessment evaluating the impact of system-strength shortfall on both the distribution and transmission protection systems as well as power quality	Mid-term
Low	Protection System Requirements	• New protection technologies (e.g., adapted distance protection algorithms, time domain protection functions, wind area monitoring protection, and control systems) need to take into account system-specific conditions to be effective	Long-term

Priority	Category	Action	Time Horizon
		• Monitor impact of IBR penetration on protection systems and determine long-term strategy for addressing in weaker areas of the AIES	
	Performance Requirements for IBRs	• Develop performance requirements that leverage new inverter technology capabilities (e.g., grid-forming inverters)	Long-term
	Tools and Procedures for Real-time Operation	• Implement automated, accurate data-collection processes for post-event analysis and operation studies	Long-term

5 Flexibility Capability

5.1 Reliability Issues

System flexibility capability refers broadly to the ability of the electric system to adapt to dynamic and changing conditions while maintaining balance between supply and demand. Flexibility capability can be considered within several timeframes:

- Planning for new generation resources (over a period of years)
- Committing assets to align available supply with demand (days to hours)
- Ramping capability to match the size, speed, and frequency of large net demand ramps (hours to minutes)
- Scheduling and dispatching assets to balance supply and demand (hours to minutes)
- Capability of regulating reserves to manage net interchange (minutes to seconds)

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. Therefore, this section specifically addresses the ability of the electric system to balance supply and demand through scheduling and dispatching assets, as well as key metrics to gauge asset commitment and ramping capability.

5.1.1 Resource Adequacy and Asset Commitment

Resource adequacy was modelled within the AESO Net-Zero Report.[21] The Resource Adequacy Model (RAM) calculates the tradeoff between capacity (MW) and reliability, measured as expected unserved energy in megawatt hours (EUE MWh), using a probabilistic approach that varies load and generation. The results are measured against the Long-Term Adequacy Threshold as outlined in Section 202.6 (5) of the ISO rules, *Adequacy of Supply*.[22]

Supply shortfalls have many drivers, including:

- High load
- Low conventional generator availability
- Low variable resource output
- Low water inflows to energy-limited hydro
- Low or zero intertie availability

[21] Available at https://www.aeso.ca/market/net-zero-emissions-pathways/

[22] Available at https://www.aeso.ca/rules-standards-and-tariff/iso-rules/complete-set-of-iso-rules/

As this flexibility capability assessment was modelled using the AESO Net-Zero Report, the flexibility capability results inherently captured the expected unserved energy. However, the RAM did not consider forecast error and, therefore, did not capture the effects of forecast error on expected unserved energy.

The practice of self-commitment allows assets to offer in a manner that can result in the unit cycling on and off. Assets, especially long lead time assets, rely on forecasts to determine self-commitment. Inaccurate forecasts can result in suboptimal self-commitment, which can impact energy market prices and, in extreme cases, result in supply surplus or supply shortfall.

Additionally, long lead time assets may not be flexible enough to meet the cycling needs of the system. For example, solar generation can reduce the real-time power need from dispatchable generation during peak solar hours. If solar generation is relatively large, long lead time assets could be forced to choose between staying online versus shutting down. If they stay online, then the risk of supply surplus increases. Conversely, if they shut down, then they may not be able to come online as the solar generation retreats, which increases the risk of supply shortfall.

Although this concern is partially captured within the RAM, which showed in the AESO Net-Zero Report that the system would have sufficient resources to cover load with some caveats, a deeper dive specifically into flexibility needs highlighted a risk that the modelling of asset commitment favoured supply surplus reducing the expected unserved energy. For example, as the number of supply surplus events increases, asset offer strategies may change to be offline more often, shifting risk away from supply surplus towards supply shortfall. If this behaviour materializes, the additional supply shortfall could be mitigated through increased flexibility that can respond to cycling needs.

5.1.2 Ramping Capability

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 the change in load demand minus the change in variable generation production. The net demand variability requires the electric system to respond within a timeframe from a few minutes up to an hour or two.

Dispatchable generation provides the ramping capability to match the size, speed, and frequency of the net demand ramps. As more variable generation is integrated into the electric system, additional ramping capability may be required to respond to the production variability of the variable generation. Without adequate ramping capability, the electric system could have large power imbalances sustained over long durations.

The AESO utilizes Section 304.3 of the ISO rules, *Wind and Solar Power Ramp Up Management*[23] to limit the ramp-up of variable generation to the ramp-down capability of dispatchable generation.

5.1.3 Area Control Error

The AESO currently relies on three primary approaches 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

[23] Available at https://www.aeso.ca/rules-standards-and-tariff/iso-rules/complete-set-of-iso-rules/

- Regulating reserve ramp-up or down, via automatic generation control, to address minute-by-minute changes in demand and variable generation
- Section 304.3 of the ISO rules, *Wind and Solar Power Ramp Up Management*[24] 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 are known as the area control error (ACE), which considers the difference between the actual interchange and scheduled interchange (instantaneous interchange), frequency bias, time error, and a correction for metering error. The resulting instantaneous interchange with adjacent balancing authorities or deviations in system frequency 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 the AESO's obligations and other members of the WECC, to effectively and efficiently mitigate risks to the reliability and security of the Western Interconnection.

As more variable generation is integrated into the electric system, managing ACE will become more difficult due to larger net demand variability and forecast uncertainty. Regulating reserve is used to manage ACE by automatically controlling the regulating reserve output to minimize power imbalances.

5.2 Operational Experience

Some of the reliability issues identified previously are starting to be observed in real-time operations. Appendix C, section 1.1 provides more details for the following observations:

- On February 5, 2022, the wind forecast underestimated a reduction in wind production by approximately 550 MW, which resulted in the energy market being dispatched to nearly the top of the merit order. Offline generators were not flexible enough to cycle on under short notice
- Concerns with short-term wind and solar forecasting accuracy are leading to a reactive dispatching practice
- Some spinning reserve resources have been delaying their response to nearly the maximum allowed before starting to ramp which is impacting timely system responsiveness

5.3 Market and Dispatch Assessment

The AESO completed market and dispatch simulations (Appendix C, section 1.3) 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, Clean-Tech Scenario, and Renewables and Storage Rush Scenario. The flexibility parameters that were assessed in the simulation results included supply cushion, supply surplus, asset on/off cycling, ramp distribution, ramping capability, forecast uncertainty, and area control error distribution.

[24] Available at https://www.aeso.ca/rules-standards-and-tariff/iso-rules/complete-set-of-iso-rules/

The key findings from the flexibility capability assessment are as follows:

- System flexibility requirements are generally increasing with increased penetration of variable generation, specifically in the latter half of the 2020s
- The energy market will experience limited supply cushion and supply surplus more often, increasing the benefit from assets that have more commitment flexibility
- Net-demand changes will become more frequent and larger, increasing the need for system ramping capability
- Greater amounts of energy market dispatch, regulating reserves, and instantaneous interchange will be required to respond to more frequent and larger net-demand changes
- Increased mitigation for system flexibility will be required by the mid-2020s

Flexibility requirements continue to primarily reflect the timing of variable generation capacity additions, particularly in the later years of the forecast period and with the relative increase in variable generation capacity from the Reference Case, through the Clean-Tech Scenario, to the Renewables and Storage Rush Scenario. The flexibility assessment identified the following trends, with more detail provided in Appendix C, section 1.2:

- Asset commitment timeframe
  - System reliability may decrease with very low levels of supply cushion occurring more frequently, based on trends illustrated in Appendix C, Figure 23
  - Market operation may be challenged with increasing frequency of supply surplus, based on trends illustrated in Appendix C, Figure 24
  - Baseload dispatchable generating assets will be subject to more frequent on/off cycling based on trends illustrated in Appendix C, Figure 25
- Ramping capability
  - The ability to respond to net demand changes through energy market dispatch will be increasingly challenged by more frequent and larger net demand changes, based on trends illustrated in Appendix C, Figure 26 and Figure 27
  - The ability to respond to net demand changes through energy market dispatch may be supported by faster ramp rates and stable or decreasing response delay of dispatchable generation, based on trends illustrated in Appendix C, Figure 28 and Figure 29
- Dispatch timeframe
  - 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 and solar generation forecast errors, based on trends illustrated in Appendix C, Figure 26, Figure 27 and Figure 30
  - Greater amounts of market dispatch will be utilized in responding to more frequent and larger net demand changes, which will result in increasing cumulative absolute ramp of dispatchable resources, based on trends illustrated in Appendix C, Figure 31, Figure 32 and Table 9
  - 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 Appendix C, Figure 33

- Supply and demand imbalance
  - 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 Appendix C, Figure 32 and Table 9
  - Instantaneous interchange with adjacent balancing authorities will be increasingly relied on to respond to more frequent and larger net demand changes, based on trends illustrated in Appendix C, Figure 32, Table 9, Figure 34, and Table 10

5.4 Potential Mitigations

This section provides potential mitigation options, at a high level, for trends observed in section 5.3. The presented potential mitigations are not exhaustive and have not been analyzed for feasibility and additional options may be identified. The AESO will continue to monitor and evaluate system flexibility requirements along with assessing potential mitigations. The market-based mitigation options will be considered as part of a holistic review of the required evolution of the energy market, considering both short-term and long-term requirements.

Trend	Option	Description
Asset commitment timeframe Primarily focused on aligning commitment of supply with demand to reduce the risk of supply shortfall Potential mitigations can also help to manage supply surplus hours	Process-based	• Potential to improve short-term forecasts and provide a more detailed adequacy assessment that identifies types of supply, such as forecasted minimum stable generation, forecasted wind and solar generation, forecasted energy-constrained supply, and forecasted available import capability • Improving the quality and granularity of information can help with asset commitment decisions
	Market-based	• Consider market mechanisms to increase commitment certainty or asset flexibility (e.g., modifications to the energy market price cap/floor, reliability must-run requirement, and day-ahead energy market)
	Rule-based	• n/a
Ramping capability Focused on ensuring that committed/available generators collectively have enough ramping capability to match the size, speed, and frequency of large net demand ramps	Process-based	• n/a
	Market-based	• Consider market mechanisms to incentivize ramping capability (e.g., modifications to the energy market price cap/floor, a shorter settlement period and ramping product)
	Rule-based	• Consider recommending modifications to Section 304.3 of the ISO rules, *Wind and Solar Power Ramp Up Management* [25] to include ramp-down limits

[25] Available at https://www.aeso.ca/rules-standards-and-tariff/iso-rules/complete-set-of-iso-rules/

Trend	Option	Description
Dispatch timeframe Focused on improving the commitment and dispatching of assets to balance supply and demand by the hour or minute	Process-based	• Potential to improve short-term forecasts and implement processes and/or tools to enable more frequent and granular dispatches to achieve better alignment of supply with demand (e.g., automated dispatching tool)
	Market-based	• n/a
	Rule-based	• Consider recommending modifications to Section 203.4 of the ISO rules, *Delivery Requirements for Energy*[26], to improve the quality of responses to energy market dispatches • Rule modifications could include more granular ramp-rate submissions with tighter tolerances, while rule additions could include requiring assets to have an automated response to energy market dispatches
Supply and demand imbalance After the effect of the dispatch timeframe, any remaining imbalances between supply and demand have historically been managed through regulating reserve Potential mitigations include those which can improve the performance of regulating reserves	Process-based	• Consider process changes that target the effectiveness of regulating reserves, such as introducing a dynamic frequency bias
	Market-based	• Consider changes to the regulating reserve product to increase its effectiveness (e.g., dynamically calculating the required regulating reserve volumes based on forecasted attributes such as variability or adding new regulating reserve products to target a faster response)
	Rule-based	• Consider recommending modifications to Section 205.4 of the ISO rules, *Regulating Reserve Technical Requirements and Performance Standards*[27], to improve the regulating reserve performance • Rule changes could include modifying the response and ramp rate requirements to participate in regulating reserves or modifying performance standards to have the payment mechanism better reflect the quality of performance

5.5 Operational Readiness

This section details how trends identified in the market and dispatch simulation results (section 5.3) can impact operations.

- System Controllers face heightened uncertainty when dispatching during supply surplus conditions due to the typically small size of pro rata dispatches allocated to each asset relative to their allowable dispatch variance. This uncertainty is expected to occur more often as the number of supply surplus hours is expected to increase.
- System Controllers dispatch the energy market to maintain supply and demand balance. The variability of wind and solar assets can make that task challenging. As wind and solar penetration increases, an improved near real-time wind and solar forecast will need to be prioritized, which will improve the Systems Controllers' abilities to manage the supply and demand balance.

[26] Available at https://www.aeso.ca/rules-standards-and-tariff/iso-rules/section-203-4-delivery-requirements-for-energy/
[27] Available at https://www.aeso.ca/rules-standards-and-tariff/iso-rules/complete-set-of-iso-rules/

5.6 Action Plan

The Reliability Roadmap assessment forecasts the effects of increasing variable generation from renewables, more price-responsive load, growing volumes of distributed energy resources, and consumer adoption of new technologies on system flexibility capability through 2031. These changes have the potential to materially impact the reliability of the transmission system. In response, the AESO has developed a series of timely actions to continue to enable the electric system to balance supply and demand.

The flexibility capability action plan (Table 5) was developed with consideration of simulation results, potential mitigations, and assessment of operational readiness; details are provided in Appendix C, section 1.4. A list of the flexibility capability actions, priorities and time horizons to enable the electric system to adapt to dynamic and changing conditions while maintaining balance between supply and demand is included as follows.

Table 5: Flexibility capability action plan

Implementation Time Horizon: *Short-term is < 2 years | Mid-term is 2-5 years | Long-term is 5-10 years*

Priority	Category	Action	Time Horizon
High	Metrics	Define ramping metrics and requirements	Short-term
	Modelling Updates	Refine wind and solar modelling	Short-term
		Refine energy storage modelling	
		Refine dispatch modelling	
	Operational Preparedness	Wind and solar power ramp management improvements	Short-term
	Investigate Potential Mitigations	Evaluate process, market design and rule changes to improve flexibility capability	Short-term
Medium	Metrics	Refine metrics for supply and demand imbalance	Mid-term
	Modelling Updates	Refine load modelling	Mid-term
		Refine regulating reserve modelling	
	Investigate Potential Mitigations	Update engineering studies to determine regulating reserve procurement volumes	Short-term
	Operational Preparedness	Improve System Controller tools to enhance situational awareness and real-time decision-making ability	Mid-term
	Feedback	Analyze historical vs simulated data to improve simulations	Mid-term
Low	Metrics	Define asset commitment metrics	Short-term
	Investigate Potential Mitigations	Investigate dynamic procurement of regulating reserve	Short-term
	Operational preparedness	Improve dispatch certainty during supply surplus events	Short-term
	Modelling Updates	Continue to improve modelling assumptions, including generator fleet modelling such as EMMO offers and ramping behaviours	Mid-term

The Reliability Roadmap will inform the AESO's market evolution initiative, which will be evaluating potential changes to the market design. Herein, the AESO intends to evaluate potential market-based solutions for system flexibility, including the examples in section 5.4. Additionally, the AESO plans to evaluate the potential non-market-based mitigations with the intent to progress market and/or non-market mitigations for implementation within the next five years to ensure the required flexibility capability to manage reliability.

6 Summary of Roadmap Actions

In response to the reliability challenges identified through the Reliability Roadmap assessment, the AESO has determined specific initiatives that require urgent action as well as others that can be implemented over a longer time horizon. The AESO recognizes the importance of effective stakeholder engagement in offering insights into potential solutions and will be directly engaging stakeholders to advance the initiatives as appropriate. Following is a summary of the Reliability Roadmap actions that are planned to begin in 2023, followed by actions that could begin in the mid- or longer term. Some actions could take more than one year to complete.

6.1 Short-term Actions

Reliability Objective	Short-term (< 2 years)
Frequency Stability	• Implement the urgent plan to review and revise the LSSi/FFR Arming Table, pursue immediate FFR procurement when the AIES is operating as a frequency island, develop procurement for FFR services to be in service in 2025 (or earlier) and procure additional FFR as required • Complete the technical assessment including FNDR service assessment, verify angle stability on AC intertie due to inrush, and survey generating facility owners in Alberta to identify limitations on RoCoF • Evaluate MSSC Option paper responses and make recommendation • Evaluate RFI for Solutions to Mitigate the Instantaneous Impacts of Sudden Supply Loss submissions and communicate next steps • Develop real-time monitoring tool for PFR capability and frequency response obligation and investigate EMS dynamic frequency bias • Assess the system's capability to meet frequency regulating requirements imposed by BAL-003
System Strength	• Perform detailed EMT studies in weak areas of AIES and investigate mitigation solutions • Investigate whether market-based or wires-based solutions for improving system strength are warranted in areas where IBRs are unable to meet the enhanced requirements • Confirm that re-tuning of controls can be adopted to alleviate the observed reliability issues in the weak areas of the AIES and facilitate a coordinated collaboration with all involved stakeholders to re-tune existing plant controls • Establish mandatory requirements for GFOs to provide validated phasor domain and EMT IBR models • Include a SCR-based screening assessment in interconnection studies to identify the risk of reliability issues tied to system strength shortfall while connecting IBRs • Establish network and system monitoring to enhance visibility to real-time instability and power system security • Conduct regular system inertia and system strength studies to identify potential upcoming real-time operation concerns to mitigate in a timely manner

Reliability Objective	Short-term (< 2 years)
Flexibility Capability	• Define ramping metrics and requirements • Define asset commitment metrics • Refine modelling for wind and solar, energy storage and dispatch • Improve wind and solar power ramp management • Evaluate process, market design and rule changes to improve flexibility capability • Investigate dynamic procurement of regulating reserve • Update engineering studies to determine regulating reserve procurement volumes • Improve dispatch certainty during supply surplus events

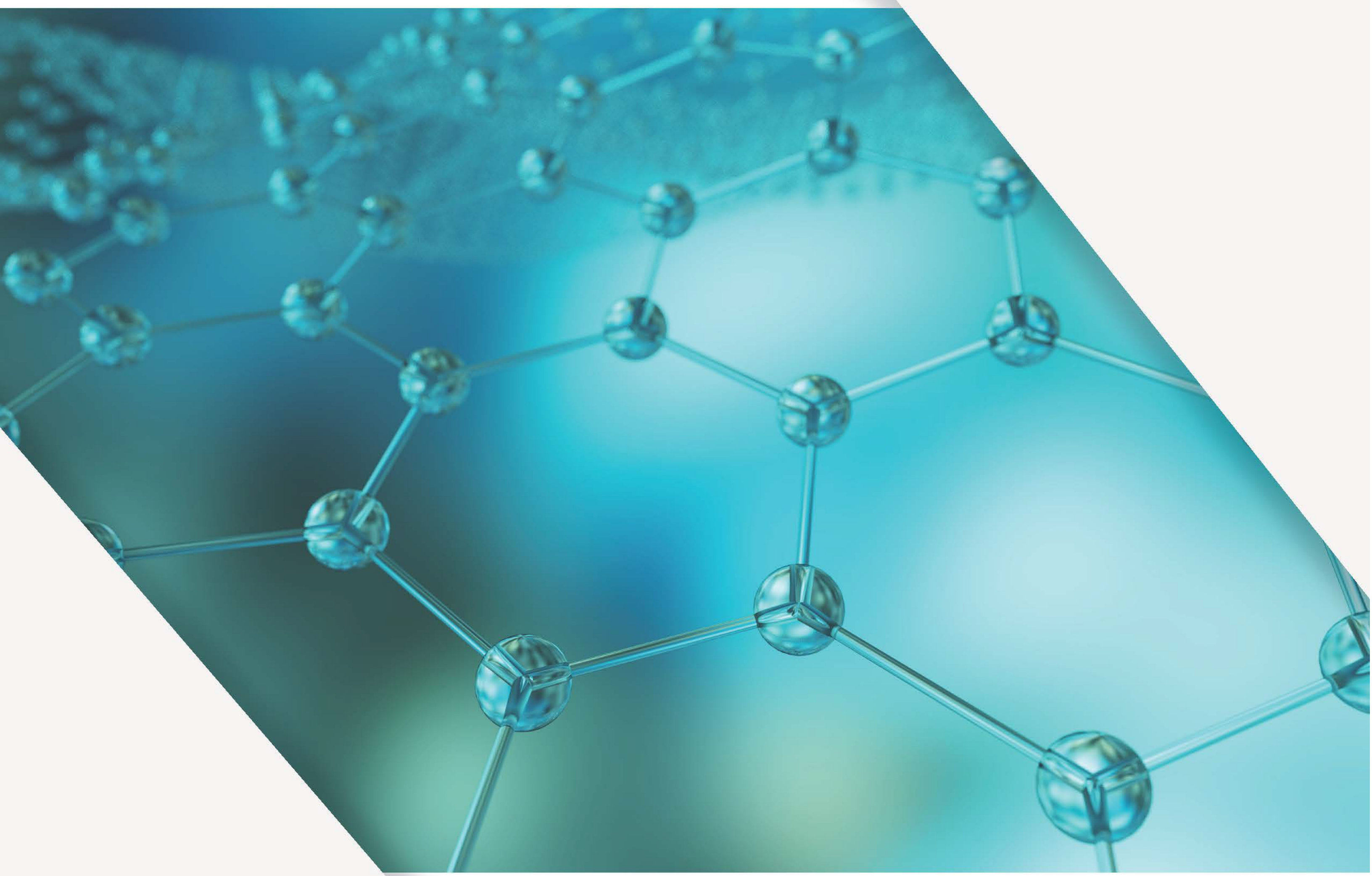
6.2 Mid- to Longer-term Actions

The following actions will likely be initiated in mid- to longer-term time frames:

Reliability Objective	Mid- to Long-term (2 – 10 years)
Frequency Stability	• Investigate rules-based solutions for frequency performance, which may include performance-based ISO rules for frequency regulation, synthetic inertia requirements for IBRs, OR re-qualifications, or the requirement for non-dispatchable generators to carry headroom for under-frequency response • Investigate market-based solutions for frequency performance, which may include a fast ramp product, must-run contracts (for inertia), adjusted OR volumes, pay-for-performance PFR, and other options
System Strength	• Integrate EMT studies into assessments for real-time operation • Build real-time and forward-looking stability, adequacy, and risk assessment tools for situational awareness and proactive decision-making with the ability to detect oscillations and to forecast system conditions • Supplement study models with post-commissioning disturbance monitoring to further improve the quality of the model and capture ongoing adjustment of model parameters over the lifetime of the equipment • Implement a feedback loop from real-time operations to ensure model accuracy • Improve the modelling process to clearly articulate study types and requisite supporting (e.g., dynamic, steady-state, short-circuit, and EMT) model requirements as applicable • Augment SCR-based screening with a detailed EMT simulation in areas prone to system strength shortfall to further evaluate reliability risks and failure modes • Work with facility owners and IBR manufacturers to ensure each facility is studied and performance is verified for all credible system conditions • Develop an integrated generator interconnection and long-term transmission planning process • Review existing IBR performance requirements to identify gaps in best practices, determine appropriate actions and implement requisite change

Reliability Objective	Mid- to Long-term (2 – 10 years)
	• Work closely with both TFOs and DFOs in the weak areas to conduct an assessment evaluating the impact of system strength shortfall on both the distribution and transmission protection systems as well as power quality • Ensure new protection technologies (e.g., adapted distance protection algorithms, time domain protection functions, wind area monitoring protection, and control systems) consider system-specific conditions to be effective • Monitor the impact of IBR penetration on protection systems and determine the long-term strategy for addressing in weaker areas of the AIES • Develop performance requirements that leverage new inverter technology capabilities (e.g., grid-forming inverters) • Implement automated, accurate data-collection processes for post-event analysis and operation studies
Flexibility Capability	• Improve the dispatch simulator to enable further improvements, including dispatch and regulating reserve modelling and load modelling • Continue to improve modelling assumptions, including generator fleet modelling such as EMMO offers and ramping behaviours • Refine metrics for supply and demand imbalance • Improve System Controller tools to enhance situational awareness and real-time decision-making ability • Monitor balancing error on an ongoing basis and adjust regulating reserve procurement as needed • Improve simulations by analyzing historical vs simulated data • Consider modifications to rules with the intent of improving flexibility • If needed, investigate new market-based solutions for system flexibility

In Alberta's deregulated competitive market, overall market design is key to incenting investment and operation of assets. Designing market signals, through market solutions or product designs, is part of the action plans identified for each reliability area in this report. The market-related mitigation options identified to address the reliability issues will be considered as part of a holistic review of the required evolution of the energy market to support Alberta through the transformation to a decarbonized future. This is the next stage, building upon the AESO Net-Zero Report and this Reliability Roadmap, in the AESO's role of enabling the transformation of the power system.



