AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Draft Power System Frequency Risk Review

June 2022

Consultation draft

A report for the National Electricity Market

Important notice

Purpose

This is a draft of the 2022 Power System Frequency Risk Review Report that AEMO will publish under clause 5.20A.3 of the National Electricity Rules (version 176). This draft report is published for consultation purposes only.

This publication has been prepared by AEMO using information available to 29/03/2022. Information made available after this date may have been included in this publication where practical.

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Version control

Version	Release date	Changes
XX	D/M/YYYY	Initial version

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Executive summary

AEMO undertakes the power system frequency risk review (PSFRR) for the National Electricity Market (NEM) in consultation with transmission network service providers (TNSPs) at least every two years, and publishes a PSFRR report under the National Electricity Rules (NER). This 2022 review will be the final PSFRR, which will be replaced from 2023 with an annual general power system risk review (GPSRR).

The purpose of the PSFRR is to review non-credible contingency events that have the potential to involve uncontrolled increases or decreases in frequency (alone or in combination) leading to cascading outages, or major supply disruptions. Where AEMO identifies a need for additional or alternative measures to manage the risk of such events over a five-year outlook period, the PSFRR assesses options considered technically and economically feasible and makes appropriate recommendations. This PSFRR includes updates on key findings and recommendations from the 2020 PFSRR[1].

The NEM is supporting a once-in-a-century transformation in the way society considers and consumes energy. Associated with this transformation, a range of factors influence the resilience of the NEM, in particular:

- Increased power transfer capability through major transmission corridors – while providing efficiency benefits through greater sharing of generation resources between regions, higher power transfers will increase the size of contingency events and the associated supply-demand imbalance if they occur.
- Operation with fewer synchronous generators – services previously provided as a by-product of energy production (such as inertia, frequency control ancillary services (FCAS) raise and system strength support) are becoming more scarce.
- The number and complexity of special protection schemes (SPSs) – including the potential for cascading operation of schemes.
- Increased connection of inverter-based resources (IBR) – poses additional challenges in maintaining grid stability, voltage and frequency control. Operating the grid reliably with IBR-dominated resources and managing volatility in variable renewable energy (VRE) output adds further challenges to dispatch planning.
- Increasing prevalence of distributed energy resources (DER) – impacting the efficacy of existing emergency frequency control schemes (EFCS), which were designed to disconnect load, but are now disconnecting load and generation (and in some cases, a net source of generation, exacerbating frequency disturbances). DER performance is increasingly a critical consideration for power system operations and security management.
- Concentrated provision of contingency FCAS in some regions.
- Evolving weather-related risks.

The PSFRR is a central body of work that explores the risks and consequences of non-credible contingency events and considers how these risks evolve over a five year planning horizon taking into account potential changes in power system operation over that period. The PSFRR builds on and complements other work

[1] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/power-system-frequency-risk-review.

undertaken by AEMO, such as the Integrated System Plan (ISP), Engineering Framework, and AEMO risk management initiatives.

Through consultation with TNSPs, review of previously identified risks and recent power system incidents, AEMO identified 10 priority non-credible contingency events for consideration in the 2022 PSFRR:

1. Separation of South Australia through loss of Heywood – South East 275 kilovolts (kV) lines considering potential operation with fewer than two synchronous generators prior to delivery of Project EnergyConnect (PEC) stage 2[2].
2. Separation of South Australia through loss of Moorabool – Mortlake (MLTS-MOPS) and Moorabool – Haunted Gully (MLTS-HGTS) 500 kV lines considering projected South Australian generation dispatch.
3. Separation of Queensland through loss of Queensland – New South Wales Interconnector (QNI) considering the increased flows following the QNI upgrade.
4. Loss of both 275 kV lines between Calvale and Halys with upgraded Central Queensland (CQ) and South Queensland (SQ) SPS.
5. Loss of the Victoria – New South Wales Interconnector (VNI).
6. Fault of the Mount (Mt) Lock 275 kV busbar in South Australia.
7. Loss of both Dederang to South Morang (DDTS-SMTS) 330 kV lines with updated Interconnector Emergency Control Scheme (IECS).
8. Loss of Columboola – Western Downs 275 kV lines resulting in large loss of load.
9. Simultaneous loss of multiple Loy Yang A generating units.
10. Loss of Ballarat – Waubra 220 kV line followed by Balranald – Darlington point 220 kV (x5) line or Darlington Point – Wagga 330 kV (63) line within 30 minutes.

Contingency studies were carried out in two parts. In the first part, contingencies 1 to 10 were studied against historical power system operating conditions relevant to the contingency. In the second part, contingencies 1 to 5 were studied against 2027 future scenarios. The 2027 future scenarios used forecast data from the 2022 Draft ISP *Step Change* scenario to set up study cases relevant to each contingency.

Contingencies 6 to 10 were excluded from future scenario studies as no material issues were identified and none were anticipated based on upon expected future conditions.

Separate recommendations are made in this report based on the historical and 2027 future study results respectively.

Summary of 2022 PSFRR recommendations

Based on historical studies

1. Queensland separation: Studies show that, when Queensland is exporting, frequency in Queensland could rise above 52 Hz following the loss of QNI. To regulate Queensland frequency so as to meet the Frequency Operating Standard (FOS), AEMO plans to collaborate with Powerlink to develop an over

[2] See https://www.projectenergyconnect.com.au/.

frequency generation shedding (OFGS) scheme for Queensland to manage over-frequency during separation.

2. Loss of both DDTS-SMTS 330 kV lines: To avoid multiple transmission line loss following this non-credible event, the following improvements are recommended:

   a) When Victoria is importing: The IECS scheme is used to manage the impact of the non-credible loss of both DDTS-SMTS 330 kV lines. The scheme is currently enabled only during bushfires in the vicinity of these lines and when Victoria is importing power from New South Wales. Considering the impact of this non-credible contingency event on the power system, it is recommended that AEMO (as Victorian transmission planner) review the arming criteria.

   b) When Victoria is exporting: It is recommended that AEMO (as Victorian transmission planner) modify or implement a new SPS similar to the present IECS to manage the non-credible loss of both DDTS-SMTS 330 kV lines when Victoria is exporting. It is recommended that AEMO (as Victorian transmission planner) work with Transgrid to evaluate the benefit of augmenting this scheme to mitigate the impact of this non-credible event.

3. Loss of both Columboola – Western Downs 275 kV lines: Studies indicate that this non-credible event could cause multiple transmission line losses, equipment overloading, and voltage collapse in the network around Surat in Queensland. Studies also indicate that this contingency could cause QNI to lose stability. To manage this contingency, it is recommended that Powerlink implement a new SPS under National Electricity Rules (NER) S5.1.8.

Based on 2027 future studies

Recommendations (3) to (7) are based on the 2027 future study findings, which applied the 2022 Draft ISP *Step Change* scenario forecasts. These recommendations are intended to prepare for the impacts of expected power system changes on power system security over a five year planning horizon.

4. Management of Queensland UFLS and QNI instability:

   a) Studies showed that following separation, Queensland frequency could collapse when QNI is importing, primarily due to insufficient UFLS during periods of high distributed photovoltaics (DPV) generation. AEMO has advised Powerlink and Energy Queensland to identify and implement measures to restore UFLS load, and to collaborate with AEMO on the design and implementation of remediation measures.

   b) Studies also show that QNI could lose stability following the loss of Heywood Interconnector (HIC), causing synchronous separation of both SA and Queensland, with potential for subsequent power system events to occur[3]. To manage QNI separation for HIC contingencies AEMO plans to conduct further investigation to consider appropriate mitigation measures such as a protected event or work with Powerlink for a SPS under NERS5.1.8.

5. Review the WAMPAC scheme to mitigate risks associated with non-credible loss of Calvale – Halys 275 kV lines: Following the QNI Minor upgrade, higher Queensland imports above 600 megawatts (MW) are possible. The studies indicate that, when Queensland imports above 600 MW coincide with high Central Queensland-Southern Queensland (CQ-SQ) transfers, the Wide Area Monitoring Protection and Control (WAMPAC) scheme will not be able to ensure QNI and CQ-SQ cut-set line stabilities. To manage the non-

[3] By inference, as observed during actual power system events.

credible loss of Calvale – Halys 275 kV lines, it is recommended that Powerlink modify WAMPAC to ensure it can effectively manage this contingency.

6. Further work is required to mitigate risks associated with reduced effectiveness of UFLS schemes reported in the 2020 PSFRR:

    1. To address the impact of DPV growth on UFLS, AEMO recommends that network service providers (NSPs) regularly audit the availability of effective UFLS considering the impact of DPV in their respective networks. The results should be regularly provided to AEMO for inclusion in risk assessments, UFLS reviews and planning studies.

    2. AEMO has advised NSPs to immediately seek to identify and implement measures to restore emergency under-frequency response to as close as possible to the level of 60% of underlying load at all times. Where this is not feasible, AEMO will collaborate with NSPs to develop an approach that identifies a level of emergency under-frequency response that is achievable, while delivering a significant reduction in power system security risks.

    3. AEMO recommends that NSPs investigate measures to remediate the impacts of 'reverse' UFLS operation due to negative power flow on UFLS circuits, and investigate arrangements to measure UFLS load availability in real time to inform power system operation and planning studies.