Appendix A: Frequency Stability

Appendix A: Frequency Stability

1.1 AESO Frequency Stability Obligation

ARS BAL-003-AB 1-1.1 addresses the frequency-response obligation applied to the AESO, which indicates the minimum frequency response in MW/-0.1Hz carried by every BA so that all interconnected BAs will adequately respond to the event causing system frequency excursion. The frequency response obligation is calculated by the WECC pro rata based on the total generation and total load of each BA and is implemented through frequency bias settings in AGC in the Energy Management System (EMS) in real-time. Ideally, the frequency bias reflects the actual frequency response in the BA and can be measured through the event analysis.

The WECC updates both frequency response obligation and frequency bias annually for all BAs in the Western Interconnection. The frequency response obligation assigned to the AESO is 83 MW/-0.1Hz and the frequency bias setting used in EMS is 148.7 MW/-0.1Hz in 2021[28]. The AESO has a responsibility to meet the frequency response obligation for compliance. The actual frequency response in real-time in the AIES is dependent on the generation status and load conditions, and the frequency response may drop in some scenarios (e.g., in high wind and high import). The AESO's frequency response to frequency excursion is analyzed by the Northwest Reserve Sharing Group (NW-RSG) on behalf of the WECC.

The AESO's average frequency response performance in a calendar year must meet its frequency response obligation. With higher penetration of IBRs driven by renewables generation, the system frequency response in the AIES is anticipated to become lower unless appropriate mitigation actions are taken. The AESO will proactively work on a frequency response action plan to ensure its compliance with BAL-003-AB 1-1.1.

1.2 Frequency Stability Assessment

FREQUENCY STABILITY MODELLING

Technical assessment on frequency stability is to confirm frequency stability issues the AESO is currently experiencing and future anticipated issues, and to quantify the magnitude of the problem. The assessment can also experiment with different mitigation solutions to ascertain their effectiveness. More importantly, the assessment results can guide the AESO's work with industry to decide on the preferred solutions and execute the action plan accordingly to ensure that frequency stability is well managed.

The following objectives need to be achieved through the technical assessment:

- Identify the root cause of frequency stability issues
- Identify the probability of UFLS activation due to loss of supply
- Check the impact on frequency stability by different AESO initiatives
- Quantify different mitigation solutions to reduce the probability of UFLS activation

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[28] If a Balancing Authority such as the AESO decides to use a fixed frequency bias setting, the frequency bias setting is selected between 100% and 125% of median Frequency Response Measures (FRM) in the previous year. The median FRM was calculated based on the actual system frequency response in selected 20-25 events in the previous year. The frequency bias setting is used in the AGC to automatically direct the output of regulating reserve for balancing purpose. The frequency bias cannot be less than the frequency response obligation.

- Validate the probability of UFLS activation in years 2021, 2026 and 2031 to quantify the deteriorating frequency performance in a 10-year horizon, and the required mitigation
- Support risk-based decisions

The study process was designed to achieve the objectives as shown in the following diagram. The AESO selected 2021, 2026 and 2031 to represent trending over a 10-year horizon. The system condition in 2021 is based on historical system data and the system conditions in 2026, and 2031 are based on forecast cases published by the AESO.

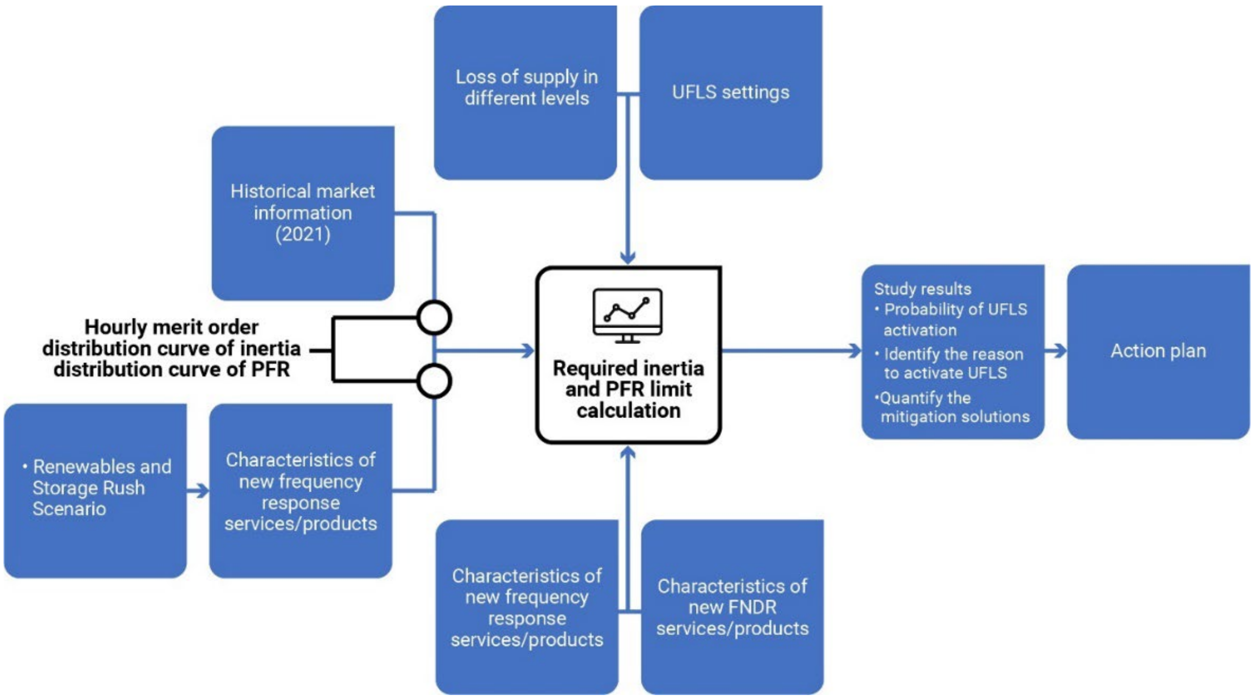
In this assessment, two different forecast cases were tested in years 2026 and 2031: the 2021 LTO‘s Clean-Tech Scenario and the AESO Net-Zero Report’s Renewables and Storage Rush Scenario. Both scenarios have a higher penetration of IBRs driven by renewables generation, resulting in lower system inertia and lower PFR, which is conclusively leading to less frequency response. Additionally, the forecast scenarios include the hourly operational points in the AIES with information on the system inertia and PRF. The AESO is therefore able to plot the density of hourly operational points in two dimensions in terms of the system inertia and PFR.

The AESO utilized the model to:

- Calculate the limit of required system inertia and PFR to avoid UFLS activation given the size of supply loss and UFLS settings
- Test different frequency response products with different settings to check their effectiveness to improve the frequency response in the AIES
- Project the density of operational points in a particular year on the limits of required system inertia and PFR in a single plot and calculate the confidence to avoid UFLS activation by the comparison
- Tested the FNDR—as one of few effective potential solutions to mitigate or offset intertie in-rush flow—to see how it impacts the frequency stability

A detailed explanation of the study results will be discussed in Appendix A, section 1.4. It is noteworthy that FNDR—as the effective solution to offset intertie in-rush flow—was also tested to see how it impacts the frequency stability.

Figure 9: Study process diagram



MODEL AND ASSUMPTIONS

The AESO created a frequency response model and incorporated reasonable assumptions to support the assessment. The AESO will continue to improve the model and assumptions to respond to changing operating conditions to support the validity of the study results.

Frequency Response Calculation

Both historical data and forecast scenarios include hourly operational data, generator status and projected dispatch. Additionally, all existing and forecasted generation in the scenarios include expected inertia levels and assumed PFR based on historical observations to enable these to be calculated on an hourly basis for each year studied.

Based on positive results from the proof-of-concept tests, the AESO used simplified system-level calculations over a time range to simulate the frequency to calculate the frequency response instead of dynamic simulation on PSS®E software, which heavily depends on the completeness of the power system model to meet the study objectives.

Frequency Response from Load

Theoretically, loads can provide frequency response. In the study, there is an assumption that the PFR contribution from loads is a constant at 13.2 MW/0.1Hz, which roughly corresponds to 8,000 MW of AIL and a 1 load-damping constant. This is a conservative assumption because AIL typically exceeds 8,000 MW in most of the hours during a year, and the load-damping constant is typically larger than 1. Therefore, the actual PFR in real time is likely larger than the PFR value from hourly operational points used in the study. The AESO applied this assumption to simplify the calculations and presentation of results and will consider how to incorporate a varying load response into future assessments.

RoCoF Consideration

As discussed in section 3.1.2, generators may apply a RoCoF limit in their generation protection scheme. Sharp RoCoF in real-time beyond the limit will result in generators tripping. Ideally, RoCoF should be one of the reliability criteria to check in the study and the desired system RoCoF after supply loss should be checked against generation protection settings to avoid generation tripping. However, there are no existing ISO rules which specify a RoCoF limit at present, and the AESO will need to engage with generators to improve visibility to the RoCoF limit generators use in their protection schemes. As such, an AIES-specific RoCoF limit cannot be incorporated into this assessment. Instead, the AESO incorporated the RoCoF range recommended by other jurisdictions in Europe and North America as reference.

Topology Consideration

The study also found that AIES system inertia and PFR do not change significantly when the AIES is interconnected with the Western Interconnection with import, or when the AIES is islanded. Therefore, supply loss in the study can reasonably represent both scenarios, including supply loss inside the AIES and import loss after an intertie trip.

FFR Specifications

The AESO assumed FFR to have a trigger frequency at 59.5 Hz, and a response time of 200 milliseconds in alignment with the existing LSSi technical requirements.

FNDR Specifications

The AESO assumed FNDR to have a response time of 200 milliseconds.

METHODS

The AESO used a formula to calculate the frequency response instead of dynamic simulation on the PSS®E. Other considerations include:

- Inertia response after a supply loss follows Newton’s second law of motion
- The RoCoF is determined by the size of supply loss and system inertia
- The frequency will drop at the speed of the RoCoF, and the frequency can be calculated at any time point
- Conversely, the PFR indicates overall governor response of all generation in the system; it is an experienced curve without any equation to use

The AESO has historical data on power output from generators in response to frequency excursion events and dynamic simulation from other studies. In this study, the AESO used a combination of three first-order curves with different gains and time constants to mimic the PFR curve based on a benchmark. Optimization was performed to ensure the resultant PFR curve is representative and reasonably accurate given dispatch and generation fleet assumptions.

The formulaically calculated frequency response enables study flexibility. For a given supply loss and UFLS settings, the model can do a reverse calculation to identify the limit of required system inertia and PFR to avoid UFLS activation. When a certain frequency response product is added to help frequency response, the new limit of required system inertia and PFR can also be calculated.

The AESO also plots the density of operational points in a particular year in terms of system inertia and PFR. The density of operational points on top of limits of required system inertia and PFR are projected. This method allows the AESO to check the probability of UFLS activation due to supply loss, and support risk-based decisions in both technical and non-technical domains.

STUDY SCENARIOS

The AESO intends to include multiple scenarios in frequency stability assessment as shown in Table 6. These scenarios reflect the important initiatives the AESO plans to do. Their impact on the frequency stability is required to know when considering cost-benefit analysis of these initiatives.

Table 6: Studied scenario description

Diagram	Supply Loss (MW)	Scenario and Event Description
1	425	• Internal supply loss in current islanded MSSC limit, or B.C. intertie is tripped with total import of 425 MW on all the AC interties
2	735	• MATL is added with back-to-back HVDC converter. B.C. intertie is tripped with maximum import of 735 MW on it
3	935	• MATL is added with back-to-back HVDC converter, and AIR project increases the TTC of B.C. intertie. B.C. intertie is tripped with maximum import of 935 MW on it
4	1,135	• MATL is added with back-to-back HVDC converter, and both AIR project and CRPC project increase the TTC of B.C. intertie. B.C. intertie is tripped with maximum import of 1,135 MW on it
5	466	• Internal supply loss in current interconnected MSSC limit, or B.C. intertie is tripped with total import of 466 MW on all the AC interties
6	1,045	• Interties are tripped with maximum import of 1,045 MW on all the AC interties
7	1,245	• AIR project increases the TTC of B.C. intertie. Interties are tripped with maximum import of 1,245 MW on all the AC interties
8	1,445	• Both AIR and CRPC projects increase the TTC of B.C. intertie. Interties are tripped with maximum import of 1,445 MW on all the AC interties.

1.3 Inertia and PFR Characteristics in AESO Forecast

The frequency response of the AIES is greatly dependent on system inertia and PFR. The system inertia and PFR in 2021 are based on historical data, whereas the information in 2026 and 2031 is obtained based on the forecast scenarios. The summary of change in the system inertia and PFR is included in Table 7.

Table 7: Summary of system inertia and PFR in 2021, 2026 and 2031

	2021 (historical)	2026		2031	
			Change from 2021		Change from 2021
Clean-Tech Scenario					
System inertia – median (Gross Value Added [GVA])	52.5	48.4	-7.8%	48.3	-8%
System inertia – 5th percentile (GVA)	47.2	42.4	-10.2%	37.7	-20.1%
PFR – median (MW/-0.1Hz)	64.4	48.6	-24.5%	48.4	-24.9%
PFR – 5th percentile (MW/-0.1Hz)	49.1	35.5	-27.7%	32.4	-34%
Net-Zero Renewables & Energy Storage Rush Scenario					
System inertia – median (GVA)	52.5	52.2	-0.6%	49.1	-6.5%
System inertia – 5th percentile (GVAs)	47.2	44.2	-6.4%	38.2	-19.1%
PFR – median (MW/-0.1Hz)	64.4	60.6	-5.9%	52.4	-18.6%
PFR – 5th percentile (MW/-0.1Hz)	49.1	42.2	-14.1%	32.9	-33%

KEY FINDINGS

- While the average system inertia and PFR are declining from 2021 to 2031, the 5th percentile of system inertia and PFR is declining at a much higher rate
- Average and 5th percentile of system inertia and PFR in Clean-Tech Scenarios decline earlier than Net-Zero Renewables & Energy Storage Rush Scenarios
- Average and 5th percentile of system inertia and PFR in Clean-Tech Scenarios are slightly higher than Net-Zero scenarios; meaning that system inertia and PFR depend more on online conventional generation hourly rather than the penetration of IBRs
- The 5th percentile of system inertia and PFR has meaningful declines, especially in the latter half of the 2020s

1.4 Study Results

FREQUENCY STABILITY STUDY RESULTS WITH FFR

The results of frequency response are presented in two groups:

- FFR Group | As shown in Appendix A, Figure 10, checks all the AESO initiatives against frequency stability with the FFR as the only mitigation solution to frequency stability
- FNDR Group | As shown in Appendix A, Figure 16, checks how FNDR impacts the frequency stability
- Year 2021 is based on the historical data and Year 2026 and 2031 are based on the Clean-Tech Scenario and Renewables and Storage Rush Scenario (as part of Net-Zero Pathway case)

The diagrams in the FFR Group (Figure 11, Figure 12, Figure 13, Figure 14 and Figure 15) include three study years, i.e., 2021, 2026 and 2031. For each year, the study assesses eight different supply loss conditions related to different AESO initiatives. The diagrams are numbered from 1 to 4 in the first row and from 5 to 8 in the second row, based on the scenario numbers listed in Table 6. In each diagram, the X-axis is the system inertia, and the Y-axis is the generator PFR. The lines represent the limits of required system inertia and PFR to avoid UFLS activation with differing amounts of FFR to be armed. The more FFR to be armed, the lower the amount of required system inertia and PFR. In each limit line, the point of minimum required system inertia and the minimum required PFR is also identified. The dashed line connects the corners where the line transitions from being limited by system inertia to being limited by PFR. When comparing across the diagrams, it is obvious that the larger the supply loss, the higher the system inertia and PFR are required to avoid UFLS activation.

Another important consideration within the diagrams is RoCoF. For each point on the limit lines of required system inertia and PFR, the corresponding RoCoF can be calculated, and the results are colour-coded to indicate the range of values. Red indicates a RoCoF greater than 1 Hz/s which is outside of the recommended operating range based on practices within other jurisdictions.

Another important data point to consider in each diagram is the density of hourly system operational points in a particular year in terms of the AIES system inertia and generator PFR (which is represented by hexagons). By comparing the density of hourly operational points with the lines of required system inertia and PFR, it shows the probability of UFLS activation due to supply loss. For example, in the diagram with supply loss of 425 MW in 2021, as shown in Figure 11, without any support from FFR only 19 per cent of hours in 2021 have sufficient inertia and PFR to maintain system frequency without UFLS activation following supply loss of 425 MW. If 100 MW of FFR is used, then the probability will increase to 90 per cent.

It is also noteworthy that all operational points of the AIES in 2021 are located on the right side of the minimum required system inertia line for supply loss of 425 MW. This means that the system inertia is always more than the required minimum amount if there is sufficient PFR. Conversely, many operational points are located below the required minimum PFR line which means UFLS is likely to be activated due to the lack of PFR either simultaneously at the frequency nadir point or during frequency stabilization.

Figure 10: FFR Group | Results of frequency stability with FFR

Figure 11: Year of 2021

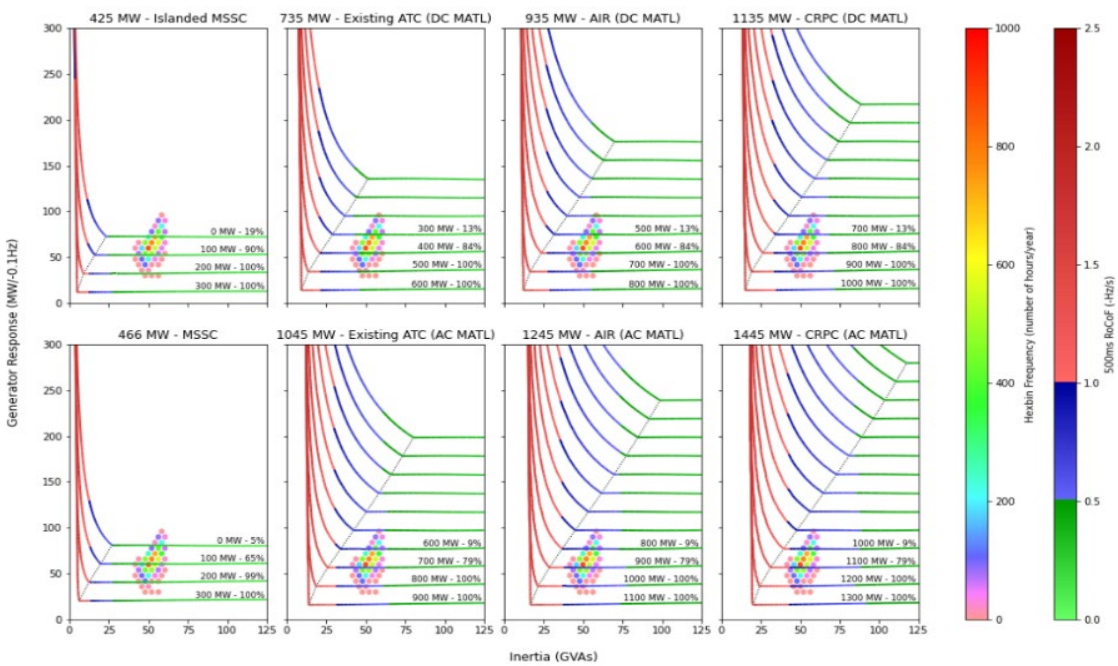


Figure 12: Year of 2026 (Clean-Tech Scenario)

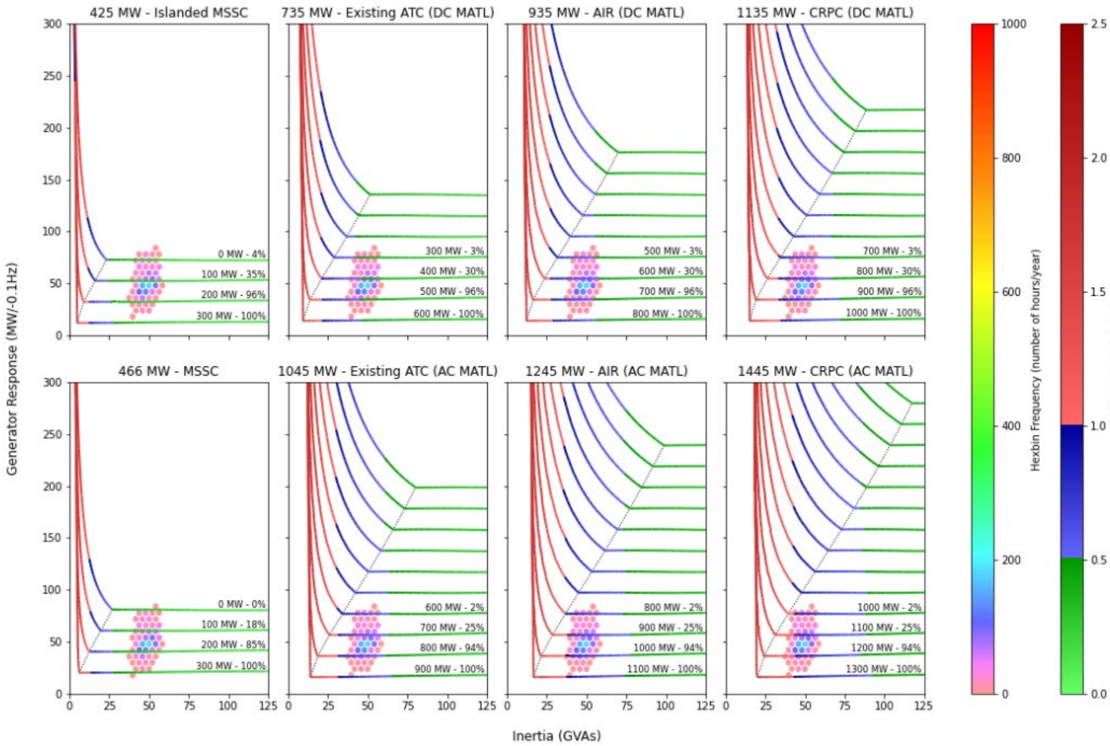


Figure 13: Year of 2026 (Net-Zero Scenario)