7. Further work is required to assess the impacts of higher rates of change of frequency (RoCoF) as system inertia reduces: Studies conducted with projected inertia levels indicate that excessive OFGS and UFLS action can occur during high RoCoF events. AEMO will continue to monitor this in future general power system risk reviews and review OFGS/UFLS settings, if required.

Revision of existing protected event

8. Revise constraints on Heywood associated with the existing protected event for destructive wind conditions in SA:

    a) Until PEC Stage 1 is delivered (currently planned for the second half of 2023), AEMO considers it will be necessary to retain the 250 MW SA import limit on the Heywood interconnector during destructive wind conditions.

    b) As part of the delivery of PEC Stage 1, AEMO recommends the Wide Area Protection Scheme (WAPS) EFCS is modified to account for the change in network topology, and that the existing 250 MW HIC import limit is replaced by a 430 MW HIC import limit, and a 70 MW PEC Stage 1 import limit during destructive wind conditions. (Note PEC Stage 1's import limit under normal conditions is expected to be 100 MW)

    c) AEMO will consider whether the existing protected event could be managed under the new reclassification framework (from March 2023)[4] and, if so, determine the applicable reclassification criteria and recommend revocation of the protected event.

Other key recommendations

a) Due to the penetration of DPV and transmission-connected IBR, South Australia is becoming more susceptible to large generation ramping events. Through analysis, AEMO has identified ramping events in South Australia in 2021 where the combined DPV and IBR generator output reduced by

[4] National Electricity Amendment (Enhancing operational resilience in relation to indistinct events) Rule 2022 No. 1

over 1,750 MW over 2.5 hours. AEMO is analysing historical ramping events to understand ramping risks and how changes in synchronous generator dispatch requirements could impact AEMO's ability to manage future ramping events. After its review is complete, AEMO plans to explore options to forecast and manage future NEM ramping events.

b) Western Victoria Renewable Integration Regulatory Investment Test for Transmission (RIT-T) – is anticipated to be completed by the end of 2025. This network reinforcement will enable greater transfer of generation from western Victoria to Melbourne by building a new 220 kilovolts (kV) double circuit transmission line from Bulgana to a new terminal station north of Ballarat, and a new 500 kV double circuit from north of Ballarat to Sydenham[5]. The non-credible loss of the proposed 500 kV lines during period when the new 500 kV lines flow exceeds the limits of the parallel 220 kV lines, could result in multiple line losses. AEMO Vic planning is advised to consider this risk in the planning process.

General Power System Risk Review

In 2023 AEMO will undertake the first GPSRR, which replaces the PSFRR. The GPSRR will be completed annually and will have a broader scope to explore a wider range of risks that could have adverse impacts on the power system.

Industry consultation

AEMO is now seeking email submissions on this draft report from all persons interested in the PSFRR. In particular, we invite feedback regarding the methodology, findings and recommendations. Submissions will contribute to the finalisation of the 2022 PSFRR report.

If you would like to make a submission, please email it to psfrr2022@aemo.com.au. Written submissions will be accepted until 5.00 pm (AEST) 17 June 2022.

Submissions will be published on AEMO's website. Please indicate to AEMO if there are any parts of your submission you would like kept confidential, with reasons why.

[5] Section 3.3.2 of the 2021 Victorian Annual Planning Report.

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Figures

Abbreviations and key terms

Abbreviations

Abbreviation	Term
AC	alternating current
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AEST	Australian Eastern Standard Time
AGC	Automatic Generation Control
APD	Alcoa Portland
AUFLS	Automatic Under frequency Load Shedding Scheme
BESS	Battery Energy Storage System
CB	Circuit Breaker
CQ-SQ	Central QLD-South QLD
CT	Current Transformer
DC	direct current
DER	distributed energy resources (including distributed photovoltaics and embedded synchronous generators)
DDTS-MSS	Dederang – Murray
DDTS-SMTS	Dederang – South Morang
DNSP	Distribution Network Service Provider
DPV	Distributed Photovoltaic
DSA	Dynamic Security Assessment
EAPT	Emergency Alcoa-Portland Potline Tripping scheme
EFCS	Emergency Frequency Control Scheme
EFETL	Extreme Frequency Excursion Tolerance Limit
EMS	Energy Management System
EMT	electromagnetic transient
ESOO	Electricity Statement of Opportunities
EVM	Enhanced Voltage Management
FCAS	frequency control ancillary services
FFR	Fast Frequency Response
FOS	Frequency Operating Standard
FRM	Frequency Recovery Mode
FY	Financial year
GPSRR	General Power System Risk Review
HIC	Heywood Interconnector
HYTS	Heywood Terminal Station
Hz	Hertz
IBR	Inverter-based resources

Abbreviation	Term
ICCP	Inter-Control Centre Communications Protocol
IECS	Interconnector Emergency Control Scheme
ISP	Integrated System Plan
kV	Kilovolts
LOR	Lack of Reserve
MLTS	Moorabool Terminal Station
MLTS-MOPS	Moorabool – Mortlake
MLTS-HGTS	Moorabool – Haunted Gully
MVA	megavolt amperes
MVAr	megavolt-amperes reactive
MW	megawatts
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
NOFB	Normal Operating Frequency Band
NSP	network service provider
NSW	New South Wales
AS/NZS	Australian/New Zealand Standard
OFGS	over frequency generation shedding
OFTB	Operational Frequency Tolerance Band
OPDMS	Operations and Planning Data Management System
PEC	Project EnergyConnect
PFR	primary frequency response
POE	Probability of Exceedance
PSFRR	Power System Frequency Risk Review
PSSE	Power System Simulator for Engineering (also PSS®E or PSS/E)
PV	photovoltaic
QLD	Queensland
QNI	Queensland – New South Wales Interconnector
RERT	Reliability and Emergency Reserve Trader
ROCOF	rate of change of frequency
RTO	Real Time Operations
SA	South Australia
SAPN	SA Power Networks
SCADA	Supervisory Control and Data Acquisition
SESS	South East Switching Station
SF	Solar Farm
SIPS	System Integrity Protection Scheme
SPS	Special Protection Scheme
SVC	Static VAR Compensator
SW500SCS	South West 500 kV Special Control Schemes

Abbreviation	Term
TI	Trading Interval
TNSP	transmission network service provider
UFLS	under frequency load shedding
VIC	Victoria
VNI	Victoria – New South Wales Interconnector
VRE	variable renewable energy
WAMPAC	Wide Area Monitoring Protection and Control
WAPS	Wide Area Protection Scheme
WF	Wind Farm

Key report terms

Term	Explanation
Satisfactory operating state	The power system is defined as being in a satisfactory operating state when: • Power system frequency is within the normal operating frequency band • Voltage magnitudes are within relevant limits • Current flows on all transmission lines are within equipment ratings • All other plant forming part of the power system is being operated within its ratings • The power system is being operated such that fault potential is within circuit breaker capabilities • The power system is considered stable
Secure operating state	The power system is defined to be in a *secure operating state* when: • The power system is in a satisfactory operating state • The power system will return to a satisfactory operating state following any *credible contingency event.*
Credible contingency event, also referred to as credible contingencies	A *credible contingency event* means a contingency event the occurrence of which AEMO considers to be reasonably possible in the surrounding circumstances including the technical envelope. Without limitation, examples of credible contingency events are likely to include: • the unexpected automatic or manual disconnection of, or the unplanned reduction in capacity of, one operating generating unit; or • the unexpected disconnection of one major item of transmission plant (e.g. transmission line, transformer or reactive plant) other than as a result of a three phase electrical fault anywhere on the power system.
Non-credible contingency event, also referred to as non-credible contingencies	A *non-credible contingency event* is a contingency event other than a *credible contingency event*. Without limitation, examples of non-credible contingency events are likely to include: • three phase electrical faults on the power system; or • simultaneous disruptive events such as: – multiple generating unit failures; or – double circuit transmission line failure (such as may be caused by tower collapse).

1 Introduction

1.1 Purpose

AEMO has prepared this consultation draft of the 2022 power system frequency risk review (PSFRR) under rule 5.20A of version 176 of the National Electricity Rules (NER). This will be the final PSFRR, which will be replaced by the annual general power system risk review (GPSRR) from 2023[6]. Rules and clauses cited in this report refer to version 176 of the NER unless otherwise stated.

This report addresses AEMO's obligations under clause 5.20A of the NER. Under this clause, AEMO, in consultation with transmission network service providers (TNSPs), must undertake a PSFRR for the National Electricity Market (NEM) at least once every two years, considering:

- Non-credible contingency events which AEMO expects would likely involve uncontrolled frequency changes leading to cascading outages or major supply disruption.
- Current arrangements for managing such non-credible contingency events.
- Options for future management of such events.
- Likelihood of such events occurring.
- The performance of existing special protection schemes (SPSs), including emergency frequency control schemes (EFCSs) which impact system frequency performance.

The purpose of the PSFRR is to review the potential for non-credible power system contingency events to cause frequency changes large enough to initiate generator disconnections and result in widespread transmission outages or a black system. The PSFRR involves assessment of key non-credible contingency events based on a review of historic events and known risks, in consultation with TNSPs. It is not a comprehensive review of all non-credible contingency events which could occur on the power system.

The key outcome of this risk review is to identify non-credible contingency event management options to improve the resilience of the power system that AEMO assesses to be technically feasible, and economically feasible based on a preliminary cost-benefit assessment.

1.2 Risk management in the NEM

1.2.1 Power system security

Non credible contingency events, by definition, are not considered reasonably possible during normal power system operating conditions, and AEMO is not required to account for them in its real-time management of the power system.

Various safeguards exist within the power system to respond to non-credible contingency events should they occur and reduce their impact on power system frequency. Key safeguards are:

[6] See NER clause 11.138.2, NER version 177. Subject to the transitional rules, the GPSRR provisions were introduced in version 177 (10 January 2022) by the *National Electricity Amendment (Implementing a general power system risk review) Rule 2021*.

- Under frequency load shedding (UFLS) schemes – trip blocks of load to restore the supply demand balance.
- Special protection schemes for particular contingency events – can trip or runback generation, trip load or transmission equipment or initiate other actions to mitigate the impact of power system events.

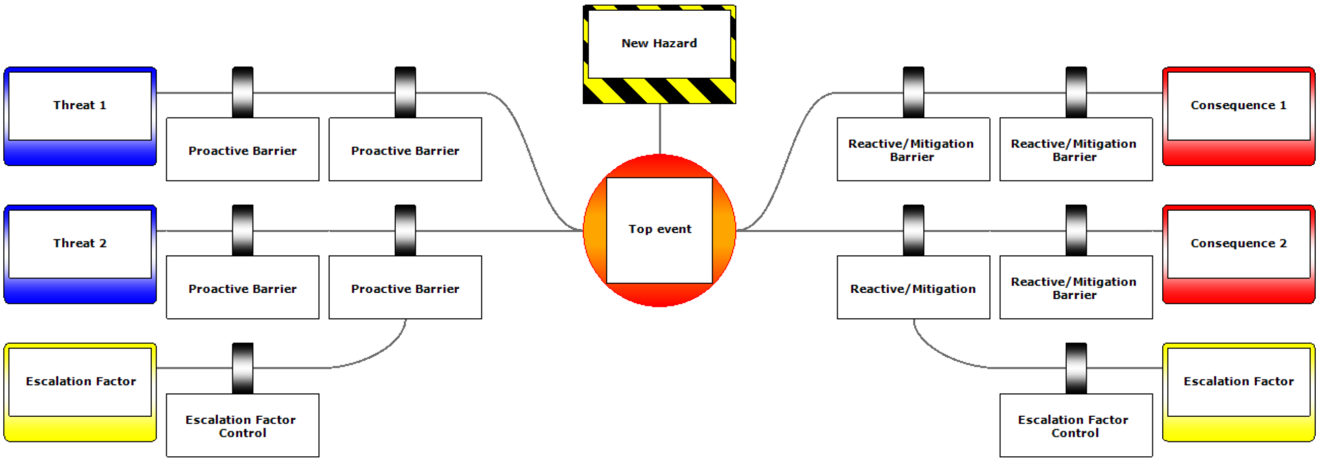
1.2.2 AEMO's risk management methodology

To effectively identify and manage risks associated with operating the power system, AEMO applies the principles of the AS/ISO 31000 risk management framework, undertakes root-cause analysis for major power system events, and has adopted the BowTie methodology, the benefits of which are that it:

- Provides a graphical representation of all aspects of risk.
- Is simple to understand and effective.
- Gives a logical, structured approach to risk management.
- Is increasingly seen as best practice, especially in high-risk industries.
- Allows interdependencies to be recognised and assessed (vertically and horizontally).

Figure 1 presents a diagram of the BowTie risk assessment method. In the centre of the BowTie is the hazard – hazards can be operations, activities or situations. A hazard has the potential to cause harm, but cannot do so as long as adequate controls are in place. When control of a hazard is lost, a normal situation changes to an abnormal situation. In the BowTie, this event/change is called the top event and appears in the centre of the diagram. For example, a top event could be a frequency excursion on the power system. To the far left of the top event are the threats, the things that could cause a top event to occur.

Figure 1 BowTie risk evaluation diagram



1.2.3 NER requirements related to the PSFRR

Rule 5.20A of the NER sets out the scope of the PSFRR and the matters to be assessed and reported on. AEMO's findings and recommendations on these matters, where actioned, intersect with several other NER requirements and responsibilities, particularly, but not exclusively, in relation to EFCS (primarily UFLS). Many of these rules apply independently of the PSFRR. Table 1 lists NER clauses relevant to the PSFRR

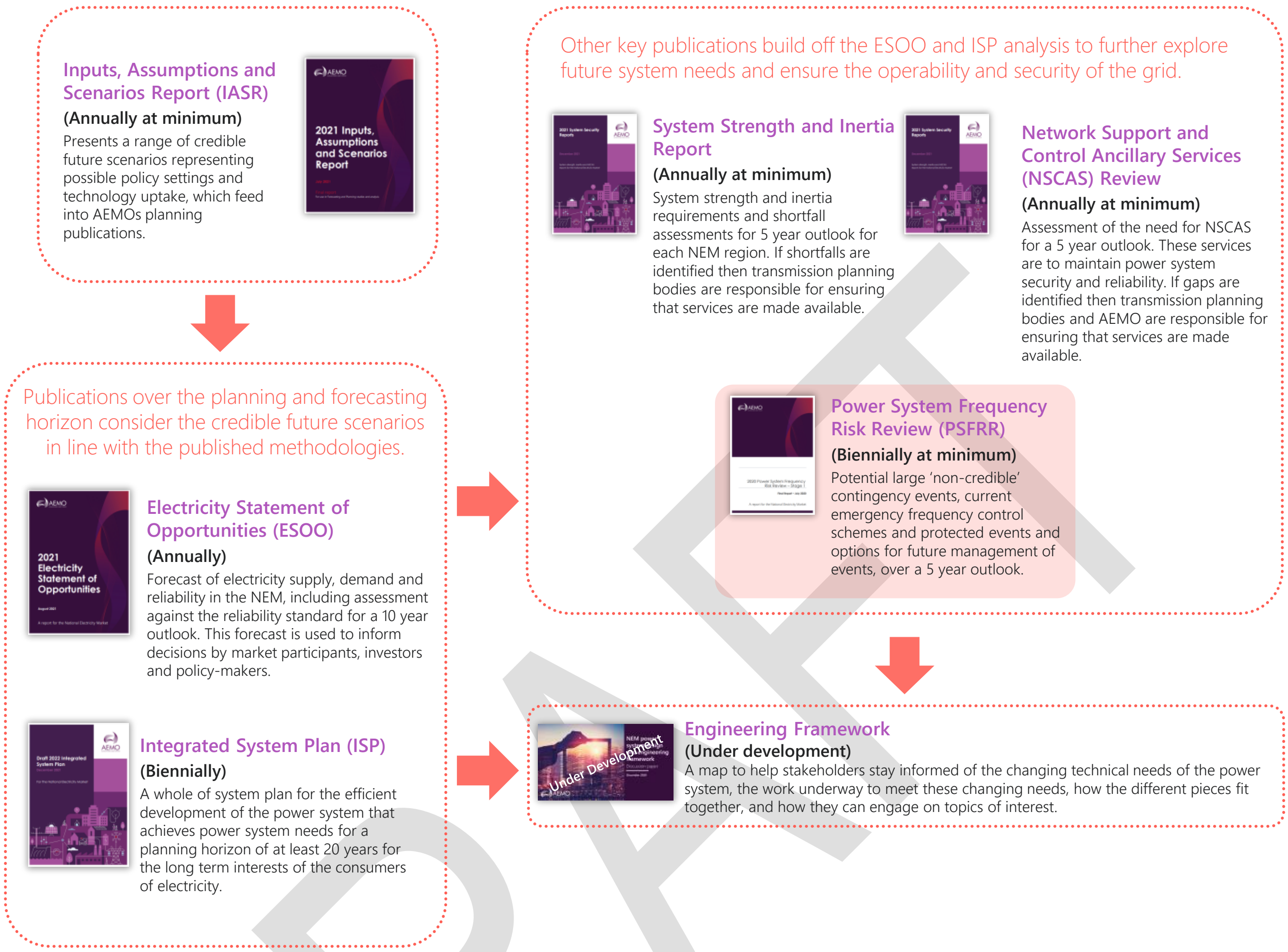
Table 1 NER requirements related to the PSFRR

NER Clause	Description
4.3.1(k), (p1)	System security – AEMO's responsibilities that relate to, or are impacted by, the responses of EFCS.
4.3.1(n), 4.3.2	System security – AEMO to provide information to facilitate resolution of risks outside AEMO's control; requirements for AEMO to develop EFCS settings schedules in consultation with network service providers (NSPs) and (as relevant), jurisdictional system security coordinators and generators.
4.3.4	NSP cooperation with AEMO to achieve power system security responsibilities, and specifically in relation to the design and implementation of EFCS and the provision of sufficient interruptible loads.
4.3.5, S5.3.10, S5.6 Part A (k)	Market Customer responsibilities for providing interruptible load from facilities with at least 10 megawatts (MW) peak demand.
5.14, 5.16, 5.17	Joint planning obligations where recommended investments involve more than one NSP, and the application of the regulatory investment test to investments other than protected event EFCS.
S5.1.8	NSP planning obligation to consider non-credible contingency events – such as busbar faults which result in tripping of several circuits, uncleared faults, double circuit faults and multiple contingencies – which could potentially endanger the stability of the power system.
S5.1.10.1(a)	NSPs, in consultation with AEMO, to ensure that UFLS loads are sufficient to minimise or reduce the risk that frequency will exceed the extreme tolerance limits in the event of multiple contingency events.
S5.1.10.1a	NSP obligations to: • provide AEMO with information and assistance for development and review of EFCS settings schedules; • following the determination of a protected event EFCS standard, design, procure, commission, maintain, monitor, test, modify and report to AEMO on the EFCS so as to achieve the standard; • use reasonable endeavours to achieve commissioning of a new or upgraded EFCS within the time contemplated by a PSFRR or Reliability Panel declaration as applicable; • for an over frequency generation shedding (OFGS) scheme, notify and negotiate with relevant generators for inclusion in the scheme.
S5.1.10.2	Distribution network service provider (DNSP) obligations to cooperate with TNSPs, provide and maintain UFLS facilities and apply settings as required.
5.7.4, S5.1.10.3, S5.1.10.2(b)	NSP responsibilities for UFLS compliance and testing

1.2.4 PSFRR relationship with other reports

The PSFRR draws inputs from, and informs and underpins, a number of related reports and processes owned by AEMO and TNSPs. Figure 2 below shows the PSFRR in relation to other key AEMO documents and processes.