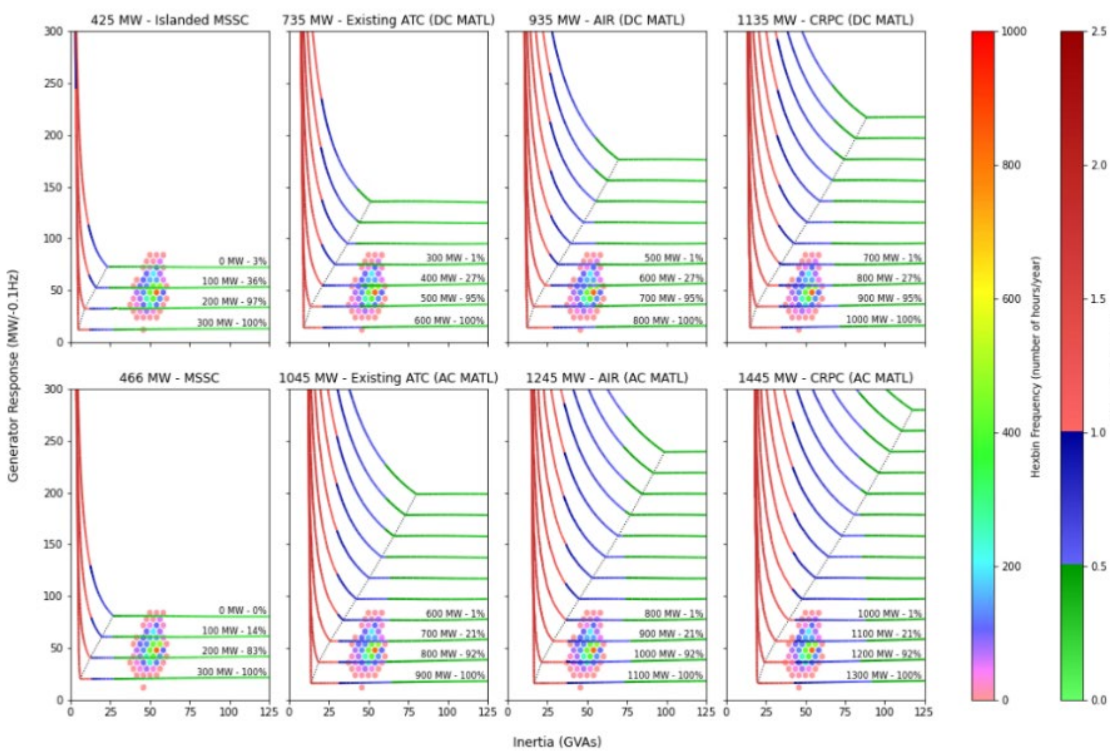


Figure 14: Year of 2031 (Clean-Tech Scenario)

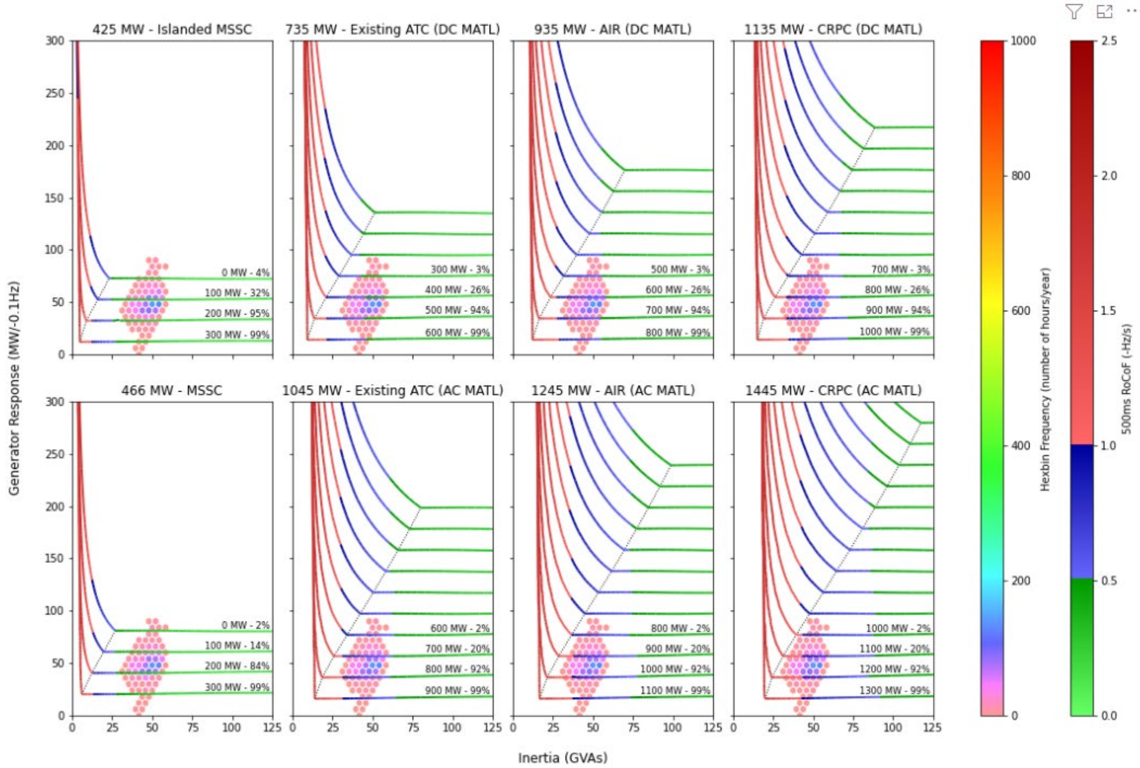
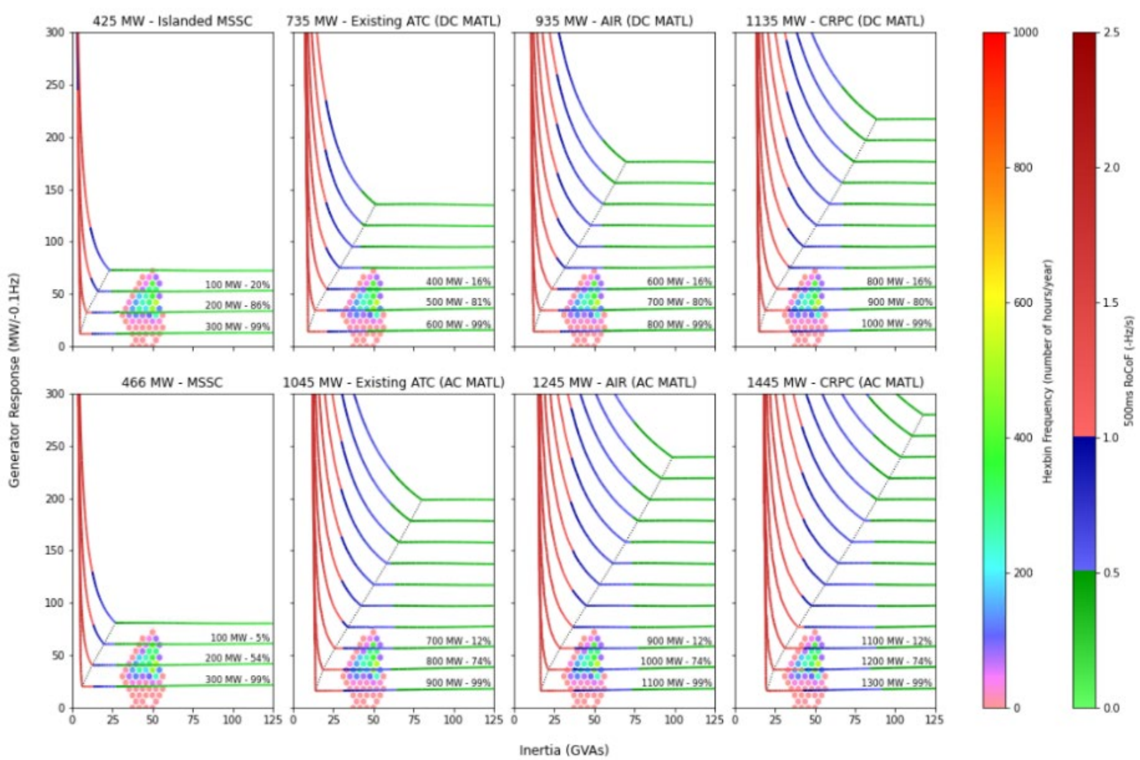


Figure 15: Year of 2031 (Net-Zero Scenario)



FREQUENCY STABILITY STUDY RESULTS WITH FNDR

FNDR is an event-triggered scheme to increase supply or reduce demand, unlike a frequency-triggered service such as FFR. For example, when the B.C. intertie is tripped, if the system frequency declines with a RoCoF equal to or less than 1 Hz/s, the system frequency can reach 59.5 Hz in 500 milliseconds or longer. This rapid decay triggers FFR to be deployed within 200 milliseconds. If FNDR is used as soon as the B.C. intertie breakers are open, FNDR can be activated within 200 milliseconds (12 cycles considering communication latency from the intertie breaker to the FNDR service provider) to avoid the initial 500 milliseconds or longer delay. As FNDR can be activated faster than FFR, it can be more effective at improving frequency stability considering both RoCoF and the frequency nadir point.

The study results for FNDR in Figure 16: FNDR Group | Results of frequency stability with FNDR are grouped and organized in the same way as the study results for FFR in Figure 10, i.e., the groups include three studied years. In each study year, eight supply loss scenarios were assessed and incorporated the same AESO initiatives as shown in Table 1: 2021 Action Plan | Operation experience and readiness for frequency stability.

Comparing all the diagrams in Figure 16: FNDR Group | Results of frequency stability with FNDR with the corresponding diagrams in Figure 10: FFR Group | Results of frequency stability with FFR, the impact of FNDR on frequency stability is similar to FFR albeit with a minor improvement in confidence.

Figure 16: FNDR Group | Results of frequency stability with FNDR

Figure 17: Year of 2021 (Historical data)

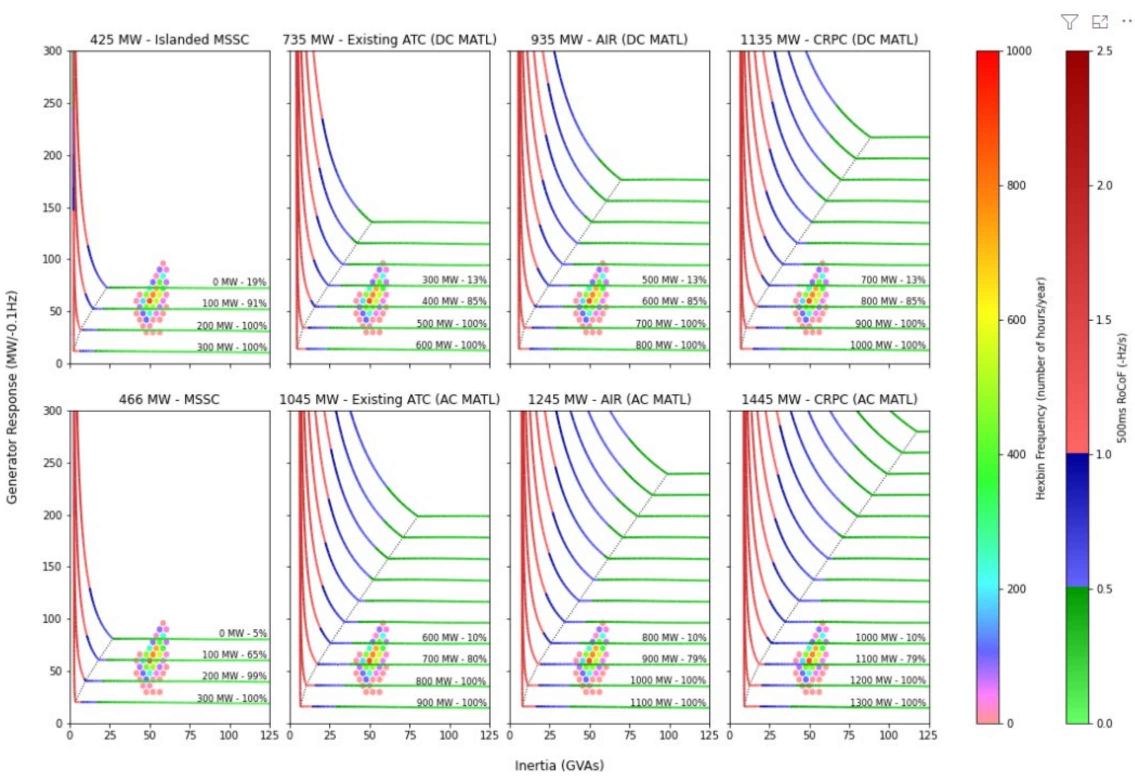


Figure 18: Year of 2026 (Clean-Tech Scenario)

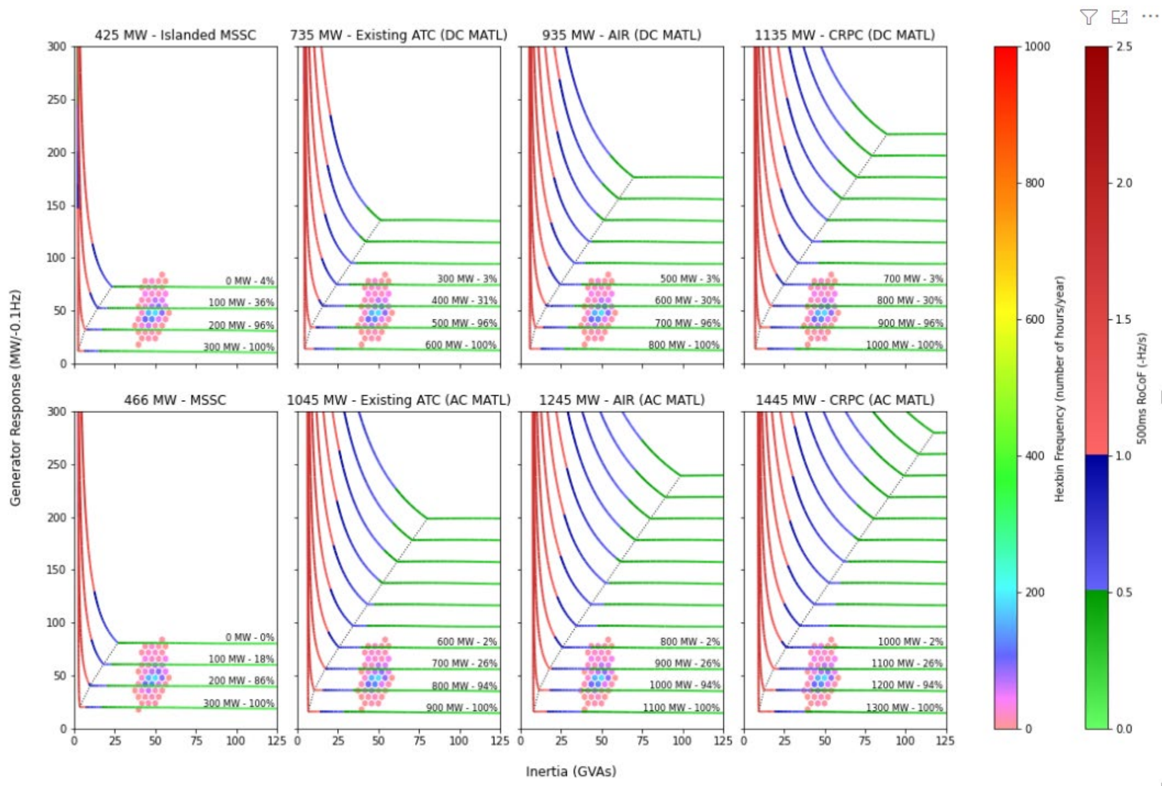


Figure 19: Year of 2026 (Net-Zero Pathway Scenario)

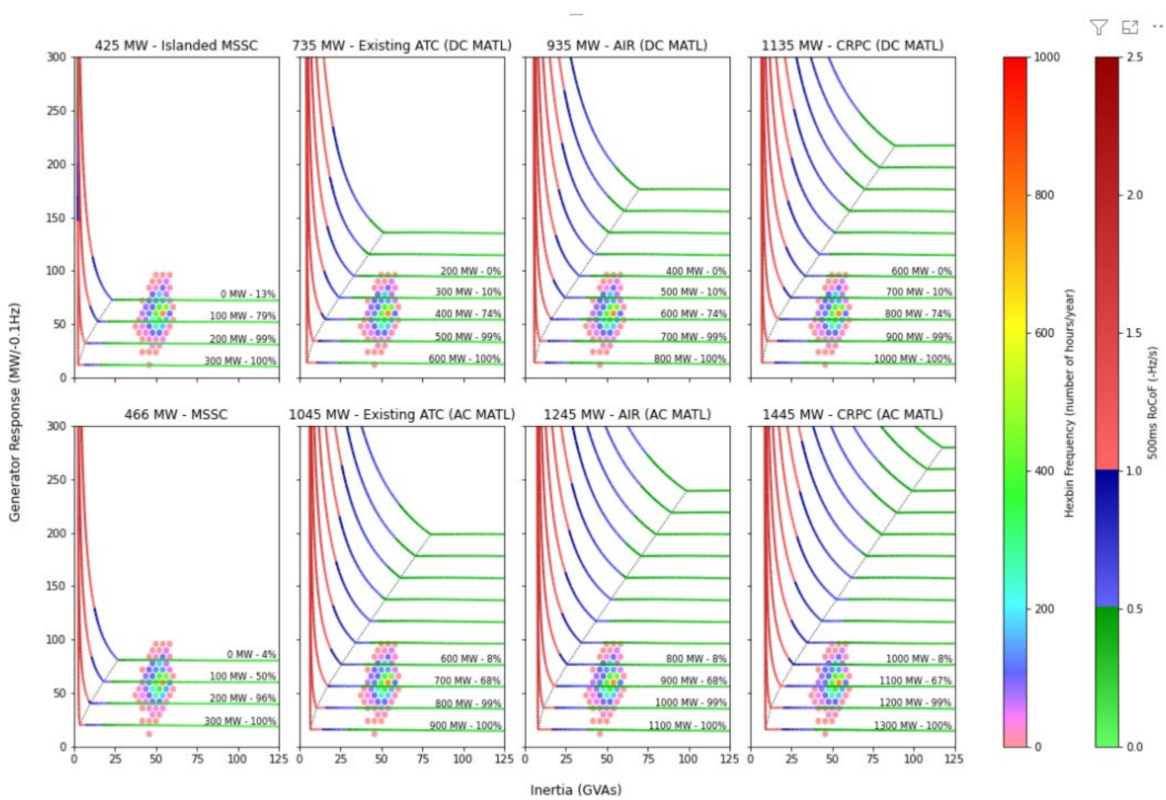


Figure 20: Year of 2031 (Clean-Tech Scenario)

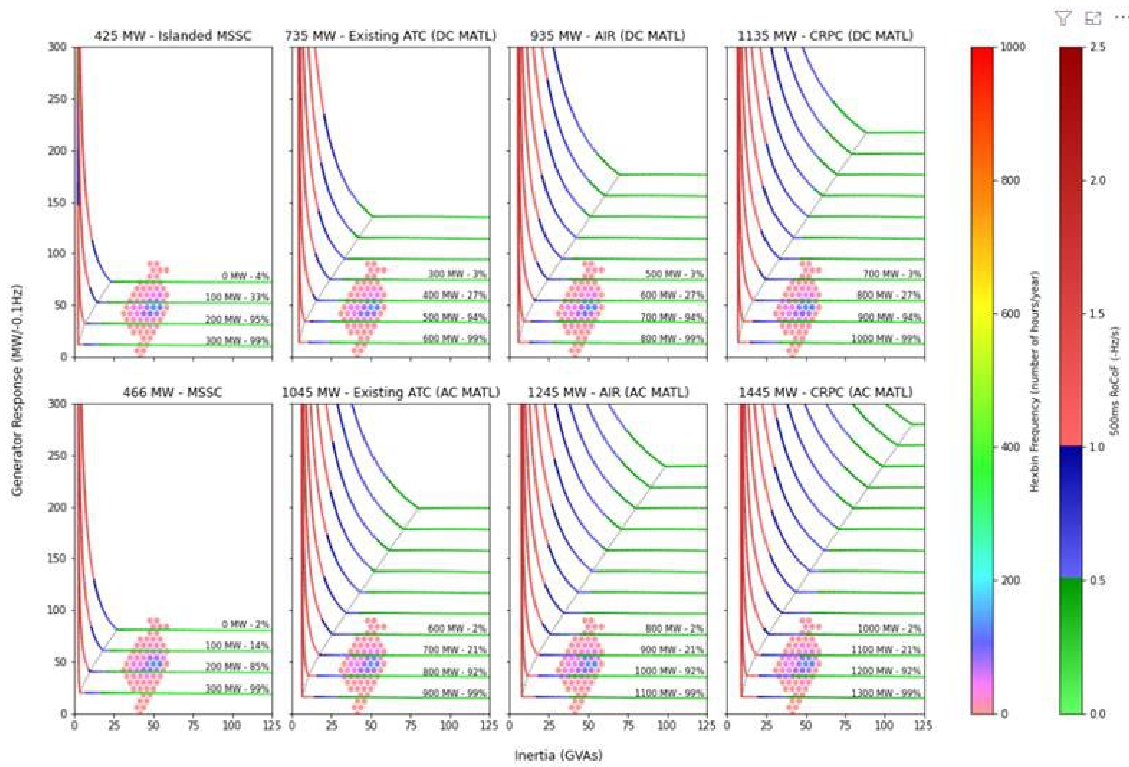
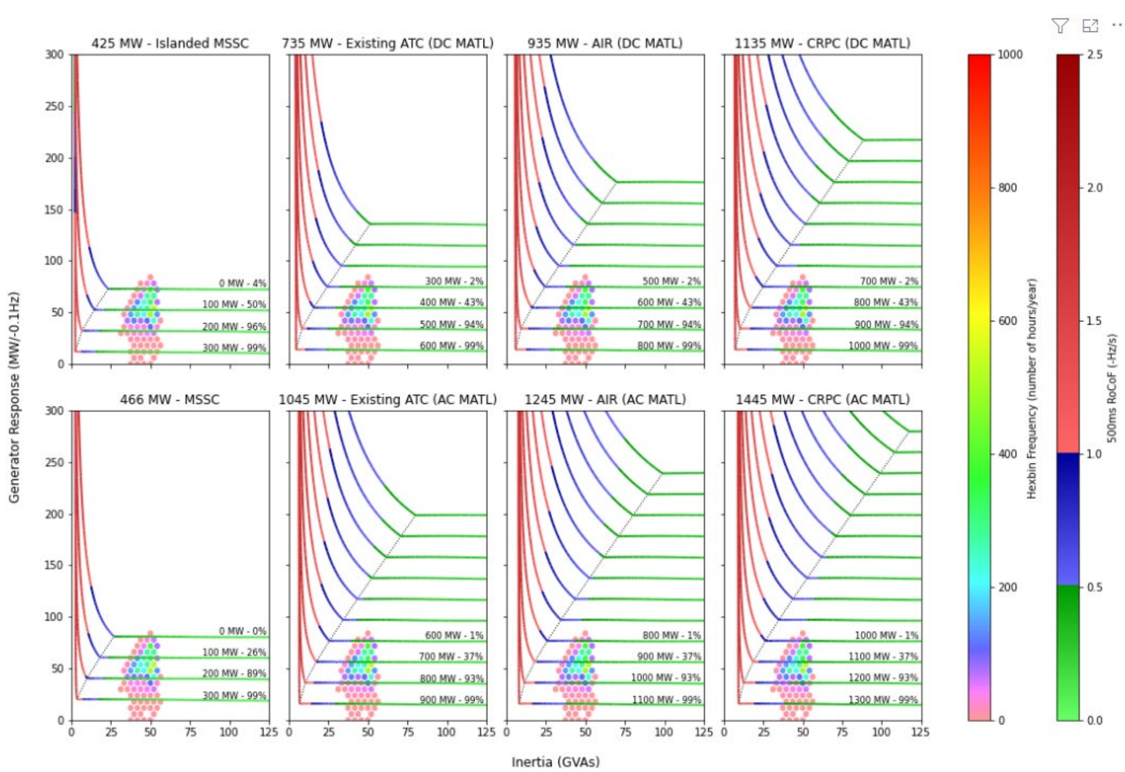


Figure 21: Year of 2031 (Net-Zero Pathway Scenario)



1.5 Possible Mitigation Solutions

The AESO categorizes the possible solutions based on the nature of the solutions targeting different reliability issues as shown in Table 8.

Table 8: Mitigation solutions

<table>
<tr><th colspan="2">Reliability Limits</th><th rowspan="2">Possible Solutions</th></tr>
<tr><th>Category</th><th>Sub-category</th></tr>
<tr><td rowspan="3">Frequency Stability</td><td>RoCoF</td><td rowspan="4">Rules-based | Modifying or creating ISO rules Wires-based | Adding transmission infrastructure Market-based | Modifying existing services or creating new services that can be procured through ancillary service markets or competitive processes, or changing how the energy and ancillary service markets are structured and operated</td></tr>
<tr><td>Frequency Nadir Point</td></tr>
<tr><td>Frequency Stabilization</td></tr>
<tr><td>Intertie Reliability</td><td>Intertie In-rush</td></tr>
</table>

It should be noted that the possible solutions, which remain to be evaluated, are not necessarily mutually exclusive, and a possible solution may be used to address multiple reliability concerns. Evaluation would identify the appropriate actions to take based on the specific issue to resolve, and the impact to market participants. The solutions the AESO ultimately endorses may be a combination of possible solutions across all these categories.

For education purposes, the AESO lists and describes a few possible solutions to mitigate different reliability concerns. It is noteworthy that this is not an exhaustive list of solutions yet. On September 29, 2022, the AESO issued an *RFI for Solutions to Mitigate the Instantaneous Impacts of Sudden Supply Loss* to the industry on possible solutions to mitigate frequency stability issues. The AESO is still processing the RFI response while this document is being released. The AESO currently does not have a preference for the solutions, particularly for long-term.

The potential solutions to mitigate the reliability risks triggered by weak power-system conditions include:

Lower MSSC Limit

Lowering the MSSC limit can keep the supply loss small enough to avoid UFLS activation with declining system inertia and PFR or excessive in-rush on the intertie. This solution could help mitigate the frequency nadir point and frequency stabilization.

Lower UFLS Settings

Lowering UFLS settings could be a straightforward way to mitigate frequency stability. When the AIES is interconnected with the Western Interconnection, UFLS settings are required to be the same across all interconnected jurisdictions. When the AIES is islanded, there may be an opportunity to lower the UFLS settings to allow larger frequency excursion. This solution could help the frequency nadir point and frequency stabilization.

Synch Condenser Installation

The AESO could add a synch condenser, even with a flywheel or something equivalent, as a transmission project or by contract with market participants to add more inertia into the AIES whenever the system inertia is low. This solution could help RoCoF and the frequency nadir point in the frequency stability. It is noteworthy that a synchronous condenser can also help system strength because of the high short-circuit current produced during a fault.

Synthetic Inertia

Synthetic inertia is a programmed response to frequency disturbances that can be offered by inverter-based resources. For example, synthetic inertia can be offered by inverter-based wind turbines. In a typical implementation, a wind turbine would detect an under-frequency event and respond by taking rotational kinetic energy from the turbine and using it to produce more than the baseline amount of electrical power for a temporary response period. After the response period, the turbine would be brought back up to operating speed and the generator would temporarily produce less than the baseline amount of electrical power.

Grid-forming Inverter-based Resources

Grid-forming technology is being developed to help IBRs function in synchronous electrical grids with a low proportion of conventional generators. IBRs typically use grid-following technology, which means they use Phase-Locked Loop (PLL) controls to follow voltage waveforms that ultimately originate from conventional generators. In contrast, grid-forming IBRs can generate waveforms by themselves and may emulate some desirable characteristics of conventional generators. Grid-forming technology is not yet standardized, nor is it required in the ISO rules, and is the subject of continuing research. Theoretically, grid-forming technology could help RoCoF and frequency nadir point in the frequency stability.

Wider Ride-through Range

All generation in the AIES is required to have frequency ride-through capabilities as per Section 502.1[29], 502.5[30] and 502.13[31] of the ISO rules for transmission-connected generation and IEEE 1547 for DERs enforced by DFOs. A wider ride-through range can allow more generation to continue to operate through frequency excursions; the generators that ride through events can continue to provide frequency response for the system.

Specification on PFR Performance

Existing ISO rules including Section 502.1[32], 502.5[33] and 502.13[34] enforce all transmission-connected sources including synchronous generation, inverter-based generation and battery storage to have primary frequency response function. However, the rules don’t specify the performance. The sources may not provide adequate PFR due to a shortage of generation headroom to increase the generation output or just poor control settings. The ISO rules could specify PFR performance criteria to ensure that the AIES can count all applicable sources to provide adequate PFR after the supply.

Fast Ramp

Fast ramp services respond to frequency decay by rapidly increasing generation to help stabilize frequency. This service can be triggered when the system frequency decays to a certain threshold value and could help with frequency stabilization and, depending on timing, provide some assistance toward increasing the frequency nadir.

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30 https://www.aeso.ca/assets/documents/502.5-Generating-Unit-Technical-Requirements-2.pdf

31 https://www.aeso.ca/assets/documents/502-13-Battery-Facility-Technical-Requirements-.pdf

32 https://www.aeso.ca/assets/documents/502.1-Aggregated-Generating-Facilities-Technical-Requirements.pdf

33 https://www.aeso.ca/assets/documents/502.5-Generating-Unit-Technical-Requirements-2.pdf

34 https://www.aeso.ca/assets/documents/502-13-Battery-Facility-Technical-Requirements-.pdf

FFR Procurement

As described in section 3.1.4, FFR is a technology-agnostic service used to help arrest and stabilize under-frequency excursions and response significantly faster than PFR. FFR deployment lowers the RoCoF, raises the nadir point of the frequency, and provides additional time for PFR to deploy and raise the stabilized frequency after supply loss. This solution could help the frequency nadir point and frequency stabilization in the frequency stability. Additional procurements of this service can help address expected declining primary frequency response.

FNDR Procurement

As described in section 3.1.4, FNDR is an event-based protection scheme to automatically and quickly reduce demand or increase supply. FNDR can offset the inadvertent increase in imports beyond the in-rush margin on the AC interties to prevent the intertie from tripping after a large supply loss. A large supply loss needs to have an adequate amount of FNDR to offset the in-rush beyond the margin on the intertie. FNDR requires infrastructure in place to support the function. Theoretically, FNDR needs to continuously monitor the status of all qualified contingencies and have a logic processor to decide on a tripping signal, and then send the tripping signal to FNDR providers. Communication in fibre optics will be required to have a reliable and short activation time. The detailed design of FNDR will need to be further assessed.

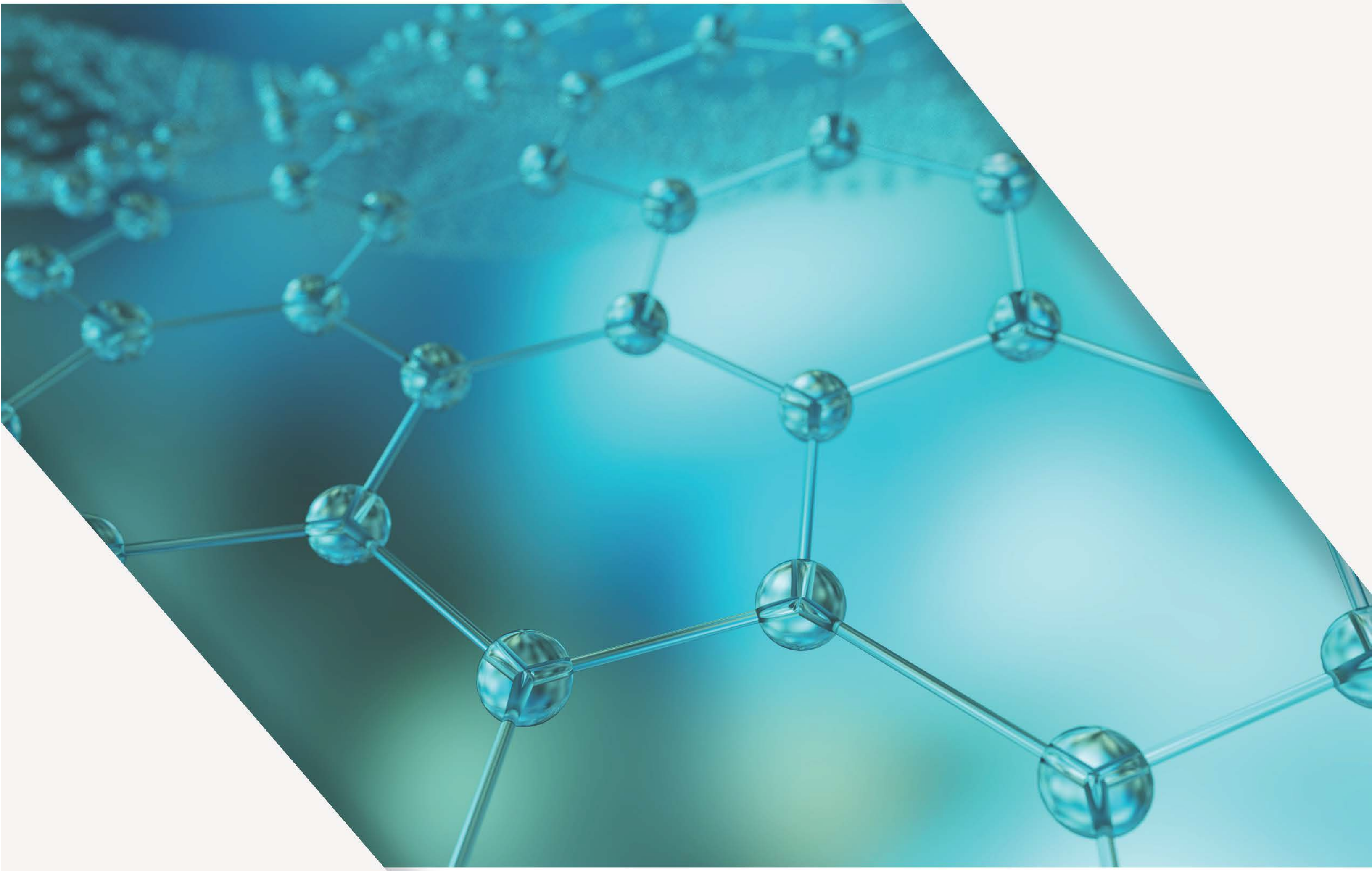
Unit Commitment

The AESO could add inertia and PFR as additional criteria as a market dispatch requirement as an option of last resort (i.e., this may be overly disruptive compared to the issue identified). Generation-providing inertia and PFR could have higher priority to be dispatched to ensure the minimum required system inertia or minimum required PFR can always be met. This solution could help RoCoF, frequency nadir point, and frequency stabilization in the frequency stability.

Other Jurisdictions

There are only a few jurisdictions in North America, and globally, that are facing similar challenges in frequency stability as Alberta, and these jurisdictions have common features. They all have varying penetration of IBRs driven by renewables generation in an islanded power system or weak interconnections with neighbouring systems. Hawaii Electric and the Electric Reliability Council of Texas (ERCOT) are leading entities dealing with frequency stability in North America. Utilities in Ireland, the United Kingdom and Australia have also introduced solutions to mitigate frequency stability in their power systems.

A broad jurisdictional review will be completed as part of this action plan, and the AESO will select the solutions most suitable to Alberta in consultation with the industry.



Appendix B: System Strength

Appendix B: System Strength

1.1 Operational Experience

SOLAR FACILITY OSCILLATION EVENT

- On July 15, 2021, there was a scheduled outage for 138 kV line 725L (Fort MacLeod 15S – Bowron 674S)
- Mitigation of the next contingency concern (extreme voltage sag in Staveley/Lethbridge area) of losing 138 kV line 172L (North Lethbridge 370S – Chinook 181S)
  - 138 kV line 180L (Fort MacLeod 15S – Granum Tap 604S) was intentionally opened at Fort Macleod 15S substation
- Immediately after the opening, the voltage at Granum 604S substation began to experience two modes of oscillation: a higher-amplitude 0.5 Hz oscillation, and a lower-amplitude 16 Hz oscillation
- Following the event, the AESO's investigation determined that system strength at the solar facility's point of interconnection is significantly reduced when the facility is radially connected
- Post-event analysis and modelling have been inconclusive as to the exact cause of the oscillations, but the hypothesis is that the Power Plant Controller (PPC) voltage regulation control parameters are not appropriately tuned for the weaker system condition when the facility is radially connected to the rest of system
- Based on this hypothesis, a generation test was conducted by the solar facility on April 28, 2022. The test plan was developed to determine whether the PPC is the source of the oscillations and, if possible, to determine new control parameters that are appropriately tuned for the condition when the solar facility is operating under weak system strength
- An analysis of the captured synchro phasor data from the real event and the test at the POI verified that the oscillations during the event were proportional to the facility power output. The amplitude of the oscillations increased as the real power output from the facility increased
- Results of the April 28, 2022 test confirmed PPC to be the source of observed 0.5 Hz oscillations during the July 15, 2021 event; the probability of oscillations was eliminated using different tuning parameters in the PPC implemented on April 28, 2022. Additionally, in collaboration with the inverter manufacturer, it was concluded that the source of the 16 Hz oscillations is the facility inverters as the associated controls were not parameterized for the observed weak operating condition
- The post-disturbance analysis revealed that the operation of the solar facility under weak conditions was not accounted for in the design studies and the provided simulation model does not accurately represent the behaviour of the equipment supplied at the site. Hence, the real-time event was undiscoverable/undetected in the connection studies. Since there was no quick solution available in real-time, the solar facility had to be shut down entirely throughout the outage period to avoid any adverse system impact
- There is an ongoing investigation and additional tests are planned to rectify the 16 Hz oscillation issue. Until the system forensic investigations are complete the facility will remain out of service for the problematic operating conditions

WIND FARM VOLTAGE INSTABILITY EVENT

- On July 25, 2022, voltage oscillations were first noticed in the transmission system in the Medicine Hat planning area during the outage of 240 kV line 964L (Bowmanton 244S – Whitla 251S)
- The post-event analysis revealed the source of oscillations to be the wind farm PPC's voltage control loop
- The AESO in collaboration with the facility owner and equipment manufacturer determined that the PPC is not properly parametrized for operation under the outage condition when either of 240 kV line 964L or 983L is out of service, i.e., the controls were not tuned for a lower system strength condition due to the outage
- As an interim mitigation solution, the facility's AVR was set to reactive power control mode, instead of voltage regulation mode, to minimize the risk of plant tripping and to ensure the reactive power output remains stable during 964L (Bowmanton 244S – Whitla 251S) or 983L (Bowmanton 244S – Whitla 251S) outages
- This was communicated to facility owner in coordination with an upcoming outage, ensuring the original real-time event could be avoided
- A similar mitigation approach was used for the 964L (Bowmanton 244S – Whitla 251S) outage on August 15, 2022
- There is an ongoing investigation in collaboration with the GFO and the equipment manufacturer to rectify the observed issue. Until the investigation is completed an operating procedure is in place to ensure reliable operation of the facility under the described outage conditions

CAP BANK SWITCHING IMPACT ON BURDETT

- A 19 MW solar DER facility is connected to the 25 kV 457LW distribution feeder at the Westfield 107S substation, which is radially fed from the Burdett 368S substation
- Beginning in June 2021, switching of the capacitor banks at the Burdett 368S substation resulted in the disconnection of the solar facility on numerous occasions
- The post-event analysis revealed that following capacitor bank switching at the Burdett 368S substation, prolonged over-voltages on the 138 kV transmission system occurred, exceeding the acceptable operating limits and resulting in disconnection of the solar facility. Low system strength under the outages of 612L or 879L drives higher over-voltages following cap bank switching
- During configurations where the Burdett 368S substation is radially fed from either Fincastle 336S (via 612L) or Bowmanton 244S (via 879L), the solar facility is positioned at the end of the long radial transmission line
- To mitigate potential impacts to the solar facility, two changes were made to the operating procedures outlined in SCP 5-TXMN-15:
  - When both 612L and 879L are in service, the capacitor bank switching at the Burdett 368S substation must now be studied in advance and then coordinated with the DFO who, in turn, is expected to coordinate with the solar facility
  - When either 612L or 879L is out of service and the Burdett 368S substation is being radially supplied, no switching of the capacitor banks at the Burdett 368S substation is allowed, as this results in unacceptably high voltages on the 25 kV distribution system to which the solar facility is connected

1.2 System Strength Assessment

METHODOLOGY

As described previously, SCLs are a measure of how strong the system is at a particular location with respect to perturbation (e.g., load changes, equipment switching) and disturbances (e.g., faults). SCLs across the system can be used as a screening measure to quantify the strength of the system.

There are a number of different methods by which system strength can be quantified. The merits and drawbacks of the different methods were evaluated, and the AESO selected the metrics determined to be the most useful. This assessment used a staged screening approach to identify areas of the AIES subject to system strength shortfalls based on:

- CIGRE brochure[35]
- NERC guidelines
- Other jurisdictional practices

SCREENING APPROACH

The purpose of the screening methodology is to perform short-circuit studies and develop metrics to quantify the system strength applicable to IBRs. There are multiple indices proposed in the NERC reliability guideline[36] and research papers. One of the most basic and commonly applied metrics to identify the relative strength of a power system is SCR. There are multiple SCR-based metrics used in industry to understand the strength of the system when single or multiple IBR connections are considered. Given the SCR metric is more applicable to individual IBR connections and might lead to overly optimistic results, Weighted SCR (WSCR) is used for the condition when multiple IBRs are connected electrically close. In this work, for all studied scenarios, the two indices were used in the calculations depending on the condition.

Per CIGRE's recommendations, IBRs with an index lower than 3 were flagged, as those IBRs could be exposed to weak system conditions. The calculation methodology for the two indices is presented in detail as follows.

Short Circuit Ratio

The SCR metric is the most basic and appropriate when considering a single IBR connecting to a power system. It is calculated at the POI as follows:

$$\mathrm{SCR} = \frac{\mathrm{SCMVA}}{\mathrm{MW^{IBR}}}$$

Where **SCMVA** is the short circuit MVA level at the POI without the current contribution of the IBR and **$\mathbf{MW^{IBR}}$** is the nominal power rating of the IBR at the POI.

This index does not account for the presence of other IBRs or electronic equipment in close electrical proximity to the IBR. When more than one IBR is connected to a specific area in the system, the SCL in the area is shared among these IBRs. Therefore, the system strength experienced by one IBR is significantly less than the calculated SCR. As such, the use of SCR to estimate system strength for an

[35] WG B4.62, "Connection of Wind Farms to Weak AC Networks," CIGRE Technical Brochure 671, December 2016

[36] NERC Reliability Guideline, "Integrating Inverter-Based Resources into Low Short Circuit Strength Systems," December 2017

IBR connected close to other IBRs can lead to overly optimistic results. Other industry metrics include effective short-circuit ratio (ESCR), composite short-circuit ratio (CSCR), and weighted short-circuit ratio (WSCR). In this assessment, the WSCR was utilized.

Weighted Short Circuit Ratio

This metric has been also used by the ERCOT, to study a group of IBRs connected electrically close to each other:

$$\mathrm{WSCR} = \frac{\sum_{\mathrm{i}}^{\mathrm{N}}\left(\mathrm{SCMVA_i} * \mathrm{MW_i^{IBR}}\right)}{\left(\sum_{\mathrm{i}}^{\mathrm{N}} \mathrm{MW_i^{IBR}}\right)^2}$$

Where **SCMVA** is the short circuit capacity at bus $_{\mathrm{I}}$ without current contribution from the IBR connected at bus, **MW**$^{\mathrm{IBR}}$ is the MW output of the IBR connected to bus, and $_{\mathrm{I}}$ is the number of IBRs in the same vicinity.

The above indices are merely indicators to highlight potential areas where low system strength might be a potential issue for IBRs. Lower indices typically increase the likelihood of issues but often don't predict the exact mode of failure or the precise point at which system stability will be compromised. This means that SCR-based metrics should be limited to a high-level screening, and if specific knowledge is required regarding whether a given system will operate as expected, more rigorous study is required, often entailing electromagnetic transient (EMT) tools such as PSCAD. Therefore, there is no pre-determined and commonly used threshold in the industry for the indices; rather, the purpose of the screening process is to gain a high-level understanding of conditions and areas where SCLs could be relatively low in order to plan for detailed EMT studies to determine an acceptable threshold. For example, ERCOT performed a detailed PSCAD study of the ERCOT Panhandle region and determined that a minimum WSCR of 1.5 is appropriate for the connection of IBRs in this area[37].

MODELLING AND ASSUMPTIONS

The 2021 (historical scenario), 2026 and 2031 Renewables and Storage Rush Scenarios from the Net Zero Emissions Pathways Report38 were used for system strength assessments. The operating condition representing the highest penetration levels from IBRs as a percentage of system load served by IBRs, was selected and used for the assessment. This is a more conservative condition from a system strength perspective due to the lower share of SGs in the generation fleet

The 2026 and 2031 study cases include future projects that met the AESO's certainty criteria as of the July 31, 2022 cut-off date

The forecasted capacity assigned to generation resources and energy storage facilities (battery energy storage systems [BESS], pumped hydro, and compressed air energy storage [CAES]) in 2026 and 2031 scenarios were included in the study cases using generic facilities. The geographic location for the generic facilities was selected based on the AESO's latest project list, and market, geographic and technology-driven factors. It is assumed the BESS is operated in grid-following control mode (applicable to a majority of existing utility-scale BESS facilities) and the potential system strength contribution provided by BESS operating in grid-forming control mode is not considered in calculations[39].

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[37] https://www.wingrid.org/wp-content/uploads/2021/08/13-Julia-Matevosyan-ERCOT-Integrating-high-shares-of-IBR.pdf

[38] https://www.aeso.ca/assets/Uploads/net-zero/AESO-Net-Zero-Emissions-Pathways-Report.pdf

[39] The possibility of using Grid Forming BESS as one of potential mitigation solutions for the identified weak areas of AIES will be investigated along other possible solutions in the future detailed studies.

- Different groups of IBRs across the AIES were selected based on electrical distance to adequately capture the interaction possibility
- The assessment was performed for category A normal system condition with all elements in service (N-0)[40]
- Generator reactance of all IBRs was set to a large value prior to the fault analysis in order to avoid the contribution of IBRs to SCLs
- The Central East Transfer-out Transmission Development was considered in the topology for 2026 and 2031 study cases
- A sensitivity scenario with respect to the Provost-to-Edgerton and Nilrem-to-Vermilion Transmission Development was assumed

1.3 Possible Mitigation Solutions

To overcome the reliability challenges tied to system strength shortfalls and to ensure reliable, secure and efficient operation of the power system, it is crucial to explore and identify cost-effective mitigation solutions maintaining minimum system strength requirements.

The AESO categorizes the possible solutions based on the nature of the solutions targeting different reliability issues in the following categories

- **Wires-based |** Adding transmission infrastructure
- **Rules-based |** Modifying or creating ISO rules
- **Market-based |** Modifying existing services or creating new services that can be procured through ancillary service markets or competitive processes, or changing how the energy and ancillary service markets are structured and operated

It should be noted that the possible solutions are not necessarily mutually exclusive, and also a possible solution may be used to address multiple reliability concerns. The solutions the AESO ultimately endorses may be a combination of possible solutions across all these categories.

The potential solutions to mitigate the reliability risks triggered by weak power-system conditions include:

WIRES-BASED SOLUTIONS

Synchronous Condenser

Synchronous condensers provide multifaceted benefits and, if deployed, can be a solution for weak system conditions. Synchronous condensers replicate the bulk of stability functions provided by SGs, including providing the capability to supply fault current, system inertia, voltage support and power-quality improvements. They can be implemented as a transmission asset developed by a regulated entity or procured competitively from a facility owner. This solution becomes more appealing in situations where

[40] The AESO recognizes that transmission outages reduce SCLs; such impacts and other topologies (e.g., category B and category C) will be considered as part of next steps to understand and address reliability concerns of IBRs operations during low system strengths.

SGs are being retired (or considered for retirement). New synchronous condensers can be installed, or the existing unit(s) may be retrofitted to be used as synchronous condensers.