Figure 2 Relationship of PSFRR with other AEMO documents and processes



PSFRR relationship with the Engineering Framework

AEMO's Engineering Framework[7] is a toolkit to define the full range of operational, technical and engineering requirements needed to deliver the futures envisaged by the Integrated System Plan (ISP). Through open and transparent collaboration with stakeholders, the framework seeks to facilitate an orderly transition to a secure and efficient future power system. In July 2021, as part of the framework (and through collaboration with industry) AEMO released an Operational Conditions Summary[8] highlighting the likely generations mix and loading combinations five to 10 years in the future that necessitate changes to current operational practices.

In addition, potential gaps related to the Operational Conditions[9] have been identified by AEMO (with input from industry stakeholders), which represent the potential steps to securely and efficiently 'bridge the gap' between today and future operating conditions that, if not actioned, could inhibit or constrain the energy transition.

The PSFRR aligns with the Engineering Framework by:

[7] See https://aemo.com.au/en/initiatives/major-programs/engineering-framework#:~:text=The%20Engineering%20Framework%20is%20a,and%20efficient%20future%20NEM%20system.

[8] See https://aemo.com.au/-/media/files/initiatives/engineering-framework/2021/nem-engineering-framework-july-2021-report.pdf?la=en&hash=04E2BEFE4A1A7281B6294B1C8228AD59.

[9] And as highlighted in the published Engineering Framework Initial Roadmap, at https://aemo.com.au/-/media/files/initiatives/engineering-framework/2021/nem-engineering-framework-initial-roadmap.pdf?la=en.

- Helping AEMO identify any emerging power system security gaps that relate specifically to frequency.
- Identifying existing and emerging power system risks and suggesting actions to manage those risks.

1.2.5 Evolution of the risk review

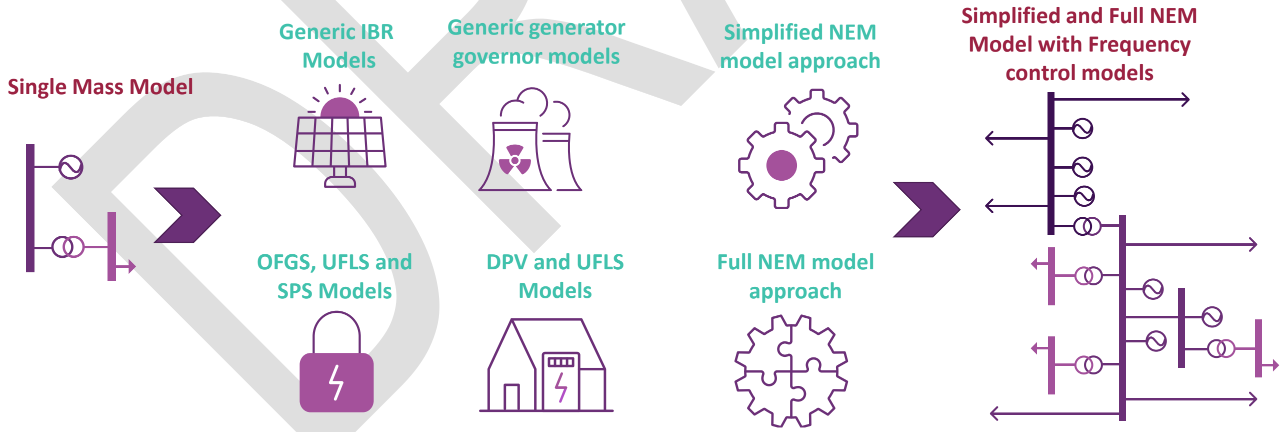
AEMO published the first PSFRR in 2017, in the wake of the 2016 South Australia black system event. This first review focused solely on mitigating the risk of non-credible loss of multiple generating units in South Australia when South Australia is importing energy from Victoria (the conditions that led to the 2016 black system event). It drew on the analysis and recommendations of AEMO's final report on the black system event[10]. AEMO published the first NEM-wide PSFRR report in 2018. Since the 2017 and 2018 PSFRRs, considerable effort has been put into increasing the accuracy of simulated frequency results by improving the modelling used for the study. In addition, AEMO has significantly increased the number of contingencies studied in the review to better understand and address more risks.

The key modelling improvements AEMO has made for more accurate frequency predictions include:

- Adopting generic governor models with PFR settings.
- Inclusion of generic inverter-based resources (IBR) models for legacy IBR plants that do not have models.
- Inclusion of over frequency generation shedding (OFGS) and UFLS models.
- Inclusion of DPV and distributed energy resources (DER) models.
- Addition of SPS models for key schemes, particularly those associated with major NEM interconnectors.
- Adopting simplified and full NEM network models for the studies.

The modelling improvements are figuratively represented in Figure 3.

Figure 3 PSFRR study model improvements in full OPDMS and in NEM simplified models since 2017



OPDMS: AEMO's Operational Data Management System

To validate the accuracy of the models used for the 2022 PSFRR studies, the model responses were benchmarked against several real power system event measurements The results of this benchmarking are included in Appendix A4.

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[10] AEMO, Black System South Australia 28 September 2016 – Final Report, March 2017, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Integrated-Final-Report-SA-Black-System-28-September-2016.pdf.

1.3 Key updates since the 2020 PSFRR

Modifications to existing emergency frequency control schemes

The status of the reviews and updates to emergency frequency control schemes (EFCS) are summarised below:

- UFLS: Work is underway with NSPs in South Australia, Victoria and Queensland to remediate UFLS performance in periods with high levels of DPV[11].
- OFGS: AEMO is currently reviewing the South Australia and Western Victoria OFGS schemes. Preliminary findings indicate that changes will be required to ensure these schemes remain adequate in the near future. AEMO is planning to complete its assessment in Q4 2022.
- Emergency Alcoa – Portland Potline Tripping (EAPT) scheme: AEMO (as Victorian transmission planner) has completed the review of EAPT scheme and updates to the existing scheme are expected to be completed by the end of FY 2022.
- Wide Area Protection Scheme (WAPS) in South Australia: WAPS is expected to be commissioned by early 2023.
- System Integrity Protection Scheme (SIPS) in South Australia: SIPS stage 1 and 2 are expected to be de-commissioned following the commissioning of WAPS. However, the SIPS Stage 3 Heywood Interconnector (HIC) phase swing transient stability relay will remain in operation.
- Wide Area Monitoring Protection and Control (WAMPAC): WAMPAC stage 1 is now in service, and this increases the reliability of the power system compared with the original SPS. According to Powerlink, due to expected lower utilisation levels of the Central to Southern Queensland intra-connector, Powerlink is not currently progressing WAMPAC stage 2, but prioritising other applications of WAMPAC that will provide positive benefits to customers as Powerlink rolls out a large program of reinvestment and maintenance activities in Central and North Queensland. Please see Appendix A2 for additional details.
- Interconnector Emergency Control Scheme (IECS): AEMO (as Victorian transmission planner) has completed a review of IECS and the outcomes are:
  - To offset the impacts of DPV on IECS action, it is proposed to add additional load blocks into the scheme.
  - The review identified no adverse interactions between IECS and UFLS.
  - The review concluded that the remaining risk of IECS operation being insufficient to prevent Victoria and New South Wales separation during low probability operating conditions is acceptable. This is aligned with the purpose of the IECS, which is to reduce the risk of separation.

DER compliance with AS/NZS4777.2:2020

Preliminary analysis indicates that only 30-50% of distributed inverters installed since January 2022 are being installed correctly under the new Australian Standard AS/NZS4777.2:2020, which became mandatory from 18 December 2021. This new standard requires important disturbance ride-through capabilities from distributed inverters. Low compliance means that contingency sizes associated with unintended disconnection of distributed inverters will continue to grow.

[11] AEMO, Adapting and managing under frequency load shedding at times of low demand, at https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/operations/adapting-and-managing-under-frequency-load-shedding-at-times-of-low-demand.

Preliminary evidence suggests that urgent work is required to significantly improve compliance rates over the next six months to reduce the risk of major market and power system security impacts. AEMO is working with the Clean Energy Council, distribution network service providers (DNSPs) and other industry participants to encourage rapid remediation.