Transmission System Reinforcement

Transmission system reinforcement (e.g., line reconductoring, new transmission circuits, new or larger transformers, series compensation of transmission lines) are effective ways to improve system strength shortfall. This can be achieved by reducing the effective impedance between the weak areas to stronger points in the system. This solution could leverage future system upgrades for additional value.

Flexible Alternating Current Transmission System (FACTS) Devices

FACTS devices such as static volt-ampere reactive (VAR) compensators (SVCs) and static synchronous compensators (STATCOMs) can help control voltages by providing dynamic reactive support. They may be effective in controlling voltage fluctuations under weak system conditions, as well as fault ride-through capability. However, while these devices have fast control loops that can interact with inverter-based resources on weak systems, they are limited in their contribution to fault current (similar to an inverter-based resource) and do not provide any system inertia.

RULE-BASED SOLUTIONS

IBR Plant Control System Changes

Changes to the IBR plant control system(s) may alleviate weak grid issues. Adjustment of control parameters and/or changes to control structures might be used as a measure to avoid the risk of unstable responses driven by weak power system conditions. In other words, parameterizing the power plant controls adaptable with weak operating conditions in the system can be used as a measure to minimize the risk of unstable performance.

Converter Control Changes

Another solution to reduce the reliability risks associated with the performance of IBRs operating under weak system conditions is adjusting power electronic converter controls in conjunction with coordination with upstream plant-level controls. Terminal voltage control or enhancements of the synchronizing algorithms are examples of potential control modifications in weak system conditions. These modifications may require complex engineering efforts but may avoid the need to add equipment to the project.

Reduction in Plant Capacity or Power Output

Reducing the plant capacity or limiting plant output can reduce voltage variation at the point of interconnection as it is driven by the amount of injected power, therefore any sensitivities to active or reactive power output will be reduced by the reduction in plant capacity or output. Restricting plant output under specific operating conditions in real-time may be used as a bridge strategy until a longer-term solution, such as reinforcement or control improvements, can be implemented.

Grid-Forming Inverters

An emerging technology capable of alleviating reliability issues triggered by weak system conditions is grid-forming inverters. In contrast to grid-following inverters[41] used by the majority of existing IBRs to

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[41] Grid-following inverters referred to in this Reliability Roadmap are the dominant and widely deployed technology of IBRs. The grid-forming IBR, which is available for some types of IBRs such as BESS, is a relatively new technology and it does not require a minimum system strength to reliably operate; in fact, they can be also used to improve SCLs as this technology relatively mimics the behaviours of synchronous machines.

interface with the power system, grid-forming inverters are capable of providing most of the critical stability capabilities traditionally provided by SGs. Examples include system-voltage forming, strength support and short-circuit contribution, inertia support, and black-start capability. Grid-forming technology is gaining traction, as it unlocks greater capability to integrate more IBRs into the power system. Some power systems are already deploying this technology as an additional tool to address reliability challenges resulting from the integration of IBRs.

MARKET-BASED SOLUTIONS

Incentivizing Synchronous Generators to be Online

System strength increases when synchronous generators are online. Market-based solutions (such as procuring contracts similar to TMR, expanding broader market-based solutions to exploring market dispatch structure) could be an effective mechanism to provide stronger incentives for SGs to be online.

Levy Variable Interconnection Charges

Alternatively, the AESO could explore which would encourage SGs to choose locations where the system needs strength and discourage IBRs from choosing locations where the system is too weak to allow their reliable operation.

1.4 Planned High-Level Actions

The Reliability Roadmap assessment forecasts AIES system strength over the coming decade. Based on projected conditions, it is clear that the changing generation supply mix, in tandem with decreasing minimum-demand projections driven by emerging DERs, will expose certain areas of the system to higher reliability risks associated with system strength shortfall. In response, the AESO has developed a series of timely actions to enable a seamless transition and preserve the secure and reliable operation of the future power system.

The actions range from improving the AESO's existing IBR interconnection requirements to adopting new technologies and/or market-based solutions to minimize system reliability risks driven by forecasted declining system strength across the AIES. The following proposed actions and potential mitigations are consistent with, and largely reflect the content of the latest industry practices and international guidelines, as well as Alberta's transmission system reliability requirements. The following shows a summary of the proposed actions along with associated urgency.

The planned high-level actions to address system strength challenges are summarized as follows:

- As a near-term priority, improve the existing interconnection requirements of IBRs and update facility control changes to enable additional IBRs to interconnect to the system in weak areas, in addition to reliability improvement across the entire transmission system
- Conduct further evaluation of potential longer-term solutions including market-based solutions, new technologies or infrastructure solutions to determine feasibility and assess cost, market, operational and regulatory considerations

FURTHER ANALYSIS AND MITIGATION INVESTIGATION IN IDENTIFIED WEAK AREAS

The AESO's recent operational experience in the areas identified as weak (described in section 4.3) highlights the need for further analysis to identify and minimize risks to avoid compromising the reliability of the system. The AESO will proceed with the following actions to fully understand the possibility of any adverse impact and adopt mitigation measures:

- Perform EMT assessments focused on selected small groups of resources in weak areas of the AIES (presented in Appendix C) using accurate as-built models to determine the risk of stability issues or adverse system performance
- Work closely with both TFOs and DFOs in the weak areas to conduct an assessment evaluating the impact of system strength shortfall on both the distribution and transmission protection systems as well as power quality
- Investigate whether market-based or wires-based solutions for improving system strength are warranted in areas where IBRs are unable to meet the enhanced requirements (solutions could include must-run contracts, and synchronous condensers or other system assets)

ISO-FACILITATED COORDINATION OF CONTROLS IN IDENTIFIED WEAK AREAS

To address weak system issues, the adjustment, re-tuning, and coordination of controls at the plant or converter level can be deployed quickly and cost-effectively as a non-wires alternative to time-consuming and costly transmission reinforcements. These solutions are contingent upon the availability of high-ability or high-fidelity models that accurately represent the existing equipment at the site and accurate modelling of the studied power system. Upon completion of EMT assessments, the AESO will:

- Confirm that re-tuning of controls can be adopted to alleviate the observed reliability issues
- Facilitate a detailed and coordinated collaboration between all involved stakeholders (manufacturers, GFOs, TFOs and DFOs) for potential inverter control system modifications

INTERCONNECTION, PLANNING AND OPERATION STUDIES

Effective power system analysis is a key enabler for the secure and reliable transformation of the AIES. As the current studies and tools become less effective, given that the fundamental and dynamic characteristics of the system are undergoing a paradigm shift, there is a need to enhance existing tools and processes to ensure that the reliability challenges driven by the changing supply mix are fully understood, assessed and mitigated. The following actions are being assessed:

- Interconnection studies to include a SCR-based screening assessment to identify the risk of reliability issues tied to system strength shortfall while connecting IBRs
- Augment SCR-based screening with a detailed EMT simulation in areas prone to system strength shortfall to further evaluate the following reliability risks and failure modes:
    - Failure to ride through disturbance
    - Converter control interactions
    - Converter control instability
    - Cycling between converter control modes
    - Voltage stability
- The AESO needs to work closely with facility owners and the IBR manufacturers to ensure the connecting facility is studied and its performance is verified for all credible system conditions

PROCESS ENHANCEMENTS

Updating existing interconnection processes and long-term transmission planning in response to increasingly complex reliability challenges while ensuring reliability at a reasonable cost will be critical to maintaining system strength. The generator interconnection process, which primarily focuses on implementing the minimum upgrades required to ensure adequate transmission capacity is available, will need to also address other reliability needs such as protection, controls and equipment capabilities. Long-term transmission planning must have the required information and tools to ensure that system strength challenges are clear, correct and appropriately mitigated to avoid unnecessary and costly transmission upgrades.

Given that the planning and operation of a secure, reliable and cost-effective power system depends on the availability of accurate power system models, the AESO is assessing the following process enhancement actions:

- Develop an integrated generator interconnection and long-term transmission planning process
- Improve the modelling-requirement process to ensure IBR models are accurately structured and parameterized to reasonably represent the supplied equipment such that potential issues are discovered earlier in the interconnection process

TOOLS AND PROCEDURES FOR REAL-TIME OPERATION

The transforming power system is creating unique and complex challenges and will require new operational practices, tools, data, systems, and capabilities. Building systems, tools, and processes that effectively gather, analyze, and present data is critical in improving the ability of operators to make rapid decisions in real time.

From an operational-readiness perspective, for a seamless transition to an evolving power system, a summary of recommended actions is summarized as follows:

- Establish network and system monitoring to enhance visibility to real-time instability and power system security impacts
- Build real-time and forward-looking stability, adequacy and risk-assessment tools for situational awareness and proactive decision-making with the ability to detect oscillations and to forecast system conditions
- Implement automated, accurate data-collection processes for post-event analysis and operation studies
- Conduct regular system inertia and system strength studies to identify potential upcoming real-time operation concerns to mitigate in a timely manner
- Integrate SCR analysis into assessments throughout AIES
- Integrate EMT studies into assessments

MODELLING REQUIREMENTS

Accurate steady-state and dynamic simulation models play a crucial role in maintaining the reliability and security of the power system at a reasonable cost. Current IBR modelling is limited to phasor domain stability studies, which are valuable for planning, operation and interconnection studies but might not adequately capture many stability and reliability challenges. To fulfil these requirements, the current models will need to be supplemented with additional modelling capabilities. Following is an action plan to improve modelling capabilities:

- Establish mandatory requirements for GFOs to provide validated phasor domain and EMT IBR models along with all supporting documentation, including:
  - Model descriptions

- Single-line diagrams
- As-built inverter level control and protection settings
- Plant-level control and protection settings

- Improve the modelling process to clearly articulate study types and requisite supporting (e.g., dynamic, steady-state, short-circuit, and EMT) model requirements as applicable
- Supplement study models with post-commissioning disturbance monitoring to further improve the quality of the model and capture ongoing adjustment of model parameters over the lifetime of the equipment
- Implement a feedback loop from the real-time operation to ensure model accuracy; inconsistencies between expected and actual plant performance during real-time events can reveal potential model parameterization issues that need to be captured

PERFORMANCE REQUIREMENTS FOR IBRS

It is necessary to revisit the existing performance requirements and unique characteristics of IBRs to meet the evolving needs of an increasingly complex power system. Significant advances have been made to determine appropriate interconnection capability and performance criteria, including recent Institute of Electrical and Electronic Engineers (IEEE) standards publications[42]. The following actions are recommended to enable additional IBRs to interconnect to the system in weak areas but will also improve reliability across the entire transmission system:

- Develop performance requirements that leverage new inverter technology capabilities (e.g., grid-forming inverters)
- Review existing IBR performance requirements to identify gaps to best practices, determine appropriate actions and implement requisite change to the following:
  - Voltage and frequency ride-through
  - Active power control
  - Reactive power control
  - Dynamic active power support under abnormal frequency conditions
  - Dynamic voltage support under abnormal voltage conditions
  - Power quality
  - Negative sequence current injection
  - System protection

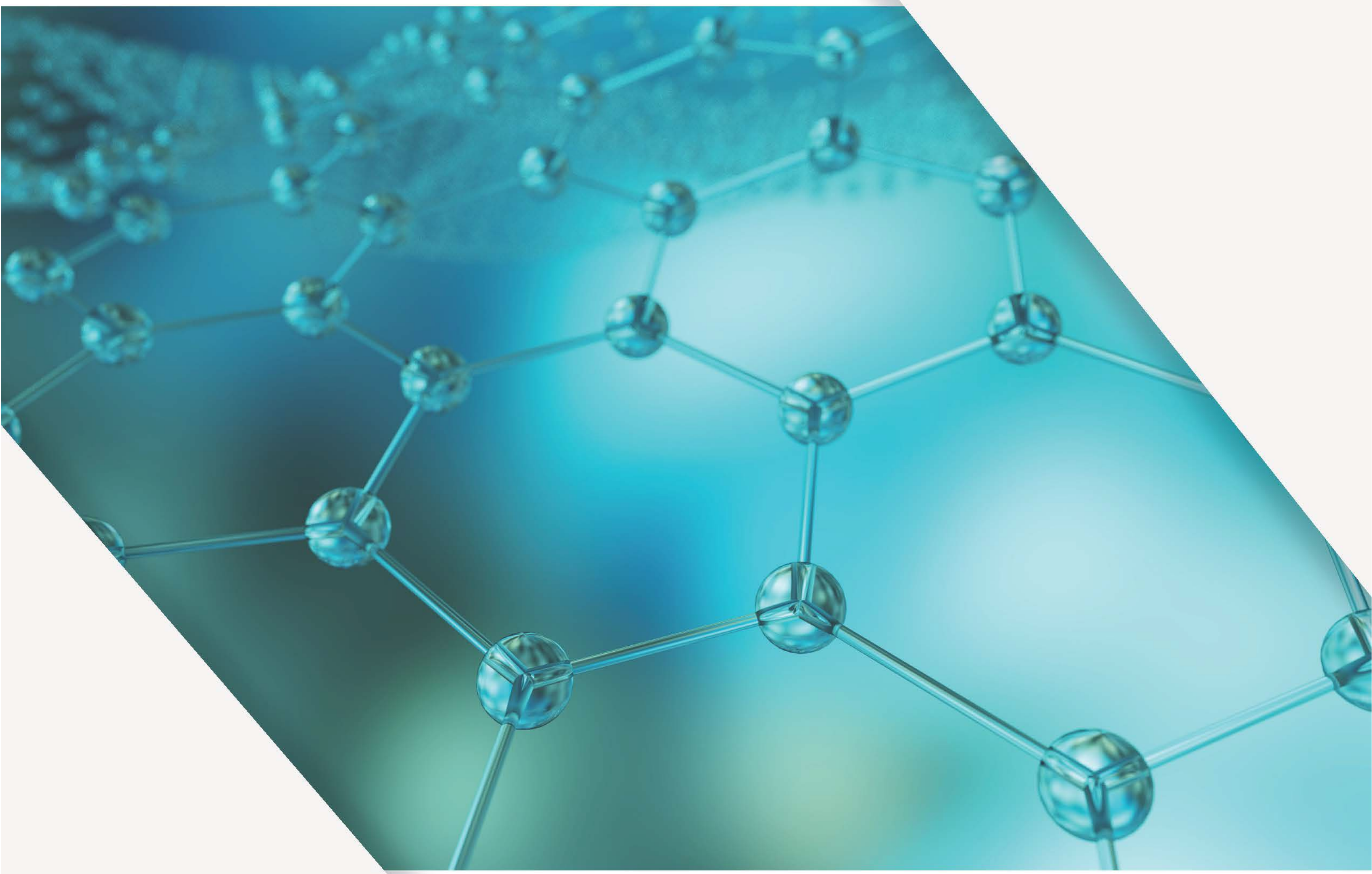
PROTECTION SYSTEM REQUIREMENTS

As more IBRs are interconnected, the protection elements and settings used in the transmission line protection systems may need to be changed to maintain reliability and security. New research is providing recommendations on which IBR protection elements to use, and which to avoid, as well as potential setting optimizations.

[42] "IEEE 2800-2022," IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems."

The AESO will need to engage with TFOs, DFOs and GFOs to assess existing protection designs, standard settings, and hardware when integrating IBRs into weak areas of the system. Transmission line protection system in these areas of low system strength with high IBR penetration likely need to be monitored and studied as necessary to ensure their hardware and settings are still reliable and secure. To improve AIES transmission protection systems the following actions are recommended:

- New protection technologies (e.g., adapted distance protection algorithms, time domain protection functions, wind area monitoring protection, and control systems) need to take into account system specific conditions to be effective
- Creation of an Alberta protection workgroup, including all TFOs, to gather and share IBR protection system expertise and knowledge
- Monitor impact of IBR penetration on protection systems and determine long-term strategy for addressing weaker areas of the AIES



Appendix C: Flexibility Capability

Appendix C: Flexibility Capability

1.1 Operational Experience

ASSET COMMITMENT

Wind forecast error | On February 5, 2022, approximately 1,000 MW of wind generation ramped down over a span of two hours, remained low for approximately two hours during the evening peak hours, and then ramped back up to the original production level. Typically, the wind forecast reasonably captures the timing and magnitude of large wind ramps, but in this case, the optimal forecast underestimated the magnitude of reduction to be approximately 450 MW prior to the event. The ramp down in wind generation by approximately 550 MW more than the forecasted reduction pushed the energy market dispatch to nearly the top of the merit order and caused energy prices to settle near the energy market price cap. As the duration of the temporary wind reduction was only several hours, a more accurate wind forecast far enough in advance may not have averted high energy prices as long lead-time assets may not have cycled on due to the short period of time.

AREA CONTROL ERROR

Observations on the wind and solar forecast | The variability of wind and solar assets, along with the quality of short-term wind and solar forecasts, can make the real-time balancing of supply and demand challenging. While statistical analysis of forecast errors can quantify the accuracy of short-term forecasts (refer to Forecast Uncertainty in Appendix C, section 1.3) they do not capture the broader impacts on operational decision-making.

Observations on directives | Recently some spinning reserve resources have been delaying their response to nearly the maximum allowed before starting to ramp. While this observation is not within the scope of the flexibility assessment per se, it is analogous to dispatching the energy market for ramping. Dispatches for ramping start out as an ordinary dispatch, where the dispatched asset would contribute to the ramping needs. When the asset is no longer required, the dispatch would return to the pre-ramping level. Delaying the response to the directive would not only negatively affect the ramping capability of the system, but it would also slow down the response to other dispatches.

1.2 Flexibility Capability Assessment

The AESO has previously assessed forecast net demand variability and whether the electric system has sufficient flexibility in the *Dispatchable Renewables and Energy Storage* report[43] published in May 2018, the *2020 System Flexibility Assessment*[44] published in July 2020, and the *2022 System Flexibility Assessment*[45] published in June 2022.

This assessment amends the *2022 System Flexibility Assessment* with content from the *AESO Net-Zero Emissions Pathways*[46] published in June 2022. The amendment used a market and dispatch simulation methodology similar to that of the *2022 System Flexibility Assessment* with some exceptions, notably:

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

[44] Available at https://www.aeso.ca/assets/Uploads/AESO-2020-System-Flexibility-Assessment-FINAL-jul-17.pdf

[45] Available at https://www.aeso.ca/assets/2022-System-Flexibility-Assessment.pdf

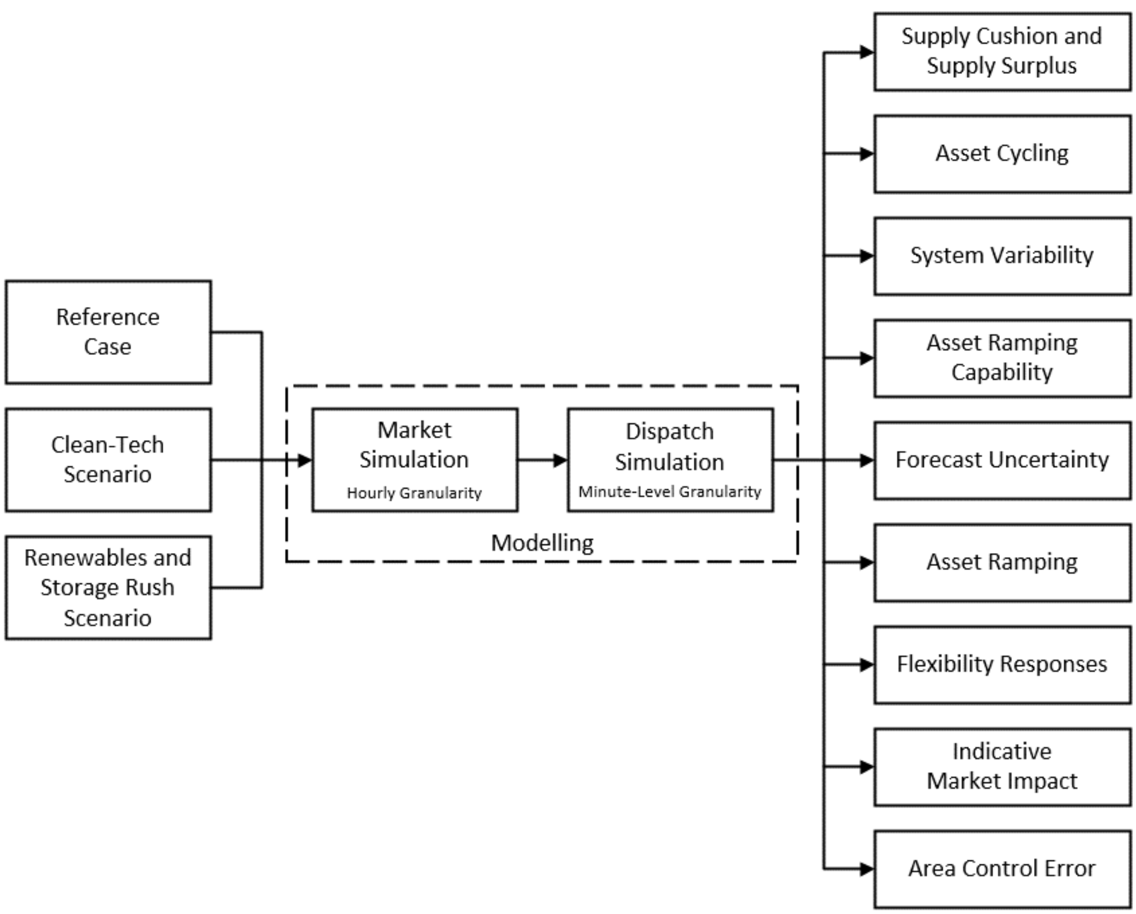
[46] Available at https://www.aeso.ca/assets/Uploads/net-zero/AESO-Net-Zero-Emissions-Pathways-Report.pdf

- Inclusion of greater amounts of energy storage assets and small distributed energy resources, consistent with scenarios in the *AESO Net-Zero Emissions Pathways*
- Inclusion of greater amounts of wind and solar generating assets, also consistent with scenarios in the *AESO Net-Zero Emissions Pathways*
- Separate modelling of transportation load driver
- Exclusion of operational simulation results as these have moved to their respective sections within the Reliability Roadmap

With the inclusion of the *AESO Net-Zero Emissions Pathways*, the AESO used three scenarios to simulate the ability of the electric system to balance supply and demand in 10-minute intervals over a 10-year forecast period. The Reference Case, Clean-Tech Scenario, and Renewables and Storage Rush Scenario described in section 2.4 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.

Figure 22 illustrates the analytical approach used for the system flexibility assessment.

Figure 22: System flexibility analytical approach



HOURLY MARKET SIMULATION

Aurora market modelling software was used to simulate the supply and demand characteristics of the Reference Case, Clean-Tech Scenario and Renewables and Storage Rush 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 behaviour 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.

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
- 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

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
- Gas-fired steam (referred to as coal-to-gas conversion in the 2021 LTO and AESO Net-Zero Report) 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
  - For the Renewables and Storage Rush Scenario, transportation load was modelled by hour with adjustments for the season (winter and summer) and day type (weekday and weekend)
- Small distributed energy resources of less than 5 MW were included as an offset, using resource-specific profiles, within the 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. The volumes applied over the forecast period were equal to the currently procured volumes
- 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
  - System Controller dispatch was modelled using a proactive dispatch strategy to align with system conditions expected in 10-minutes (for example, System Controllers are dispatching at time HH:10 for system conditions expected at time HH:20)
- 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 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 the 2022 System Flexibility Assessment. The simulation assumptions were not updated for this system flexibility assessment to allow for a direct comparison between the 2022 System Flexibility Assessment and the amended results. 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.

1.3 Market and Dispatch Simulation Results

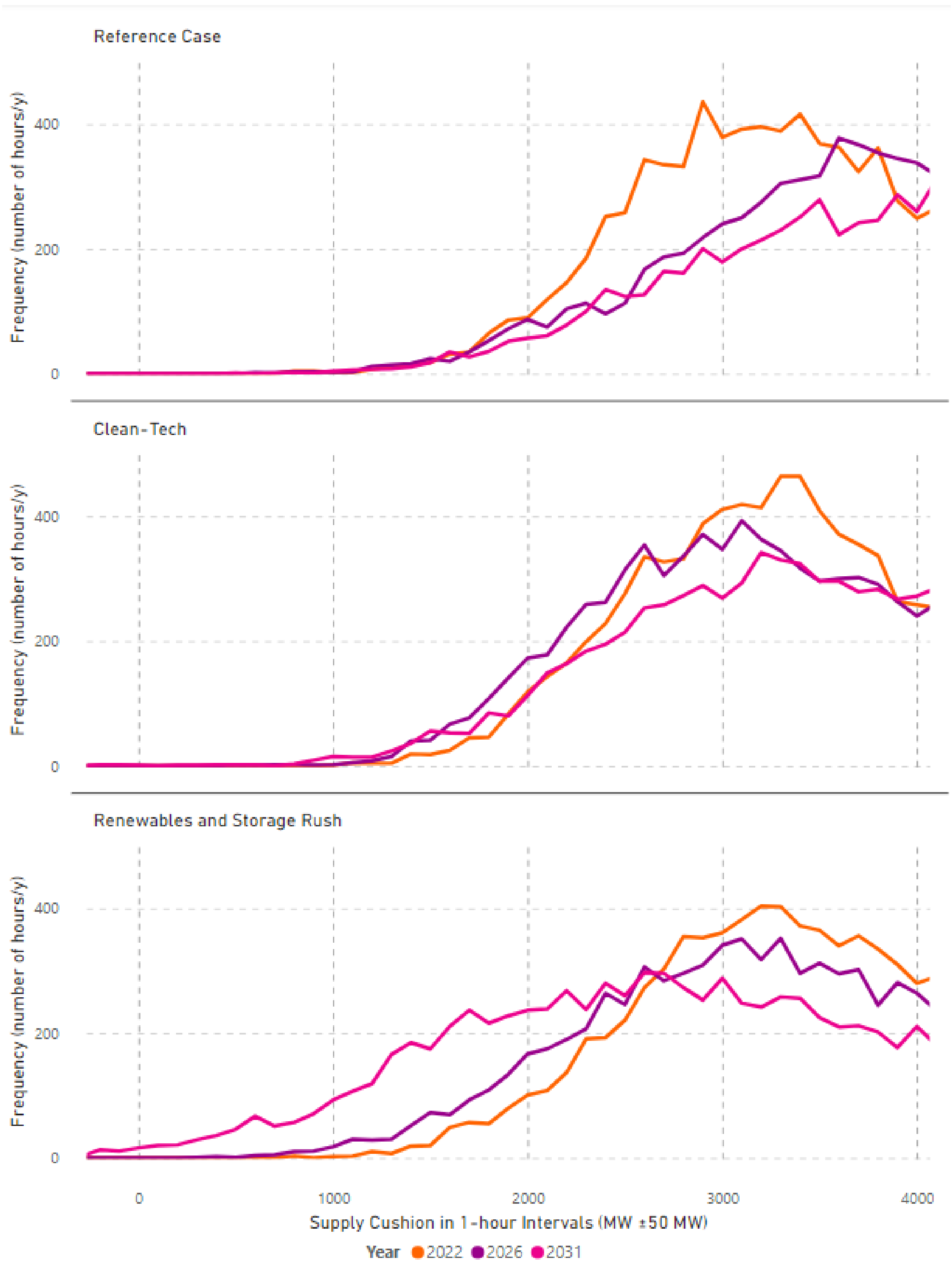
SUPPLY CUSHION

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 the flexibility assessment, supply cushion is calculated as available generation capacity, including variable generation and operating reserve, plus available intertie 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 23, the horizontal axis shows the amount of supply cushion, in MW, in every one-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 the Reference Case, Clean-Tech Scenario, and Renewables and Storage Rush Scenario.

Figure 23: Supply cushion in 1-hour intervals by scenario

Including operating reserve plus available intertie import capacity, minus load demand) in 1-hour intervals by 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. However, the frequency distribution also illustrates a lower supply cushion in many hours in later years compared to earlier years of the forecast period in the Renewables and Storage Rush Scenario, reflecting the greater proportion of generation capacity from renewable resources, which gives rise to more frequent hours with low production from renewable resources. To focus on the frequency of hours with low supply cushion, Figure 24 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 4,900 hours in 2031
- In the **Clean-Tech Scenario**, about 2,000 hours in 2022 and about 3,100 hours in 2031
- In the **Renewables and Storage Rush Scenario**, about 2,400 hours in 2022 and about 1,300 hours in 2031

Supply cushion is also more frequently critically low in later years of the Clean-Tech Scenario and Renewables and Storage Rush Scenario compared to the Reference Case. For example, supply cushion falls below 500 MW zero times in 2022 for all the scenarios, but increases to:

- 1 hour by 2031 in the **Reference Case**
- 13 hours by 2031 in the **Clean-Tech Scenario**
- 172 hours by 2031 in the **Renewables and Storage Rush Scenario**

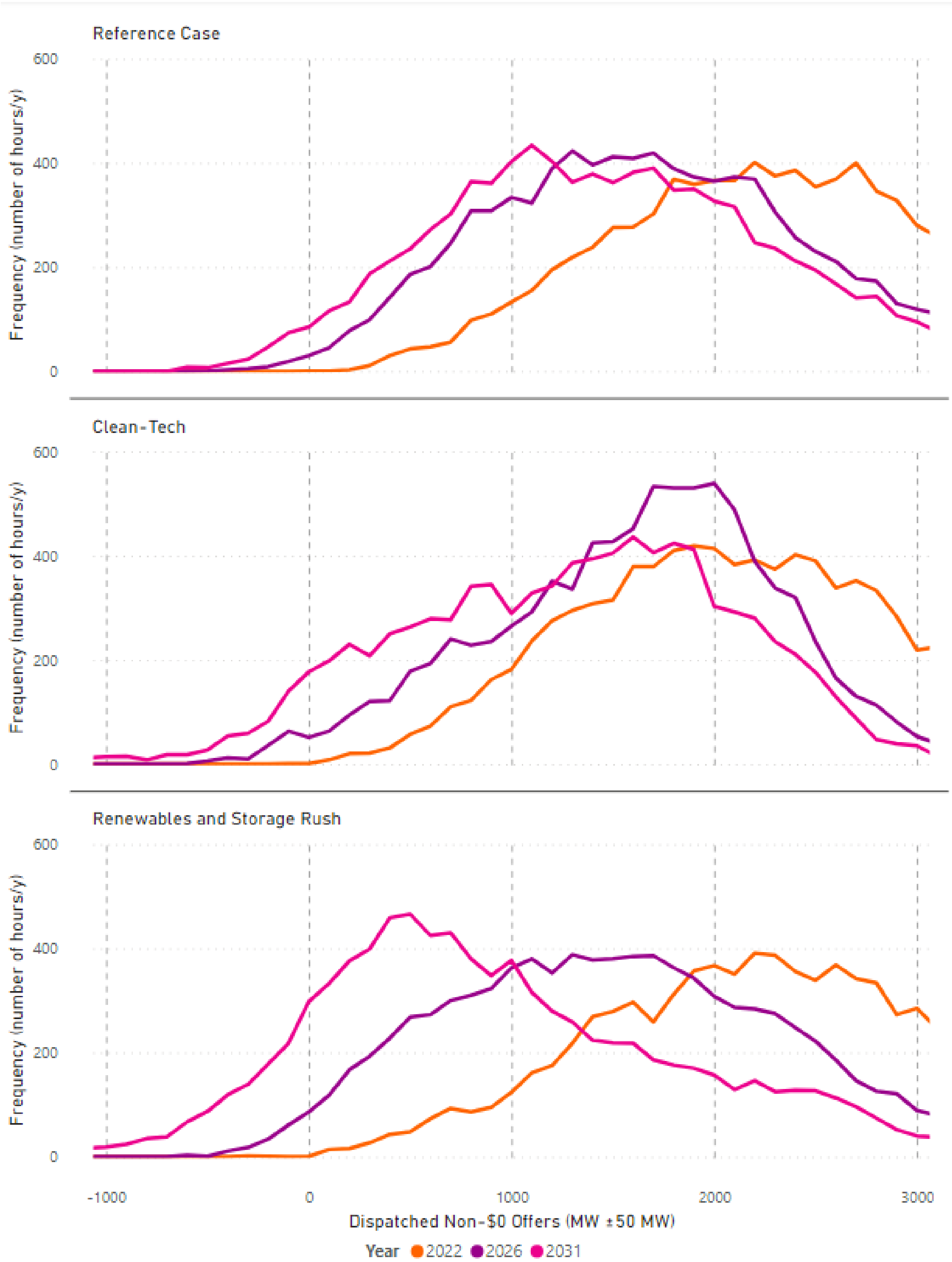
The increasing frequency of hours with very low supply cushion in the Clean-Tech Scenario and Renewables and Storage Rush Scenario indicates increasing risk that System Controllers may be required to take emergency action to ensure system stability if supply cushion falls to zero due to forced outages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

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 24 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, Clean-Tech Scenario, and Renewables and Storage Rush Scenario. The horizontal axis shows the amount of dispatched generation capacity, in MW, which 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.

Figure 24: Dispatched generation capacity offered above $0/MWh in 1-hour intervals by scenario



The frequency distribution illustrates that supply surplus occurs in more hours in later years compared to earlier years of the forecast period in the Reference Case, Clean-Tech Scenario, and Renewables and Storage Rush Scenario, which is attributed to the larger capacity of variable generation. For example, the number of supply surplus hours increases across the forecast period by:

- In the **Reference Case**, 0 hours in 2022 to 215 hours in 2031.
- In the **Clean-Tech Scenario**, 2 hours in 2022 to 600 hours in 2031.
- In the **Renewables and Storage Rush Scenario**, 3 hours in 2022 to 1,187 hours in 2031

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.

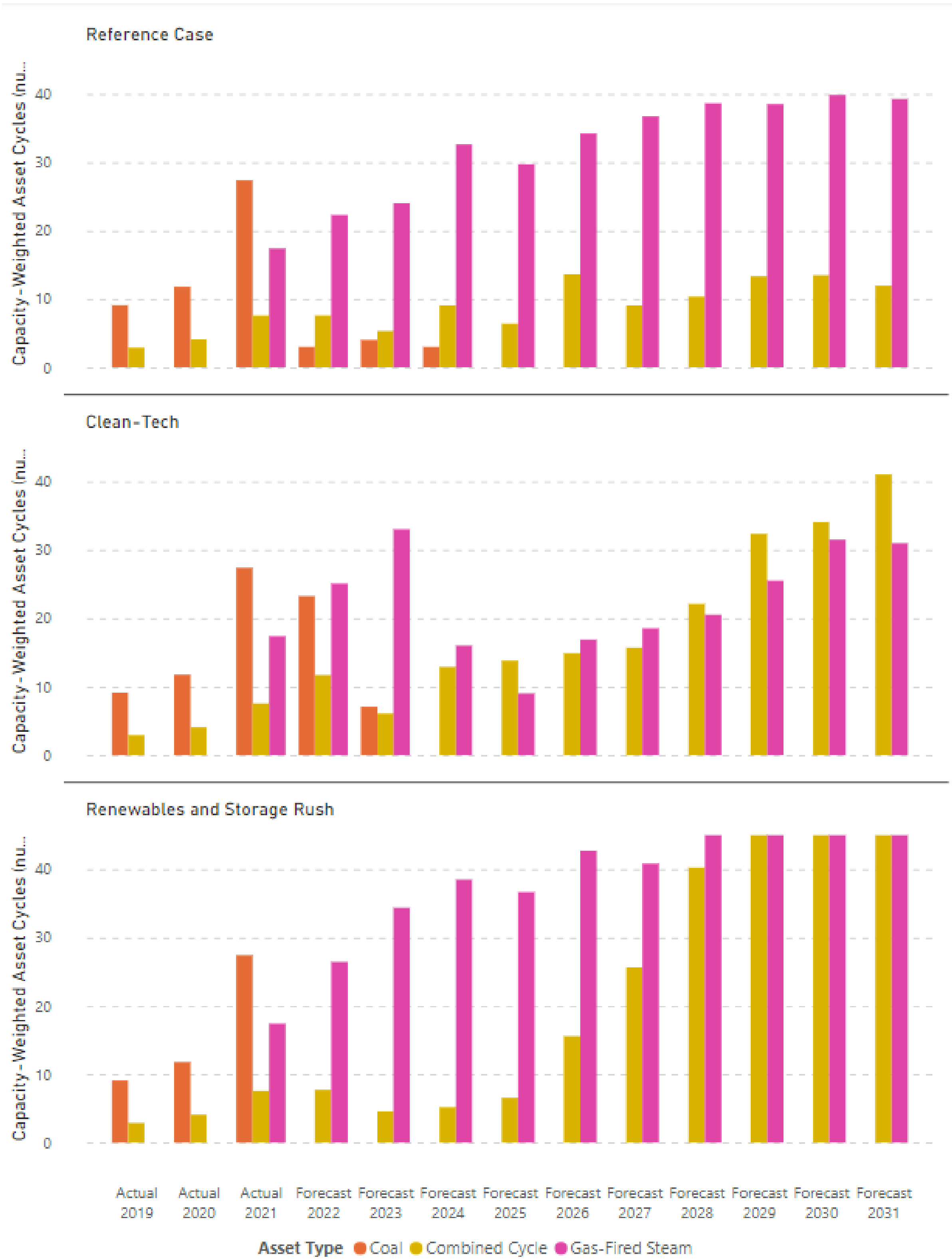
ASSET ON/OFF CYCLING

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 25 presents the average on/off cycles for baseload generating assets weighted by maximum capability, over the forecast period for the Reference Case, Clean-Tech Scenario, and Renewables and Storage Rush 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. Over the forecast period in the Renewables and Storage Rush Scenario, on/off cycling increases for gas-fired steam-generating assets first, followed by increased cycling for combined-cycle generating assets. These changes are attributed to interactions that affect offers in the markets differently for different generation technologies. Compared to the Reference Case, the later years of the Clean-Tech Scenario have significantly larger combined cycle capacity and significantly smaller gas-fired steam capacity, while the later years of the Renewables and Storage Rush Scenario have significantly larger wind, solar and energy storage capacity and significantly smaller gas-fired steam capacity.

Figure 25: Average number of on/off cycles per generating asset by technology by scenario



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, which is attributable to AIL, to variable generation, or to net demand (which is AIL 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 a 10-minute proactive dispatch occurring on the 10-minute marks during an hour, net demand variability over 10-minute intervals was primarily addressed in the simulations through energy market dispatch up or down the merit order. Remaining variability was addressed 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 addressed in the simulation through energy market dispatch up or down the merit order.

Figure 30 provides the size and frequency of 10-minute ramps of AIL, variable generation, and net demand from the simulations for 2022, 2026, and 2031 in the Reference Case, Clean-Tech Scenario and Renewables and Storage Rush Scenario. Figure 27 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 AIL, variable generation, and net demand
- In later years in the Reference Case, Clean-Tech Scenario and Renewables and Storage Rush Scenario
- To a greater extent in:
  - The Renewables and Storage Rush Scenario compared to the Clean-Tech Scenario
  - 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 **AIL**, the larger capacity of small distributed energy resources of less than 5 MW which were included as an offset within the load profile data in:
  - Later years of the forecast period
  - The Clean-Tech Scenario
  - The Renewables and Storage Rush Scenario
- For **variable generation**, the larger capacity of variable generation in:
  - Later years of the forecast period
  - The Clean-Tech Scenario
  - The Renewables and Storage Rush Scenario
- For **net demand**, the increase in frequency of larger variable generation ramps, combined with the increase in frequency of larger load ramps

Figure 26: Distribution of 10-minute ramps for load, variable generation, and net demand by scenario

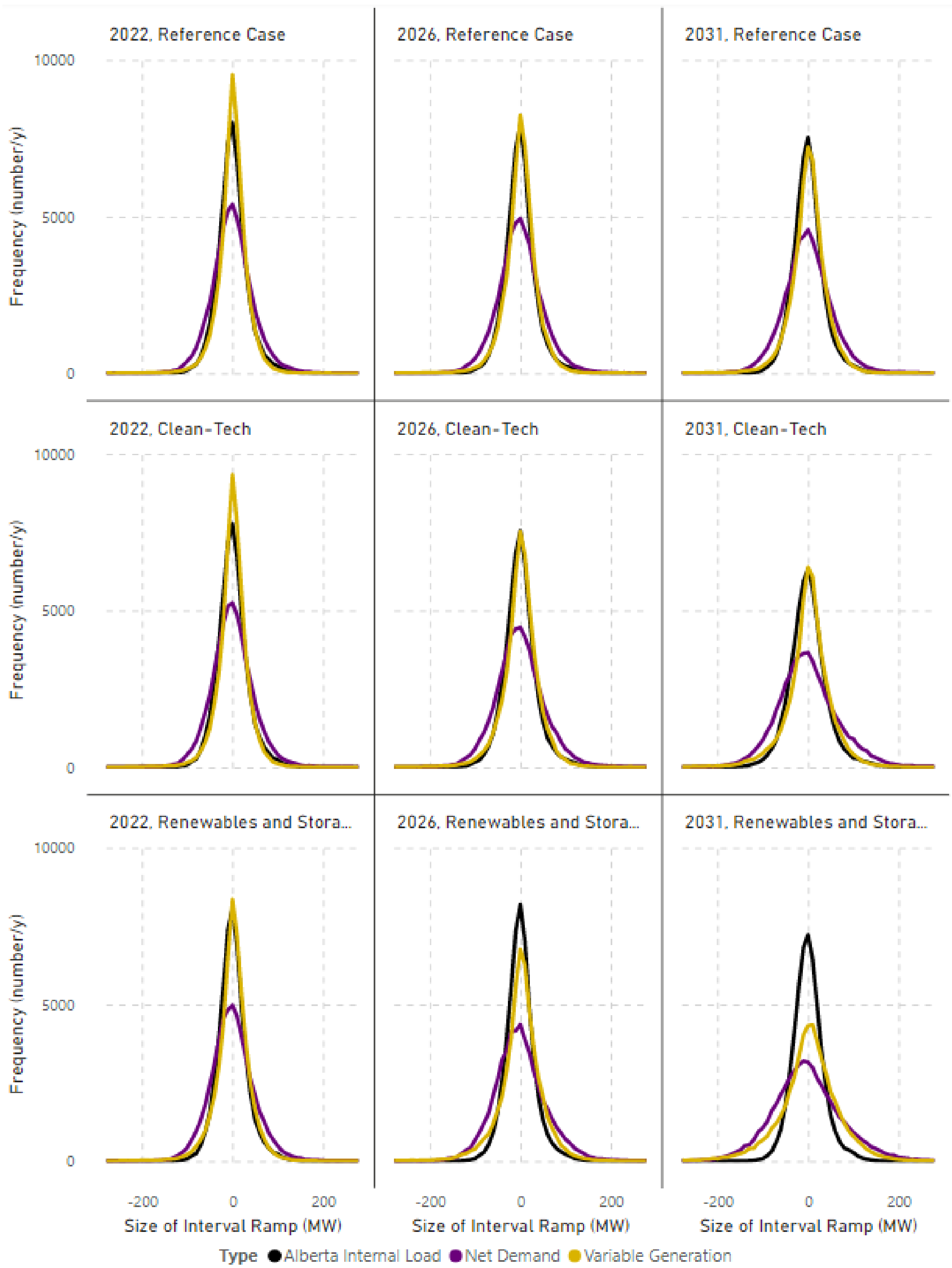


Figure 27: Distribution of 60-minute ramps for load, variable generation, and net demand by scenario

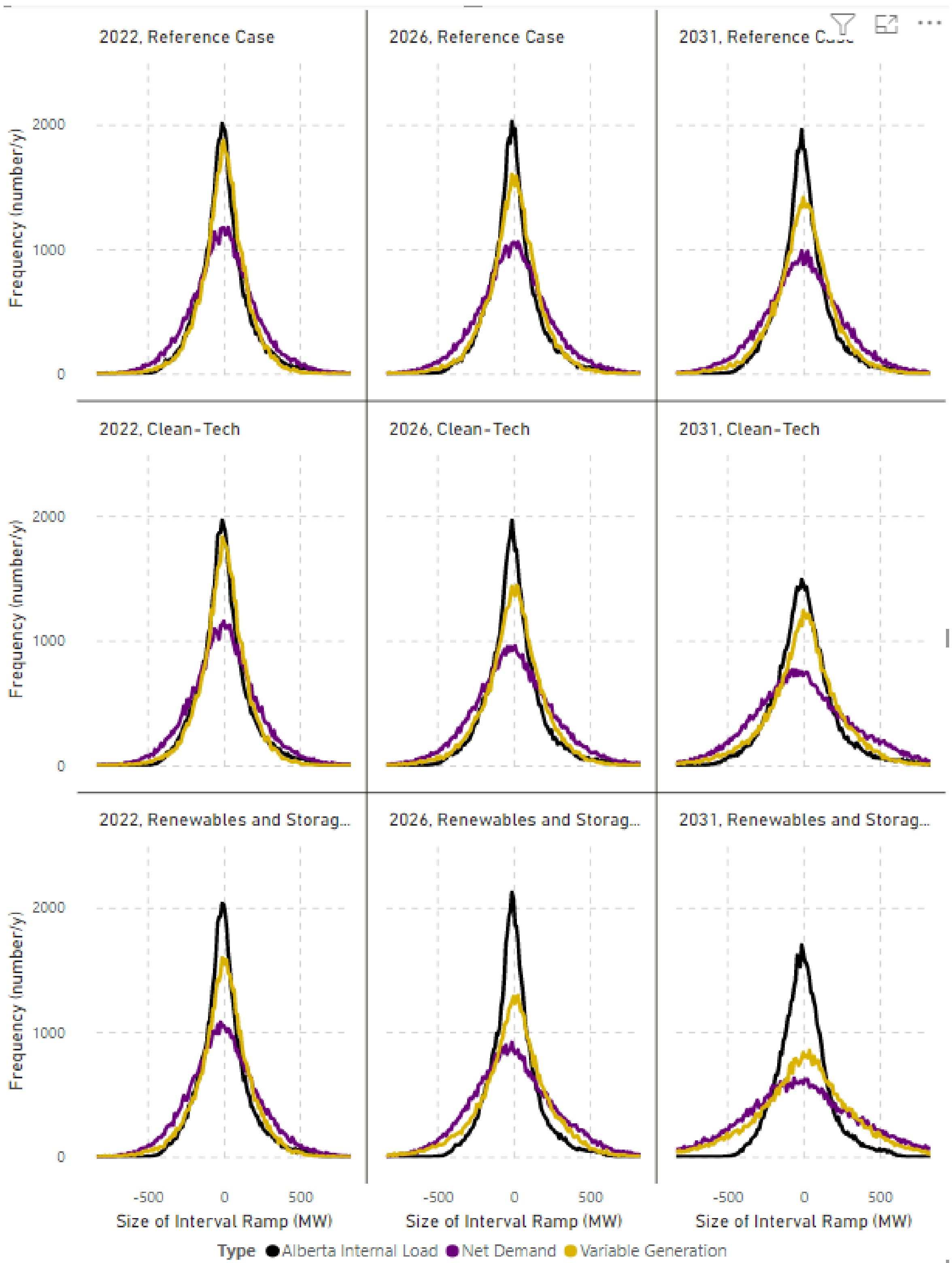


Table 9: Average size and frequency of large 10-minute and 60-minute ramps for load, variable generation, and net demand by scenario

		Alberta Internal Load			Variable Generation			Net Demand		
		2022	2026	2031	2022	2026	2031	2022	2026	2031
Large Short Ramps (±50 MW or more over 10 minutes, starting every 10 minutes during year)										
Reference Case	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 year)	12.0%	12.6%	13.1%	10.8%	13.8%	17.0%	24.4%	27.8%	31.1%
Clean-Tech Scenario	Average Size (MW)	70	74	77	78	82	89	79	85	93
	Frequency (intervals/y)	6,341	7,381	9,989	5,866	9,108	12,824	13,153	16,695	21,824
	Frequency (% of year)	12.1%	14.0%	19.0%	11.2%	17.3%	24.4%	25.0%	31.8%	41.5%
Renewables and Storage Rush Scenario	Average Size (MW)	70	71	71	80	87	101	81	87	104
	Frequency (intervals/y)	6,017	6,055	6,681	7,830	11,955	19,613	14,269	18,123	25,129
	Frequency (% of year)	11.4%	11.5%	12.7%	14.9%	22.7%	37.3%	27.1%	34.5%	47.8%

		Alberta Internal Load			Variable Generation			Net Demand		
		2022	2026	2031	2022	2026	2031	2022	2026	2031
Large Long Ramps (±100 MW or more over 60 minutes, starting every 10 minutes during year)										
Reference Case	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 year)	43.2%	43.6%	44.8%	43.5%	49.1%	53.6%	59.6%	63.1%	66.4%
Clean-Tech Scenario	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 year)	43.8%	45.3%	51.9%	44.1%	52.8%	59.2%	60.4%	66.5%	73.0%
Renewables and Storage Rush Scenario	Average Size (MW)	208	208	207	219	259	338	253	289	380
	Frequency (intervals/y)	22,330	22,100	24,825	25,825	30,303	37,160	33,029	36,140	40,887
	Frequency (% of year)	42.5%	42.1%	47.2%	49.1%	57.7%	70.7%	62.8%	68.8%	77.8%

		Alberta Internal Load			Variable Generation			Net Demand		
		2022	2026	2031	2022	2026	2031	2022	2026	2031
Very Large Long Ramps (±500 MW or more over 60 minutes, starting every 10 minutes during year)										
Reference Case	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 year)	0.9%	1.1%	1.1%	0.6%	1.3%	2.3%	2.9%	4.5%	6.1%
Clean-Tech Scenario	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 year)	0.8%	1.5%	2.7%	0.6%	2.1%	5.0%	3.0%	5.9%	12.6%
Renewables and Storage Rush Scenario	Average Size (MW)	546	555	554	585	625	698	599	623	713
	Frequency (intervals/y)	403	485	524	708	2,235	7,058	1,903	3,783	10,247
	Frequency (% of year)	0.8%	0.9%	1.0%	1.3%	4.3%	13.4%	3.6%	7.2%	19.5%

For the 10-minute ramps of net demand in the Reference Case illustrated in Figure 12, 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. In the Renewables and Storage Rush Scenario, the average size of large ramps (of at least ±50 MW) increases by about 28 per cent over the forecast period, and the frequency of those large ramps increases by about 76 per cent. The increase in size and frequency of large 10-minute ramps indicates increasing need for dispatchable generation capacity, regulating reserve and instantaneous interchange to respond to net demand variability in later years, in the Clean-Tech Scenario, and in the Renewables and Storage Rush Scenario.