Adequacy of under frequency load shedding schemes

Operationally AEMO is seeing increasing levels of generation from DPV are reducing the power flow on UFLS circuits. This reduces the effectiveness of UFLS. South Australia now has periods where the total UFLS load in the region is negative. Forward projections indicate that other regions are trending towards very low levels of UFLS availability (for more detail on UFLS projections please see Table 4 in section 3.3.2 of this report). AEMO has advised NSPs in South Australia, Queensland, Victoria and New South Wales to immediately seek to identify and implement measures to restore net UFLS load (or equivalent emergency under frequency response)[12]. In addition, a number of specific recommendations are included in this year's PSFRR report to mitigate the risks associated with reduced UFLS effectiveness.

Management of frequency in South Australia

The existing and proposed actions to manage South Australian frequency during non-credible contingencies are summarised below:

- Existing protected event: The protected event for loss of multiple transmission elements causing generation disconnection in South Australia during periods where destructive wind conditions are forecast by the Bureau of Meteorology is presently managed by the SIPS EFCS and limiting HIC flow. The 2022 PSFRR considers the adequacy of this protected event and recommends it continue until its next review. It recommends the measures to manage the protected event (HIC limiting and EFCS) continue, and are modified to remain effective as part of the delivery of Project EnergyConnect (PEC) Stage 1. It also notes the possibility for future management of the protected event under an expanded reclassification framework rather than the protected event framework.
- Remediation of UFLS in high PV periods: New loads have been added to the South Australia UFLS, and SA Power Networks (SAPN) is progressing implementation of dynamic arming of UFLS relays (blocking relays when the circuit is in reverse flows). Further work is underway to explore how to address the residual shortfall.
- New protected event for separation at Heywood Terminal Station (HYTS) and Moorabool Terminal Station (MLTS): AEMO is intending to make a submission to the Reliability Panel in Q3 2022 to propose a new protected event for separation of South Australia from the rest of the NEM. This will aim to formalise the existing constraints implemented under South Australian electricity regulations[13], as well as consider additional measures to manage a separation at Moorabool and manage frequency recovery post separation.
- Management of over-frequency: AEMO has reviewed the South Australia OFGS and suggested improvements to better manage the over frequency risks. As a first step, AEMO will be working with ElectraNet to implement the improvements.
- PEC-1 / PEC-2: ElectraNet is designing a new PEC SPS to enable maximum transfer on PEC and HIC, while minimising the risk of power system instability following non-credible contingencies. ElectraNet, Transgrid and

[12] AEMO, Adapting and managing under frequency load shedding at times of low demand, at https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/operations/adapting-and-managing-under-frequency-load-shedding-at-times-of-low-demand.

[13] *Electricity (General) Regulations 2012*, regulation 88A.

AEMO (as Victorian transmission planner) are reviewing relevant existing emergency control schemes to determine if changes are needed associated with this major project .

1.4 Acknowledgements

AEMO acknowledges support from the following participants, which enabled AEMO to complete the 2022 PSFRR:

- TNSPs for their support for inputs, identification of priority events for the studies, and review comments.
- Industry consultation forum participants for their comments and observations on PSFRR presentations.
- F&M Ringrose Pty Ltd for assistance with development of generic governor models.

1.5 Consultation process

In developing the 2022 PSFRR, AEMO has consulted and collaborated with the primary TNSPs in all regions (AEMO, Powerlink, Transgrid, ElectraNet and TasNetworks). AEMO has also worked with generators to improve model accuracy and engaged with the wider industry on specific issues. A summary of the major consultation actions AEMO has taken during the PSFRR is included below.

Completed:

- June 2021 – TNSP engagement to discuss their inputs to the PSFRR. Each TNSP was asked to complete a risk assessment of high impact non-credible contingency events within their network.
- August 2021 – AEMO wrote to primary frequency response (PFR) enabled generators requesting confirmation that AEMO holds accurate generator PSS®E models.
- September 2021 – AEMO provided the 2022 PSFRR approach paper to all TNSPs for review.
- December 2021 – AEMO held a 2022 PSFRR industry briefing with stakeholders across the NEM.
- February 2022 – AEMO presented PSFRR historical study results to all TNSPs for comment.
- April 2022 – AEMO presented PSFRR future study results to all TNSPs for comment.
- April 2022 – AEMO shared preliminary draft 2022 PSFRR report with TNSPs for review and comment.
- June 2022 – AEMO published this draft 2022 PSFRR report for industry consultation, to be supported by an industry briefing.

Planned:

- June 2022 – AEMO to hold a 2022 PSFRR industry questions and answer session with stakeholders across the NEM.
- June 2022 – AEMO to publish and respond to submissions received during the industry consultation.
- July 2022 – AEMO to publish the final 2022 PSFRR report.

AEMO is now seeking email submissions on this draft report from all persons interested in the PSFRR. In particular, AEMO invites feedback regarding the methodology, findings and recommendations. Submissions will contribute to the finalisation of the 2022 PSFRR report.

If you would like to make a submission, please email it to psfrr2022@aemo.com.au. Written submissions will be accepted until 5.00 pm (AEST) 17 June 2022.

Submissions will be published on AEMO's website. Please indicate to AEMO if there are any parts of your submission you would like kept confidential, with reasons why.

2 Scope of 2022 PSFRR

2.1 Study overview

The 2022 PSFRR review studies were carried out in PSS®E and considered historical and future operating scenarios using both full OPDMS and simplified NEM models. The details of network, dynamics, SPS, DPV, UFLS and OFGS models used for the studies are detailed in Appendix A3. Appendix A3 also covers the methodology used for historic and future studies, modelling assumptions and study limitations, as well as details of network augmentations considered in the assessment.

2.2 Contingency events considered in the review

AEMO collaborated closely with the primary TNSPs from all regions to identify the key non-credible contingency events for consideration in the 2022 PSFRR. More details on how AEMO assessed and categorised continency events can be found in Appendix A.1. The key contingencies considered in the 2022 PSFRR for historical and 2027 future scenarios are listed in Table 2.

Table 2 Contingency events studied during the 2022 PSFRR

Contingency number	Contingency description	Historical studies	2027 future studies	
		with historical OPDMS time stamps	with full OPDMS model	with simplified NEM model
1	Separation of SA through loss of Heywood – South East 275 kilovolts (kV) lines considering potential operation with fewer than two synchronous generators prior to delivery of Project EnergyConnect (PEC) stage 2	✓	✓	
2	Separation of SA through loss of Moorabool – Mortlake (MLTS-MOPS) and Moorabool – Haunted Gully (MLTS-HGTS) 500 kV lines	✓	✓	
3	Separation of Queensland (QLD) through loss of Queensland – New South Wales Interconnector (QNI) considering the increased flows following QNI upgrades	✓		✓
4	Loss of both 275 kV lines between Calvale and Halys with upgraded Central Queensland (CQ) and South Queensland (SQ) Special Protection Scheme (SPS)	✓	✓	
5	Loss of the Victoria – New South Wales Interconnector (VNI)	✓		✓
6	Fault of the Mount (Mt) Lock 275 kV busbar in SA	✓		
7	Loss of both Dederang to South Morang (DDTS – SMTS) 330 kV lines with updated Interconnector Emergency Control Scheme (IECS)	✓		
8	Loss of Columboola – Western Downs 275 kV lines resulting in large loss of load leading to possible instability across QNI and over-frequency event in QLD	✓		
9	Simultaneous loss of multiple Loy Yang A generating units	✓		
10	Loss of Ballarat – Waubra 220 kV line followed by Balranald – Darlington Point 220 kV (x5) line or	✓		

Contingency number	Contingency description	Historical studies	2027 future studies	
		with historical OPDMS time stamps	with full OPDMS model	with simplified NEM model
	Darlington Point - Wagga 330 kV (63) line within 30 minutes			

Key notes regarding the assessment approach:

- Historical cases OPDMS time stamps: PSS®E cases generated from OPDMS for NEM system corresponding to the system operation conditions for a given time stamp. The historical snap shots were selected from 1/1/2019 to 1/1/2020. Generation and load dispatch in OPDMS study cases were unaltered.
- Future cases with full OPDMS models: PSS®E study cases with network similar to OPDMS network but augmented with network upgrades, such as PEC and Queensland – New South Wales Interconnector (QNI). More details on the upgrades considered and dynamic models used are included in Appendix A3.
- Future studies with simplified NEM model: Mainland NEM regions are represented in simplified model with lumped regional generations. For details of the model setup, network upgrades considered, dynamic models used and other assumptions please see Appendix A3. Appendix A3 also outlines the key limitations of the simplified NEM model.
- Operation of South Australia with fewer than two synchronous units, PEC and QNI upgrades are included only in 2027 future studies.
- The 2027 future scenarios used the Draft 2022 ISP *Step Change* forecast data to set up study cases relevant to each contingency.
- Contingencies 6 to 10 were excluded from future scenario studies as it is not expected that the original historical study observations will be altered.