For the 60-minute ramps of net demand in the Reference Case illustrated in Figure 27, the average size of very large ramps up and down (of at least ±500 MW) increases by about 5 per cent over the forecast period, and the frequency of those large ramps increases by about 110 per cent. In the Clean-Tech Scenario, the average size of very large ramps (of at least ±500 MW) increases by about 9 per cent over the forecast period, and the frequency of those very large ramps increases by about 315 per cent. In the Renewables and Storage Rush Scenario, the average size of very large ramps (of at least ±500 MW) increases by about 19 per cent over the forecast period, and the frequency of those very large ramps increases by about 438 per cent. 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, in the Clean-Tech Scenario, and in the Renewables and Storage Rush 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 renewables generation and the small distributed energy resources in both the Reference Case, Clean-Tech Scenario and Renewables and Storage Rush Scenario

- Improved solar generation profile used for the simulations, as discussed previously in Appendix C, section 1.2

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.

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 Ramp Distribution (Appendix C, section 1.3), 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 28 illustrates the average ramp rates of the dispatchable generation capacity simulated in the Reference Case, Clean-Tech Scenario, and Renewables and Storage Rush 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 28 indicate the total generating capacity, in MW, in each of four ramp rate categories:

- **Fast ramping |** capable of increases of more than four per cent of maximum capability per minute (primarily some cogeneration, simple cycle generation, and hydro generation)
- **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)
- **Ramp rate not modelled |** ramping capability from energy storage was not modelled as energy storage assets were modelled with charge and discharge profiles based on prices in the energy market simulation. This is a conservative assumption that causes the ramping capability of the system as a whole to be underestimated

Fast ramping generating capacity increases moderately over the forecast period in the Reference Case, Clean-Tech Scenario, and Renewables and Storage Rush Scenario. The increase results primarily from fast-ramping cogeneration 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 Figure 26 and Figure 27.

Medium ramping generating capacity increases moderately over the forecast period in the Reference Case and Renewables and Storage Rush Scenario 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 and Renewables and Storage Rush Scenario. The decrease in the Clean-Tech Scenario and Renewables and Storage Rush 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 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 28: Ramp rates of dispatchable generation by scenario

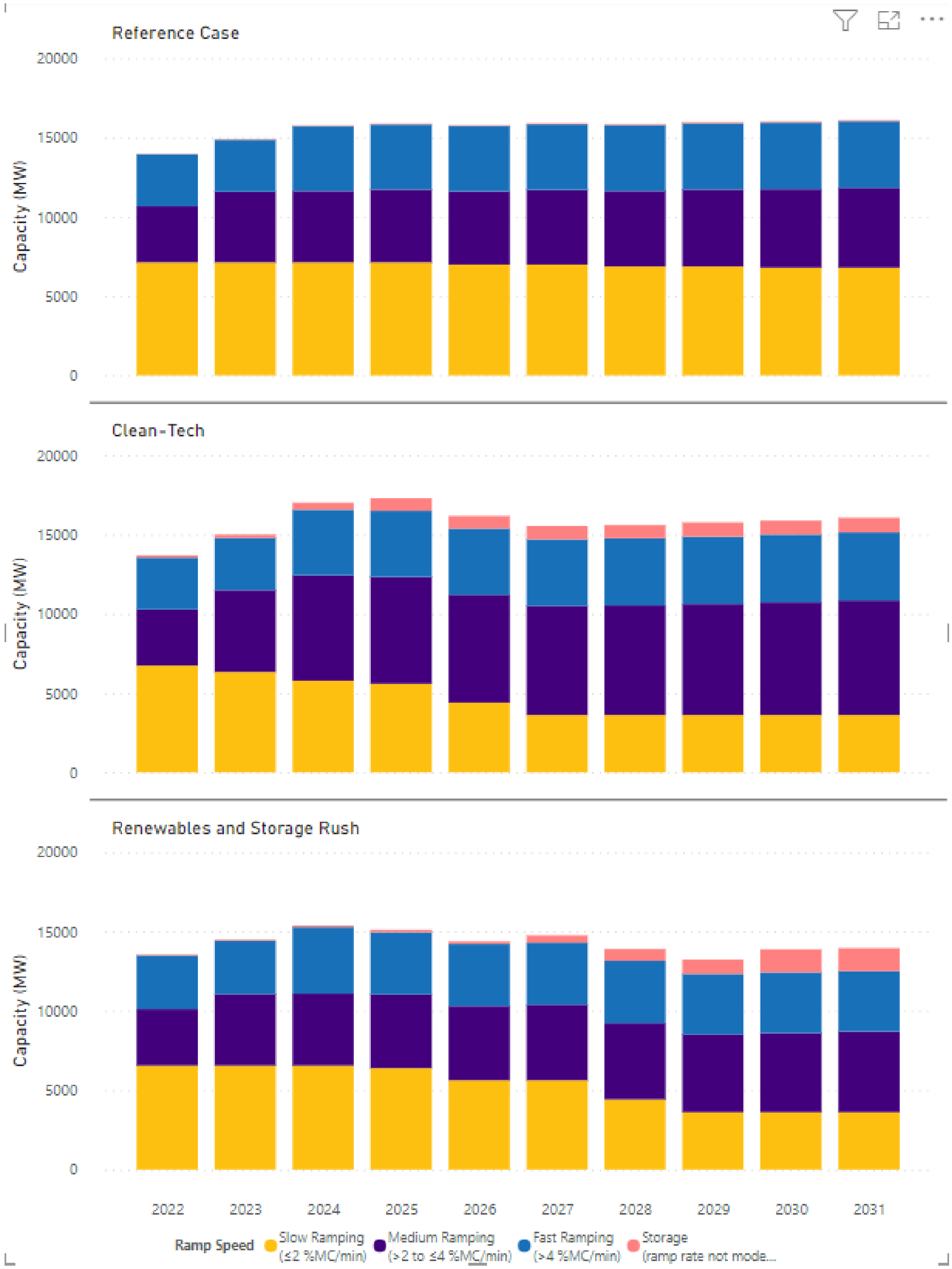


Figure 29: Average response delay of dispatchable generation by scenario

Figure 29 illustrates the average response delay of the dispatchable generation capacity included in the Reference Case, Clean-Tech Scenario, and Renewables and Storage Rush 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 recently observed characteristics by generation technology.

For the Reference Case and Clean-Tech Scenario, the 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. For the Renewables and Storage Rush Scenario, the average response delay materially decreases by about twenty-seven to thirty-two per cent. The stable and decreasing response delay will allow for the predictable dispatch of generation to respond to the larger net demand ramps that occur with greater frequency over the forecast period in all scenarios.

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 intervals 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), where the simulated wind generation ramp at the beginning of a 10-minute interval was extended to the end of the upcoming interval. The simulated wind generation reflected the wind production modelled as described in Appendix C, section 1.2.

In the dispatch simulation, the forecast solar generation reflected a constant cloud coverage, where the ratio of the simulated solar generation to the clear-sky potential solar generation at the beginning of a 10-minute interval was held constant to the end of the upcoming interval. The simulated solar generation reflected the solar production modelled as described in Appendix C, section 1.2.

Figure 30 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, Clean-Tech Scenario, and Renewables and Storage Rush Scenario. Figure 30 also includes the distribution of the 10-minute-ahead solar generation constant cloud coverage forecast error over all hours in 2022, 2026, and 2031 for the Renewables and Storage Rush Scenario (solar generation forecast error was not assessed in the Reference Case or Clean-Tech Scenario). The error at a given 10-minute interval is defined as the 10-minute-ahead forecast of wind or solar generation minus the actual generation for that interval. The distribution of wind generation forecast error indicates increasing frequency of larger errors in all scenarios. The distribution of solar generation forecast error indicates increasing frequency of larger errors in the Renewables and Storage Rush Scenario.

Figure 30: Distribution of 10-minute-ahead wind and solar generation forecast error by scenario

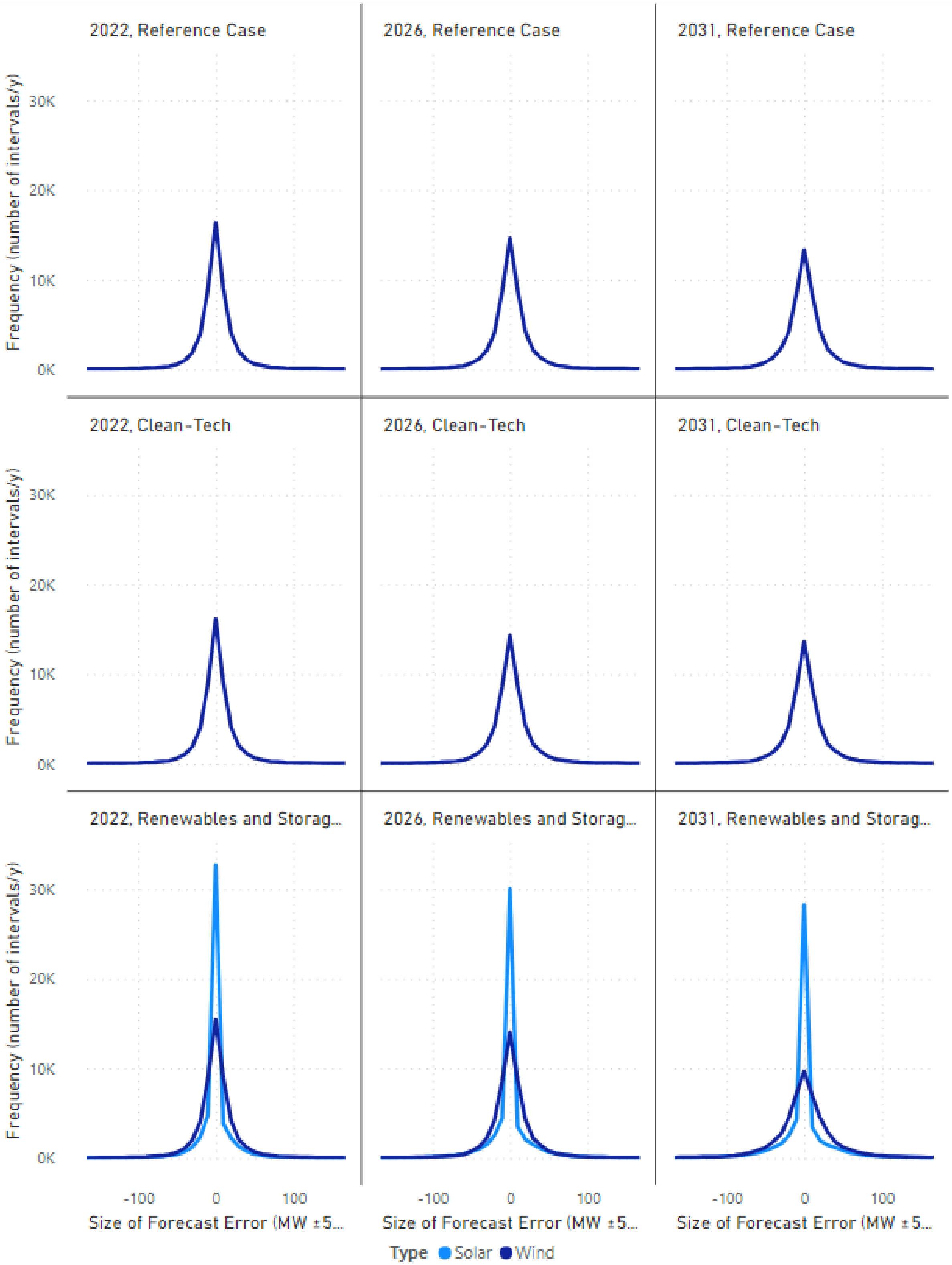


Table 10 summarizes the average size and frequency of large 10-minute forecast error for wind and solar in all scenarios.

Table 10: Average size and frequency of large 10-minute forecast errors for wind and solar by scenario

		Wind Forecast			Solar Forecast		
		2022	2026	2031	2022	2026	2031
Large Errors (±50 MW or more over 10 minutes, starting every 10 minutes during year)							
Reference Case	Average Size (MW)	102	108	115	N/A		
	Frequency (intervals/y)	3,730	4,607	5,432			
	Frequency (% of year)	7.1%	8.8%	10.3%			
Clean-Tech Scenario	Average Size (MW)	102	110	114	N/A		
	Frequency (intervals/y)	3,844	4,798	5,238			
	Frequency (% of year)	7.3%	9.1%	10.0%			
Renewables and Storage Rush Scenario	Average Size (MW)	106	112	126	82	89	95
	Frequency (intervals/y)	4,168	4,929	9,283	2,353	4,285	5,922
	Frequency (% of year)	7.9%	9.4%	17.7%	4.5%	8.2%	11.3%

		Wind Forecast			Solar Forecast		
		2022	2026	2031	2022	2026	2031
Very Large Errors (±200 MW or more over 10 minutes, starting every 10 minutes during year)							
Reference Case	Average Size (MW)	278	298	316	N/A		
	Frequency (intervals/y)	301	467	642			
	Frequency (% of year)	0.6%	0.9%	1.2%			
Clean-Tech Scenario	Average Size (MW)	280	303	313	N/A		
	Frequency (intervals/y)	321	510	605			
	Frequency (% of year)	0.6%	1.0%	1.2%			
Renewables and Storage Rush Scenario	Average Size (MW)	285	305	363	235	243	258
	Frequency (intervals/y)	401	544	1,310	20	147	302
	Frequency (% of year)	0.8%	1.0%	2.5%	0.0%	0.3%	0.6%

For wind generation constant-ramp forecast errors in the Reference Case and Clean-Tech Scenario, the average size of large errors (of at least ±50 MW) increased by about 13 and 12 per cent, respectively, over the forecast period. Over the same time, the frequency of large errors increased by about 46 and 36 per cent, respectively.

As well, the average size of very large errors (of at least ±200 MW) increased by about 14 and 12 per cent, respectively, over the forecast period, and the frequency of those errors increased by about 113 and 88 per cent, respectively.

For wind generation constant ramp forecast errors in the Renewables and Storage Rush Scenario, the average size of large errors (of at least ±50 MW) increased by about 19 per cent over the forecast period. Over the same time, the frequency of large errors increased by about 123 per cent, respectively. As well, the average size of very large errors (of at least ±200 MW) increased by about 27 per cent over the forecast period, and the frequency of those errors increased by about 227 per cent.

The increase in size and frequency of large forecast error over 10-minute intervals is attributed primarily to the increase in the capacity of wind and solar generating assets and will increase the challenges of responding to net demand changes through energy market dispatch. The forecast uncertainty results are based on the assumed forecasting methods, which do not capture potential improvements or alternative forecast methodologies.

CUMULATIVE ABSOLUTE RAMP OF DISPATCHABLE ASSETS

As discussed in Ramp Distribution, 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.

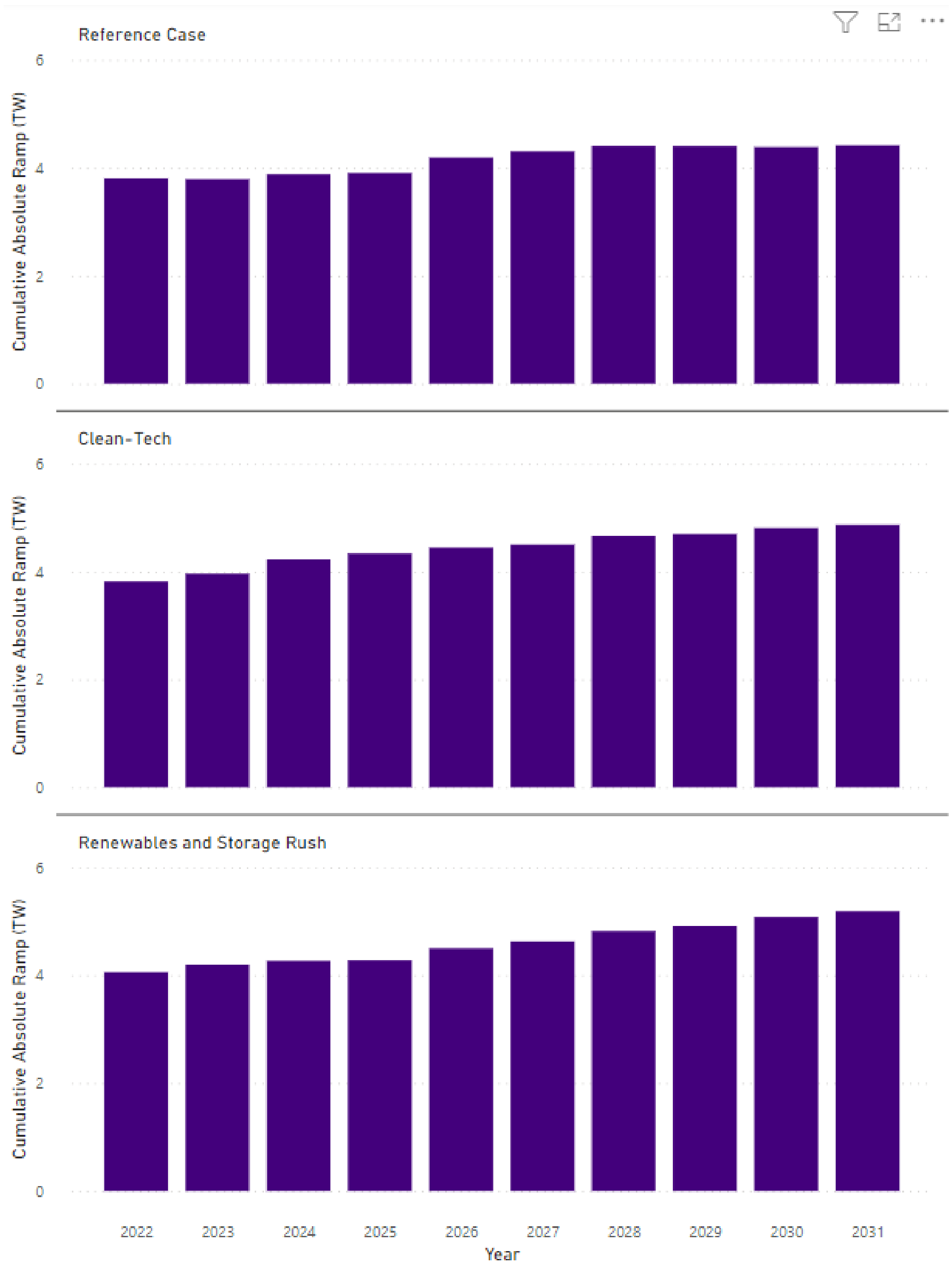
The combined effect of changes to ramp size and frequency may be assessed by examining cumulative absolute ramp of dispatchable assets, which provides the sum of all dispatchable generating asset ramps up and down on an absolute-value basis in aggregate. Each ramp up or down is measured in MW over an interval. The absolute value of each ramp up (positive) or down (negative) is then summed to calculate the cumulative absolute 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 ramp. Cumulative absolute ramp of dispatchable assets differs from the net demand variability (Ramp Distribution) in that the cumulative absolute ramp includes the effects of dispatches for ramping. Dispatches for ramping appear as an ordinary dispatch, but with the intention of contributing to the ramping needs of the system. In other words, a dispatch for ramping is utilized when the marginal assets have an insufficient ramp rate to match the system ramping needs. When the need for additional ramping subsides, any outstanding dispatches for ramping are reversed. Therefore, dispatches for ramping result in additional ramping of assets, which is measured using cumulative absolute ramp.

Figure 31 illustrates the cumulative absolute ramp of dispatchable assets in aggregate over all 10-minute intervals in each year of the forecast period, in the Reference Case, Clean-Tech Scenario, and Renewables and Storage Rush Scenario. Compared to 2022, cumulative absolute ramp of dispatchable generation increases over the forecast period by about 16 per cent in the Reference Case, by about 27 per cent in the Clean-Tech Scenario, and by about 28 per cent in the Renewables and Storage Rush Scenario.

Cumulative absolute ramp of dispatchable generation generally increases in proportion to increases in the variable generation capacity in the scenario. Cumulative absolute 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 compared to if a slow-ramping asset had responded.

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

Figure 31: Cumulative absolute ramp of dispatchable assets over 10-minute intervals by scenario



SYSTEM FLEXIBILITY RESPONSES TO NET DEMAND CHANGE

As discussed in section 5 (sub-section 5.1.3) 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.

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 32 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, Clean-Tech Scenario, and Renewables and Storage Rush Scenario.

Over the forecast period in all 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, by about 28 per cent in the Clean-Tech Scenario, and by about 24 per cent in the Renewables and Storage Rush Scenario. As well, the proportion of the response to system flexibility provided by each approach changes over the forecast period, as summarized in Table 11.