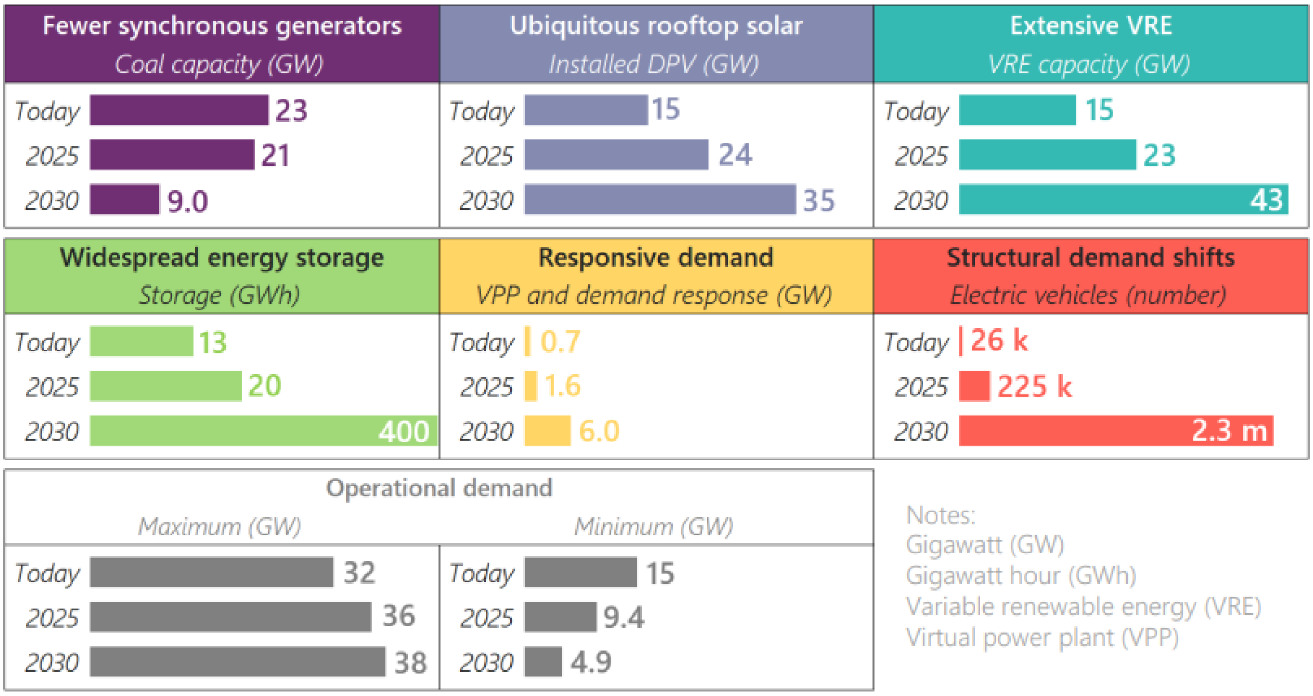
3 Industry in transition

3.1 Generation mix

Historically, Australia's electricity needs were met by generation from synchronous machines using hydro power, coal, or gas as their primary energy sources. Over the last decade, significant installation of inverter-based variable renewable energy (VRE) generation (mainly wind and solar) has occurred in the NEM, and several ageing coal-fired generating plants have been retired and decommissioned. More recently, several large-scale battery energy storage systems (BESS) have been commissioned, and significantly more BESS capacity is planned for connection to the NEM. In addition, there have been unprecedented developments in the connection of small DER, mainly in the form of DPV, along with a small uptake of distributed small battery storage systems. More grid-connected energy storage projects, mainly battery energy storage and pumped hydro energy storage projects, are being planned and proposed. Generation using stored energy is likely to become vital for managing the intermittency of VRE, as the generation mix continues to transform.

Figure 4 shows anticipated changes to generation and load composition as described in AEMO's Draft 2022 ISP *Step Change* scenario[14].

Figure 4 Anticipated changes to generation and load composition under AEMO's Draft 2022 ISP *Step Change* scenario



[14] AEMO, NEM Engineering Framework Initial Roadmap, December 2021, p5, at https://aemo.com.au/-/media/files/initiatives/engineering-framework/2021/nem-engineering-framework-initial-roadmap.pdf?la=en&hash=258E0F1A2E8E6EE6C00437E75BB170FF.

Table 3 shows the minimum number of synchronous generating units that must be dispatched to maintain power system security at present in normal system conditions, and the minimum number assumed to be required in future for each region[15]. The figure shows the Draft 2022 ISP assumes that, by 2025-26, zero large synchronous generating units will need to be online continuously to maintain power system security in most regions. It must be emphasised that the technical solutions to allow for this outcome have not yet been determined, but it is a useful planning assumption to allow for the identification of potential technical problems and solutions that could arise as the penetration of instantaneous renewables increases. Consistent with other planning studies the 2022 PSFRR has applied market modelling based on AEMO's *Step Change* scenario from the 2022 Draft ISP to project the operational behaviour of synchronous generation units across the NEM and therefore identify potential frequency stability risks.

Table 3 Minimum synchronous generating unit planning assumptions – 2021 Inputs and assumptions workbook

Region	Condition	No. large synchronous units always online[A, C]
New South Wales	Now	≥7
	From 2025-26	≥0
Queensland	Now[B]	≥11
	From 2025-26	≥0
	Post second QNI	≥0
South Australia	Now (synchronous condensers installed)	≥2
	Post Project EnergyConnect	≥0
Tasmania	Now	≥3
	Post Marinus Link	≥3
Victoria	Now	≥5
	From 2025-26	≥0

A. Numbers shown are high-level planning assumptions only, not operational advice. Comprehensive studies with detailed models will be required closer to these time periods as the power system evolves. When assessing system strength and inertia shortfalls, the requirement to always keep minimum units online is relaxed in market modelling in order to determine timing and size of potential shortfalls.
B. Additional smaller synchronous units may be required online to deliver the minimum synchronous machine dispatch for Queensland
C. Future AEMO reports such as the System Strength and Inertia reports may test interim numbers of machines as part of their detailed studies and assessments.

The assumed reduction in the minimum required number of online synchronous generating units poses both challenges and opportunities for the management of frequency risks in the NEM. Managing power system security within the required operating voltage and frequency bands will be challenging. In addition, the fault ride-through capabilities of IBR under reduced fault level and system strength will be an issue, particularly following non-credible contingencies. The impacts of reduced fault levels on power system security, protection devices and generator fault ride-through need to be evaluated.

[15] From AEMO, 2021 Inputs and assumptions workbook.xlsx, Power System Constraints sheet, 10 December 2021, at https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-and-assumptions-workbook.xlsx?la=en.

Conversely some new plant, such as battery energy storage systems (BESS), have been shown to respond rapidly to power system frequency changes and are contributing positively to maintain the frequency closer to the nominal value, following power system disturbances[16].

Additionally, the Australian Energy Market Commission's (AEMC's) 2020 mandatory PFR rule has re-established effective frequency control within the normal operating frequency band in the NEM, reversing a trend of deteriorating NEM frequency control for multiple years prior[17].

3.2 Network augmentations

At present several network augmentations and the construction of new interconnectors and transmission lines are progressing. The statuses of the major transmission network projects as at the time of preparing the 2022 PSFRR are as follows:

- QNI upgrade – anticipated to increase the transfer capability of QNI to up to 1,450 MW from Queensland to New South Wales, and 950 MW from New South Wales to Queensland [18]. this project is planned to commence commissioning in June 2022.
- Project Energy Connect (PEC) – planned to be delivered in two stages, with final commissioning due in the second half of 2024, a new double circuit alternating current (AC) transmission corridor from northern South Australia to south-west New South Wales is anticipated to have a transfer capacity of 800 megawatts (MW) in both directions.
- Victoria – New South Wales Interconnector (VNI) Upgrade – procurement and construction is underway, with a planned completion in late 2022. this is planned to increase VNI transfer capability by up to 170 MW, via several plant additions and upgrades to mitigate different constraints that presently limit VNI transfer[19].
- Western Victoria Renewable Integration Regulatory Investment Test for Transmission (RIT-T) – anticipated to be completed by the end of 2025, this will enable greater transfer of generation from western Victoria to Melbourne by building a new 220 kilovolts (kV) double circuit transmission line from Bulgana to a new terminal station north of Ballarat, and a new 500 kV double circuit from north of Ballarat to Sydenham[20]. The non-credible loss of the proposed 500 kV lines during period when the new 500 kV lines flow exceeds the limits of the parallel 220 kV lines, could result in multiple line losses. AEMO Vic planning is advised to consider this risk in the planning process.
  - Note that while the Western Victoria Renewable Integration RIT-T upgrade was modelled in relevant studies so that that its impact on power flows was captured, the non-credible trip of the new lines was not studied. The Western Victorian Renewable Integration RIT-T did not identify any non-credible contingencies to be of such a high probability that it would impact the RIT-T assessment. Nevertheless, AEMO (in its role

[16] AEMO, Initial operation of the Hornsdale Power Reserve BESS, April 2018, at https://www.aemo.com.au/-/media/Files/Media_Centre/2018/Initial-operation-of-the-Hornsdale-Power-Reserve.pdf.

[17] AEMO, Enduring primary frequency response requirements for the NEM, August 2021, at enduring-pfr-requirements-for-the-nem-technical-white-paper.pdf (aemo.com.au)

[18] Table 2.2 of the QNI Upgrade Project Test Program for Inter-Network Tests, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/qld-to-nsw-interconnector-qni-upgrade/final-inter-network-test-program-document.pdf?la=en.

[19] Section 3.3.4 of the 2021 Victorian Annual Planning Report, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2021/2021-victorian-annual-planning-report.pdf?la=en.

[20] Section 3.3.2 of the 2021 Victorian Annual Planning Report.

as the Victorian transmission planner) has and will continue to monitor the situation as the project progresses through the Victorian control scheme review process and Victorian Annual Planning Report.

3.3 Distributed energy resources

DER are now a significant component of the power system, supplying up to 43% of underlying demand in the NEM mainland[21] in some periods during 2021, projected to grow to up to 70-80% of underlying demand for some periods by 2025. DPV has already supplied up to 92% of underlying demand in some periods in South Australia and could supply more than 100% of underlying demand in some periods by late 2022 in some NEM regions.

3.3.1 DER compliance with AS/NZS4777.2:2020

Preliminary findings on compliance with AS/NZS4777.2:2020

In 2018, AEMO identified that a large proportion of DPV can disconnect following power system disturbances, and that this would likely cause power system security issues as DPV installations continued to grow[22,23,24]. Since then, AEMO has worked with the Standards Australia committee (June 2019 to Dec 2020) to improve AS/NZS4777.2, aiming for distributed inverters to ride through power system disturbances with similar abilities to large-scale generators[25]. The new standard was published in December 2020 and became mandatory for all new distributed inverters installed from 18 December 2021.

Preliminary evidence suggests that most inverters that are properly set to the new AS/NZS4777.2:2020 standard demonstrate the required ride-through behaviour in laboratory bench testing[26]. Changes to the standard included provisions for reduced manual handling of input settings by the installer, which was intended to improve overall compliance of DER systems in the field. Unfortunately, preliminary data shows high levels of non-compliance[27]. Seven manufacturers with significant market share in Australia (representing in aggregate more than 60% of new installations in Q1 2022) have provided data to AEMO on the settings applied to their inverters installed in Australia during January to March 2022. In aggregate, the data samples suggest that only 35% of installations have been installed in accordance with the new AS/NZS4777.2:2020.

The majority of inverters installed with incorrect settings were installed in accordance with the older, 2015 standard. AEMO's discussions with manufacturers, and commissioning notes collected by the University of New South Wales (UNSW) during their bench testing of inverters suggest that similar findings are likely from a broader range of manufacturers, as most retained the old settings in their menu options presented to installers.

[21] The NEM mainland is defined as the interconnected system of Queensland, New South Wales, Victoria and South Australia.

[22] AEMO (10 January 2019) Final Report – Queensland and South Australia system separation on 25 August 2018, at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2018/qld---sa-separation-25-august-2018-incident-report.pdf?la=en&hash=49B5296CF683E6748DD8D05E012E901C.

[23] AEMO (April 2019) Technical Integration of Distributed Energy Resources, at https://aemo.com.au/-/media/files/electricity/nem/der/2019/operations/technical-integration-of-der-report.pdf?la=en&hash=65EAE8BA3C64216F760B16535CE2D3ED.

[24] AEMO (May 2021) Behaviour of distributed resources during power system disturbances, at https://aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf?la=en&hash=BF184AC51804652E268B3117EC12327A.

[25] AEMO, AS/NZS4777.2 – Inverter Requirements standard, at https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/standards-and-connections/as-nzs-4777-2-inverter-requirements-standard.

[26] Preliminary bench testing results for seven inverters delivered by UNSW Sydney as part of an ARENA-funded collaboration, "Addressing Barriers to Efficient Renewable Integration", at https://research.unsw.edu.au/projects/addressing-barriers-efficient-renewable-integration.

[27] Analysis conducted by UNSW as part of an ARENA-funded collaboration, "Project MATCH", at http://www.ceem.unsw.edu.au/project-match.

AEMO is working with the Clean Energy Council, the Clean Energy Regulator, inverter manufacturers, DNSPs, the Australian Energy Regulator and state governments to identify and implement rapid measures to improve compliance with AS/NZS4777.2:2020 in the field. This includes:

- Working with product manufacturers to remove outdated standards from their product menus.
- Greater training and education for installers.
- Processes for increasing visibility of inverter settings in the field, and increasing the prevalence of remote update capabilities.
- Application of escalating penalties for installers who apply incorrect settings.
- Long-term enduring arrangements with clear roles and responsibilities around assessing and enforcing compliance.

AEMO welcomes engagement on this issue. Interested parties should contact DERProgram@aemo.com.au.

3.3.2 DER impacts on UFLS

UFLS is an important last resort safety net, protecting consumers from black system events when severe generation contingencies occur. It involves the automatic disconnection of load to rebalance supply and demand in less than one second.

Increasing levels of generation from DPV is reducing the power flow on UFLS circuits. This reduces the effectiveness of UFLS, because reduced net load is available to be tripped. With even further growth in DPV generation, UFLS circuits can operate in reverse flows, which means that in the absence of intervention, UFLS relays will act to disconnect circuits that are net generators (rather than net loads), exacerbating the supply demand imbalance when they activate following an under frequency event.

Total aggregate UFLS load in South Australia reached -110 MW (-152 MW in the distribution network) on 21 November 2021 due to high levels of DER generation. This indicates that the majority of circuits in the South Australia UFLS scheme are now in reverse flows during some periods. Risks associated with management of a SA separation at the HYTS when importing into South Australia are being managed at present through constraints[28].

Other regions are also trending toward very low levels of UFLS availability with the ongoing growth of DPV, as demonstrated in Table 4. The level of UFLS load available has been calculated as a percentage of the total underlying load in the region to provide a measure of the scale of UFLS response available compared with the size of the power system. The NER indicate that reserves should be adequate to arrest impacts of significant multiple contingency events 'affecting up to 60% of the total power system load' (NER clause 4.3.1(k)). It is difficult to apply this metric to today's power system, but AEMO believes it is necessary to consider the underlying power system load. As shown in Table 4, all mainland regions now have UFLS levels below 60% of total underlying load during some periods, and this is projected to fall further in the next few years, to as low as 12% of underlying load in VIC by 2023.

[28] AEMO (October 2020) Heywood UFLS constraints, at https://aemo.com.au/-/media/files/initiatives/der/2020/heywood-ufls-constraints-fact-sheet.pdf?la=en&hash=066F80AE0EE3CF9701A0509818A239BB.

Additionally, legacy DPV demonstrates under-frequency disconnection behaviour when frequency falls below 49 Hz[29,30], which effectively increases the contingency size when it is generating. This is a significant contributing factor that further exacerbates difficulties in arresting power system frequency during severe under frequency disturbances.

Table 4 Minimum net UFLS load, as a percentage of total underlying load in the region

Region	2020 (Actuals)	2023 (Projected)
SA	Negative	Negative
VIC	30%	12%
QLD	41%	29%
NSW	46%	31%

More detail on AEMO's assessment of the status of UFLS in South Australia is discussed in the 2020 Power System Frequency Risk Review[31].

More information about UFLS in Victoria, Queensland and New South Wales is available in AEMO's reports to NSPs[32].

3.3.3 UFLS remediation in South Australia

Table 5 summarises the suite of measures AEMO, SAPN and ElectraNet are undertaking to restore UFLS capability and mitigate risks in South Australia Further details are provided in the following sections.

Table 5 Measures to remediate South Australian UFLS

Action	Status	Estimated completion
Addition of new loads to the UFLS	• SAPN has added about 100 MW of distribution-connected load. • ElectraNet has added 150-230 MW of transmission-connected load. • Almost all SA load is included in the UFLS scheme.	Completed March 2022
Dynamic arming of UFLS relays in reverse flow	• AEMO advice provided to SAPN (March 2021). • SAPN submission to AER ongoing; implementation to follow if approved. Constraints on the Heywood Interconnector will account for removal of reverse flowing circuits through incremental updates to SAPN SCADA feed of total UFLS load available.	2022-25
Adaptive arming	• AEMO advice to SAPN in preparation. • Expected rollout in parallel with dynamic arming implementation, at sites where feasible and low-cost.	2022-25
Delayed UFLS	• AEMO advice to SAPN in preparation. • Expected rollout in parallel with dynamic arming implementation.	2022-25

29 AEMO (May 2021) Behaviour of distributed resources during power system disturbances, at https://aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf?la=en&hash=BF184AC51804652E268B3117EC12327A.

30 AEMO (April 2016) Response of existing PV inverters to frequency disturbances, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/reports/response-of-existing-pv-inverters-to-frequency-disturbances-v20.pdf.

31 AEMO (July 2020) 2020 Power System Frequency Risk Review – Stage 1, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/psfrr/stage-1/psfrr-stage-1-after-consultation.pdf?la=en&hash=A57E8CA017BA90B05DDD5BBBB86D19CD.

32 AEMO, Adapting and managing Under Frequency Load Shedding at times of low demand, at https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/operations/adapting-and-managing-under-frequency-load-shedding-at-times-of-low-demand.