Figure 32: System flexibility responses to net demand change, measured as cumulative absolute change in response over 10-minute intervals, by scenario

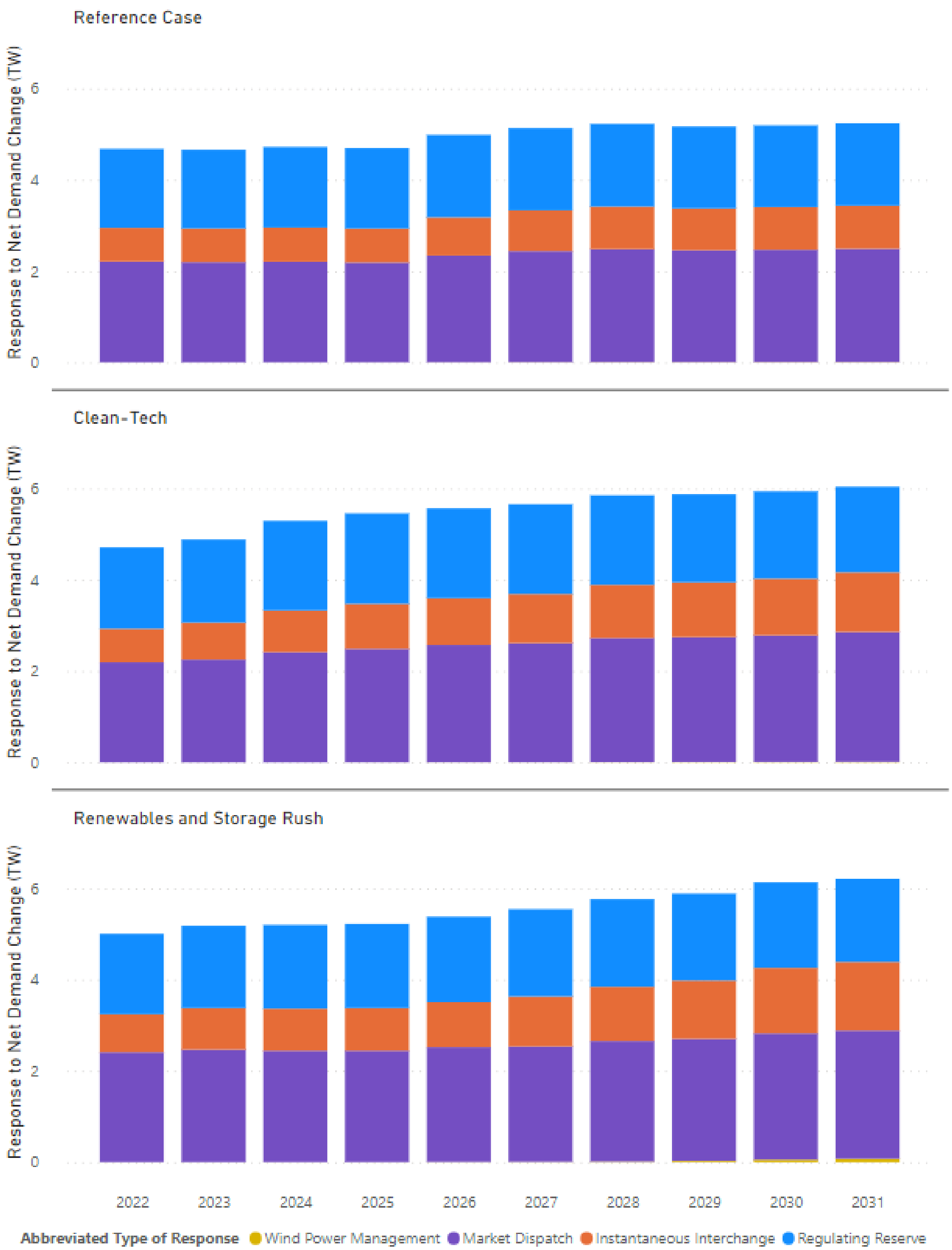


Table 11: Proportion of system flexibility responses to net demand by scenario

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%
Renewables and Storage Rush Scenario				
2022	48%	35%	0.0%	17%
2031	45%	29%	1.2%	24%

Note: Numbers may not add due to rounding

INDICATIVE MARKET IMPACT OF RESPONDING TO NET DEMAND VARIABILITY

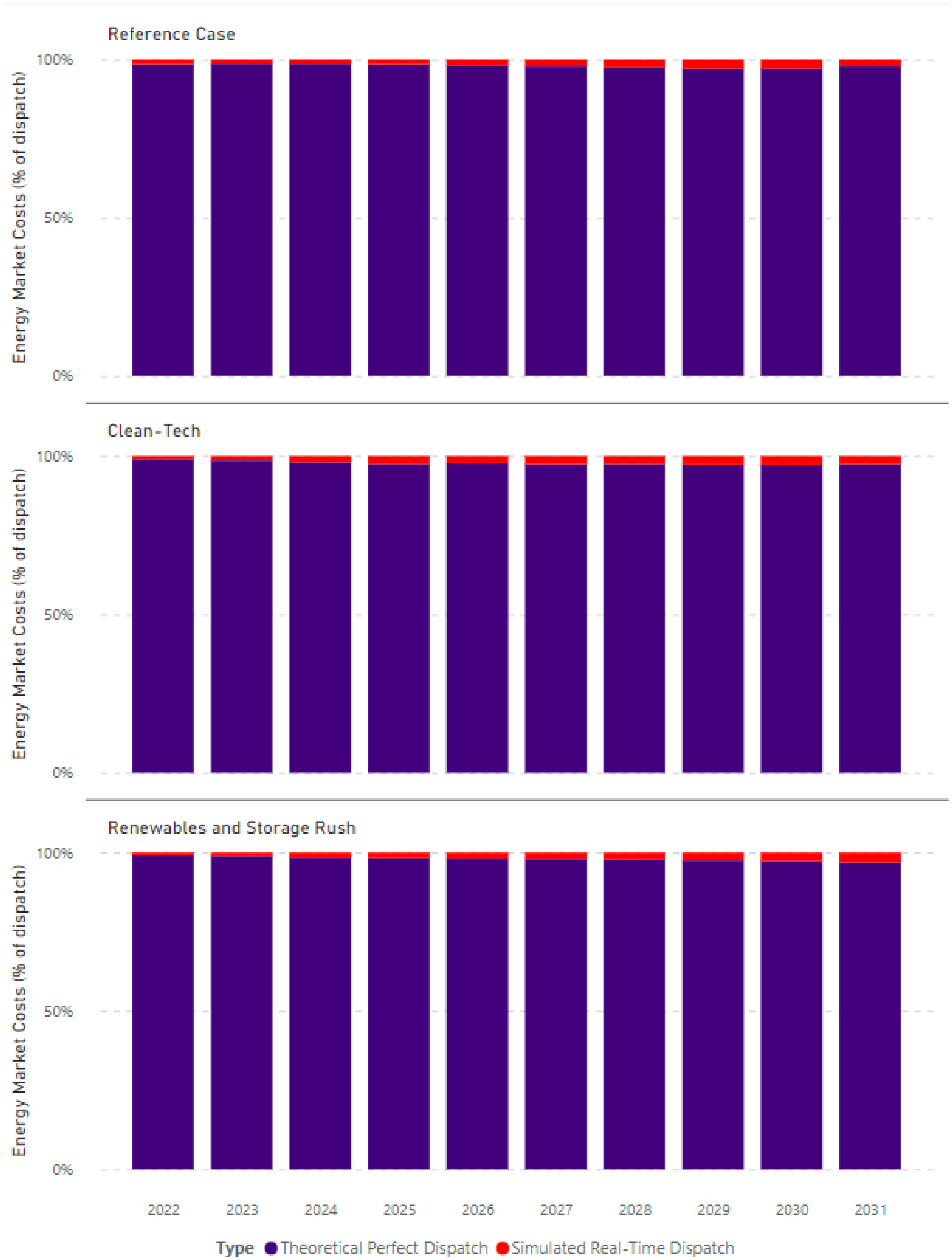
As discussed in section 5.1, system flexibility refers to the ability of the electric system to adapt to dynamic and changing conditions, particularly those related to net demand. If changes in net demand could be predicted with certainty over an interval, energy market dispatch could be used to precisely 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 theoretically 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 upcoming 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.

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, Clean-Tech Scenario, and Renewables and Storage Rush Scenario. Energy market costs with theoretical perfect dispatch are 0.9 per cent to 3.1 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 about 2.0 per cent lower in the Reference Case, about 2.2 per cent lower in the Clean-Tech Scenario, and about 1.9 per cent lower in the Renewables and Storage Rush Scenario, than with simulated real-time dispatch.

Figure 33: Indicative market impact of responding to net demand change by scenario



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 Appendix F. The AESO expects to continue examining the market impact of responding to net demand variability in future system flexibility assessments.

SIMULATED AREA CONTROL ERROR

As discussed in section 5.1.3 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 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 34 illustrates the duration and size of simulated area control error in 2022, 2026, and 2031 for the Reference Case, Clean-Tech Scenario, and Renewables and Storage Rush Scenario displayed using a hex-bin plot. 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). Each pair of duration and average difference is referred to as an area control error event, where the colour of each hexagon in Figure 34 displays the number of area control error events within its boundary.

Figure 34: Duration and size of simulated area control errors by scenario

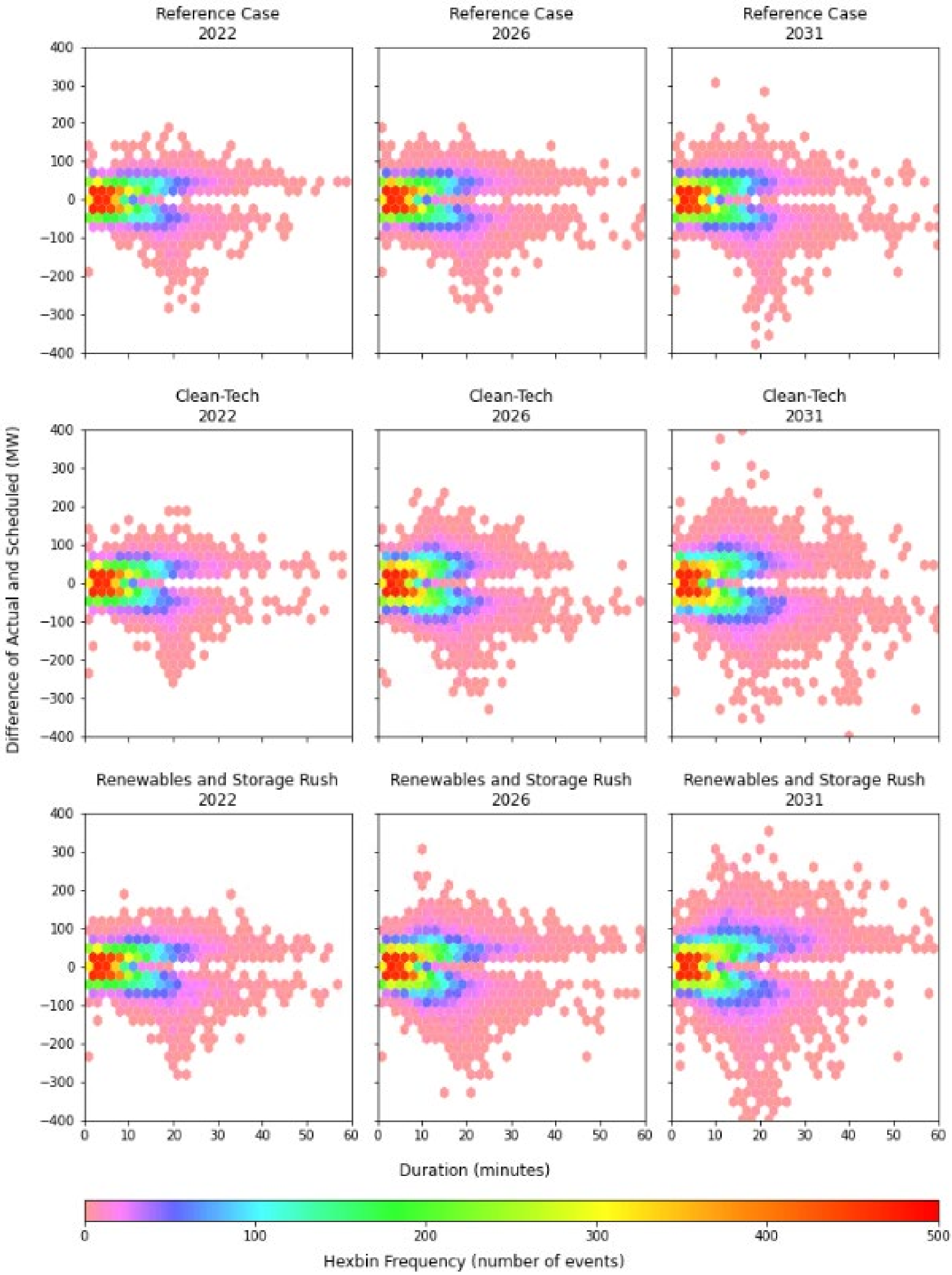


Table 12: Average size and duration of large ACE events by scenario

		Positive ACE Events			Negative ACE Events		
		2022	2026	2031	2022	2026	2031
Large ACE Events (average absolute size of 50 MW or more)							
Reference Case	Average Size (MW)	65	66	69	-74	-78	-82
	Average Duration (minutes)	13.4	12.4	12.9	14.8	14.9	15.2
	Total Duration (minutes/y)	13,371	14,600	17,261	13,942	19,699	23,794
	Total Duration (% of year)	2.5%	2.8%	3.3%	2.7%	3.7%	4.5%
Clean-Tech Scenario	Average Size (MW)	66	71	75	-75	-77	-82
	Average Duration (minutes)	12.8	11.3	11.6	14.3	13.5	14.3
	Total Duration (minutes/y)	11,713	21,303	31,824	13,341	29,193	43,726
	Total Duration (% of year)	2.2%	4.1%	6.1%	2.5%	5.6%	8.3%
Renewables and Storage Rush Scenario	Average Size (MW)	67	72	83	-78	-81	-95
	Average Duration (minutes)	13.3	13.5	15.6	15.4	13.2	14.5
	Total Duration (minutes/y)	14,800	26,336	50,981	19,548	24,336	39,818
	Total Duration (% of year)	2.8%	5.0%	9.7%	3.7%	4.6%	7.6%

		Positive ACE Events			Negative ACE Events		
		2022	2026	2031	2022	2026	2031
Very Large ACE Events (average absolute size of 200 MW or more)							
Reference Case	Average Size (MW)	-	-	263	-234	-238	-252
	Average Duration (minutes)	-	-	15.7	21.8	21.8	21.2
	Total Duration (minutes/y)	0	0	47	218	435	1,124
	Total Duration (% of year)	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%
Clean-Tech Scenario	Average Size (MW)	-	218	264	-219	-239	-266
	Average Duration (minutes)	-	13.0	13.7	18.7	19.0	25.3
	Total Duration (minutes/y)	0	65	302	243	608	1,872
	Total Duration (% of year)	0.0%	0.0%	0.1%	0.0%	0.1%	0.4%
Renewables and Storage Rush Scenario	Average Size (MW)	-	230	242	-235	-241	-294
	Average Duration (minutes)	-	11.3	18.6	20.9	20.3	20.5
	Total Duration (minutes/y)	0	79	875	417	669	3,075
	Total Duration (% of year)	0.0%	0.0%	0.2%	0.1%	0.1%	0.6%

Table 12 summarizes the average size and average duration of simulated area control error events in all scenarios. Table 12 illustrates that the average size of simulated area control errors increases in later years compared to earlier years of the forecast period in the Reference Case, Clean-Tech Scenario, and Renewables and Storage Rush Scenario, while the average duration remains consistent across the forecast period. While the duration of each event is remaining consistent, the total duration of large simulated area control error events per year is forecasted to increase by 29 per cent in the Reference Case, 172 per cent in the Clean-Tech scenario, and 244 per cent in the Renewables and Storage Rush Scenario over the forecast period. The total duration of very large simulated area control error events is forecasted to drastically increase over the forecast period by 437 per cent in the Reference Case, 795 per cent in the Clean-Tech Scenario, and 847 per cent in the Renewables and Storage Rush Scenario.

The greater number of simulated area control error events is attributed to the increasing solar generation capacity included in the simulations in later years, in the Clean-Tech Scenario, and in the Renewables and Storage Rush Scenario. 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 the solar generation forecast is modelled as constant cloud coverage in the dispatch simulation, solar variability is not captured in the forecast and is likely to result in instantaneous interchange over a 10-minute dispatch interval.

The increase in total duration of large and very large simulated area control events 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.

1.4 Planned High-Level Actions

The planned high-level actions to address system flexibility challenges are summarized as follows:

- Investigate opportunities to improve short-term wind and solar forecasting accuracy
- Improve short-term dispatch modelling sophistication to better reflect operations in a changing electricity environment
- Investigate the increased use of regulating reserves to manage increasing net-demand variability over the next two to five years
- Investigate additional potential mitigations to prepare for possible implementation from the mid-2020s on.

METRICS

Flexibility assessments have focused on metrics for asset commitment and supply and demand imbalance, such as supply cushion and area control error. Area control error provides insight into the system's flexibility capability as the ramping, dispatch, and supply and demand imbalance concerns flow through to impact area control error. However, this approach doesn't provide metrics that detail the degree to which each reliability concern is affecting area control error. Therefore, the following set of roadmap actions define metrics and requirements to better measure the impact of each reliability concern on system flexibility:

- **Asset commitment |** This assessment currently provides supply cushion, supply surplus, and asset cycling metrics. While these metrics provide insight into how dispatchable generating assets are impacted by additions of variable generation capacity, they do not differentiate between long-term adequacy and resource mix versus short-term asset commitment. The AESO is planning to define metrics which can directly capture the impact of short-term asset commitment decisions to help quantify the concern and how possible mitigations could help.

- **Ramping capability |** This assessment currently provides ramping capability metrics defined by the ramp rate and response delay measured across all installed capacity. While this provides insight as to how the ramping capability of the system is expected to change, these metrics do not provide a granular measurement of the ramping capability at different times within the dispatch simulations. For example, simulated conditions can impact the ramping capability, such as the location of the marginal asset in the energy market merit order, which other assets are situated near the marginal asset, or what the ramping requirement is at that point in time. The AESO is planning to define a more granular metric to measure the margin between the ramping capability and ramping requirement at different times within the dispatch simulations.
- **Supply and demand imbalance |** This assessment currently uses area control error events to quantify how supply and demand imbalances are changing across the forecast period. While these metrics capture the changes in size, duration, and frequency of area control error events, they do not capture the variability of area control error or differentiate between the underlying drivers impacting the area control error. The AESO is planning to define metrics that can more holistically measure the impacts to area control error based on the underlying drivers, such as forecast error, dispatch decisions, and asset responses to dispatches.

MODELLING UPDATES

As the technologies within the supply and demand mix are expected to introduce significant changes within the forecast period, the AESO's modelling of supply and demand must be able to adequately represent this changing environment. Therefore, the following set of roadmap actions identifies modelling changes required to simulate flexibility requirements into the future, improve the model's sustainability, and measure the to-be-defined metrics:

- **AIL |** Currently, AIL is modelled by hour and minute using historical load profile data from a selected weather year, and scaling the historical profiles by year to reflect forecast load levels. For the Renewables and Storage Rush Scenario, additional EV load was modelled by hour with adjustments for the season (winter and summer) and day type (weekday and weekend). The AESO is planning on improving the load model by differentiating the load components within the historical data and simulation. Additionally, the AESO is planning on weather-synchronizing the load components with the weather year.
- **Solar generation |** Solar generation is currently modelled using solar generation daily profile data available for 2020 and 2021, matching those daily profiles to historical solar daily profiles available for the selected weather year to synchronize weather conditions, and scaling the weather-matched daily profiles by year to reflect forecast solar generation capacity and expected geographic diversity. The AESO is planning on improving the solar generation profiles by building generation profiles for individual facilities based on weather data for the weather year, their physical location, and their simplified asset characteristics.
- **Wind generation |** Wind generation is currently modelled for a set of locations within Alberta using potential generation profiles based on the weather observed in a selected weather year. A subset of the generation profiles was aggregated together to represent the forecast wind capacity with geographic diversification. These profiles were purchased from a forecasting provider. As the AESO develops a methodology for building solar generation profiles, the AESO is also planning on building wind generation profiles for individual facilities based on weather data for the weather year, their physical location, and their simplified asset characteristics.
- **Energy storage |** Energy storage is currently modelled with charge and discharge profiles based on prices in the energy market simulation, with the same hourly profiles used in the dispatch

simulation. While this approach captures the effects of energy arbitrage at an hourly level, energy storage facilities are not modelled in the merit order and, therefore, are not providing intra-hour ramping capability within the dispatch simulations. The AESO will consider ways to improve energy storage modelling to capture impacts on system flexibility.

- **Dispatch decisions |** Currently, System Controllers dispatch the energy market on an ad hoc basis, where their dispatch decisions are based on forecasts, tools, and operational experience. The dispatch simulation utilizes a simplified representation of the System Controller to mimic their dispatching practice in a proactive manner. The AESO is planning on refining the dispatch model based on historical observations to better capture the current practices. Then, alternative dispatch models can be used to evaluate the impacts of different dispatching practices or tools.
- **Regulating reserve |** The dispatch model currently represents regulating reserve using a simplified approach. The AESO is planning on updating the regulating reserve model to better reflect how regulating reserve currently performs. This will allow the AESO to evaluate potential changes to regulating reserve and how changes impact area control error.

FEEDBACK

The market and dispatch simulations currently do not have a feedback mechanism to validate modelling assumptions. While the results reasonably align with expectations drawn from historical data, a feedback mechanism would be helpful to refine the modelling assumptions. The AESO is planning to analyze historical data, including the to-be-defined metrics, against the simulation results to improve assumptions and models, including asset bidding behaviour, forecast quality, and dispatch decisions.

INVESTIGATE POTENTIAL MITIGATIONS

The trends identified in section 5.3 collectively indicate that requirements for system flexibility will materially increase to maintain system reliability in response to increasing net demand variability and increasing variable generation capacity. The AESO expects 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. Instantaneous interchange with adjacent balancing authorities will increasingly be used for any remaining supply-demand imbalances that are not addressed through ramping capability and regulating reserve. Maintaining area control error within acceptable performance ranges will become more difficult over the forecast period.

The AESO plans to utilize regulating reserves to manage the increasing system flexibility needs over the next two to five years, which could include modifying and/or dynamically calculating the required regulating reserve volumes.

Through the market evolution initiative, the AESO will be evaluating potential changes to the market design. Herein, the AESO intends to evaluate potential market-based solutions for system flexibility, including the examples in section 5.4, building on the findings of this roadmap. Additionally, the AESO plans to evaluate the potential non-market-based mitigations with the intent to select market and/or non-market mitigations for possible implementation within the next five years. The need for system flexibility enhancements is being triggered by the increasing penetration of variable generation, larger variable generation facilities and the associated increase in volatility. 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.

OPERATIONAL PREPAREDNESS

The following set of roadmap actions identifies operational preparedness required to manage a more variable system:

- **Supply surplus |** Due to the supply surplus observation provided in Appendix C, section 1.3, the AESO is planning on reviewing the following to improve certainty when dispatching during supply surplus:
  - Section 202.5 of the ISO rules, *Supply Surplus*[47]
  - *Consolidated Authoritative Document Glossary*[48] for the definition of allowable dispatch variance
- **Tools |** As the penetration of intermittent renewables grows, the AESO is planning on improving forecasts and tools to provide the System Controllers with the information they need to make proactive and confident dispatch decisions
- **Power Ramp Management (PRM) |** PRM is an important tool that helps to limit the ramp-up rate from wind and solar assets
  - While section 5.4 identifies changes to wind and solar power ramp management as a potential mitigation to limit ramp-down events, the AESO will also investigate potential improvements to the PRM methodology to provide more certainty during the ramp-up of wind and solar

[47] Available at https://www.aeso.ca/rules-standards-and-tariff/iso-rules/complete-set-of-iso-rules/

[48] Available at https://www.aeso.ca/rules-standards-and-tariff/consolidated-authoritative-document-glossary/