Action	Status	Estimated completion
Rebalancing and optimisation of SA UFLS settings	• Studies ongoing. Present settings appear adequate.	Ongoing
Emergency Under Frequency Response (EUFR) Procurement	• SAPN discussion paper and industry workshop completed in February 2022. • Expression of interest under development with request for proposal to follow.	2022-23

Dynamic arming

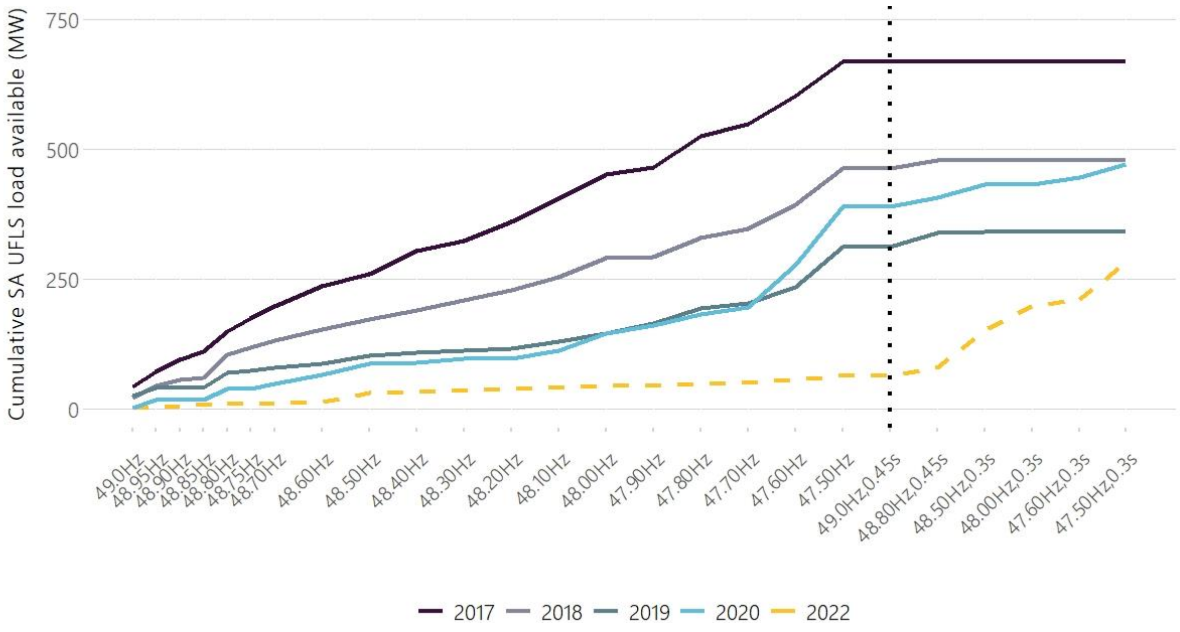
Dynamic arming involves the upgrade of UFLS relays to automatically disarm UFLS tripping when the circuit is in reverse flows, increasing the net available UFLS load and mitigating the potential for 'reverse' UFLS operation that exacerbates an under frequency disturbance, rather than helping to correct it. AEMO is working with SAPN to introduce dynamic arming at a large proportion of UFLS circuits in South Australia[33]. Preventing increasing levels of reverse flows on the UFLS is a prerequisite to any other actions to restore emergency frequency response to required levels.

UFLS settings optimisation

AEMO has undertaken analysis of the South Australia UFLS load profile during various key periods, comparing historical UFLS load profiles from 2017 to 2020 against a forecast 2022 profile, which includes new UFLS loads, partial implementation of dynamic arming, and forecast growth in DPV and underlying load in alignment with AEMO's 2021 Electricity Statement of Opportunities (ESOO) *Step Change* forecast. Figure 5 compares the historical (solid lines) and forecast (dashed yellow line) profiles in a typical low UFLS load period. UFLS loads with relays on a longer pickup time (>0.3 seconds [s]) are shown to the right of the dotted line, to distinguish them from loads with shorter pickup times (0.15 s).

[33] AEMO 2021, *South Australian Under Frequency Load Shedding – Dynamic Arming: Implementation investigation*, at https://aemo.com.au/-/media/files/initiatives/der/2021/south-australian-ufls-dynamic-arming.pdf?la=en&hash=C82E09BBF2A112ED014F3436A18D836C.

Figure 5 South Australia UFLS profile in a typical low UFLS load period



Despite the many changes implemented, the overall UFLS load profile in 2022 appears to remain relatively balanced in most periods. Despite addition of a large proportion of new UFLS loads in the lowest frequency bands, the profile remains relatively linear. Dynamic arming also appears to restore load relatively equally across the frequency bands. AEMO's present assessment is that there is no urgent requirement to undertake a full update of South Australia's UFLS settings, although this will be continually reassessed as further changes are implemented, and as further data becomes available.

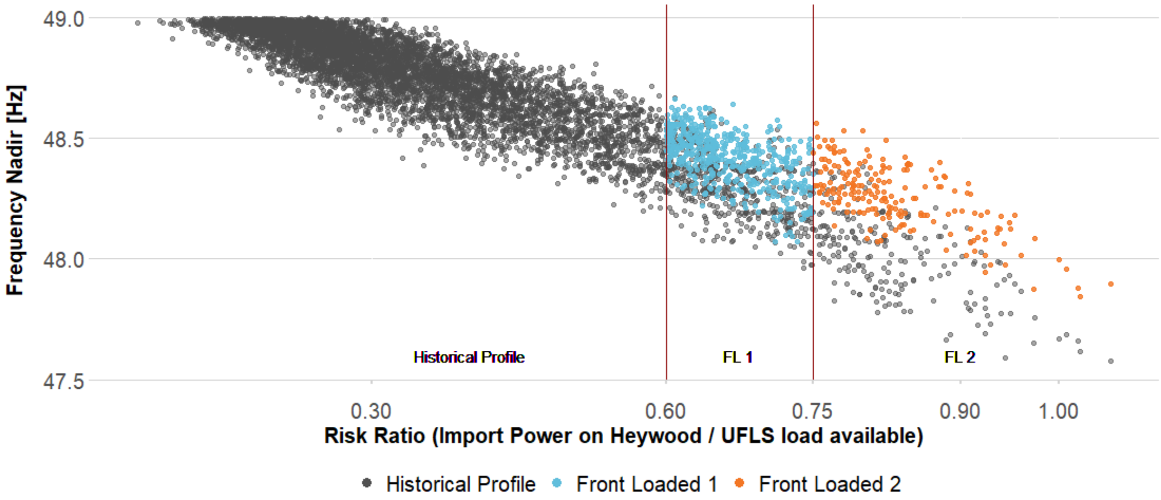
Adaptive arming

The upgrade of relays to introduce dynamic arming (blocking of UFLS relays when circuits are in reverse flows), also enables the further capability for adaptive arming: UFLS relays changing frequency trip settings in real time based on pre-determined criteria (summarised below).

AEMO's analysis indicates that frequency outcomes can be improved following the double circuit loss of the Heywood Interconnector if a portion of the available UFLS load is shifted to higher frequency settings (front loading) where interconnector flows are high, and available UFLS load is low. Over-shoot risks (excessive UFLS tripping leading to over frequency) can be managed by only front-loading the UFLS profile when the ratio of import power on Heywood to the UFLS load available is greater than 60% (and potentially further increasing the front-loading when this ratio exceeds 75%). Figure 6 illustrates the modelled improvement in frequency nadir (comparing grey dots for static settings, versus coloured dots for adaptive settings) following the double circuit loss of Heywood.

AEMO is consulting with SAPN on the implementation of adaptive arming across the region. Preliminary analysis suggests the benefits of adaptive arming might be limited since its main action would be to alleviate UFLS constraints on the Heywood Interconnector, and the binding of these constraints does not often lead to high market costs. Adaptive arming should therefore only be implemented if it can be achieved at low cost.

Figure 6 Simulated frequency nadir following Heywood loss for periods in 2019-20

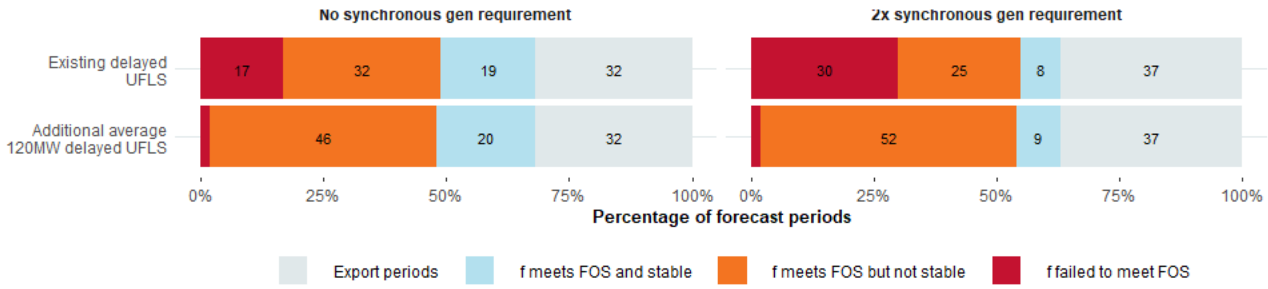


Delayed UFLS

The Frequency Operating Standard (FOS) requires frequency in the South Australia island to recover to 49 Hz within two minutes, and to 49.5 Hz within 10 minutes, following a non-credible separation event. This needs to be achieved with autonomous systems, since control room intervention within this timeframe cannot be guaranteed. As shown in Figure 7, AEMO's analysis indicates that these FOS requirements are unlikely to be met 20-30% of the time and could be at risk of not being met around 50% of the time.

Increasing the amount of delayed UFLS (load blocks that trip if frequency is below prescribed thresholds for an extended duration) significantly reduces the incidence of failures to meet the FOS. By adding an additional annual average of 120 MW of total load to the delayed UFLS scheme, the incidence of failures is estimated to reduce from 17-30% to 1-2%, as shown in Figure 7. The delayed UFLS blocks are triggered by a sustained under frequency condition of frequency below 49.5 Hz for time settings in 15 s increments from 90 s to 300 s. SAPN has advised AEMO that there is sufficient load behind UFLS relays capable of adding the additional delayed setting to achieve this. It is expected that the commissioning of the delayed settings can be implemented alongside dynamic arming upgrades. AEMO is preparing advice to SAPN for implementation of these settings.

Figure 7 Frequency recovery outcomes (2022-23 and 2023-24)



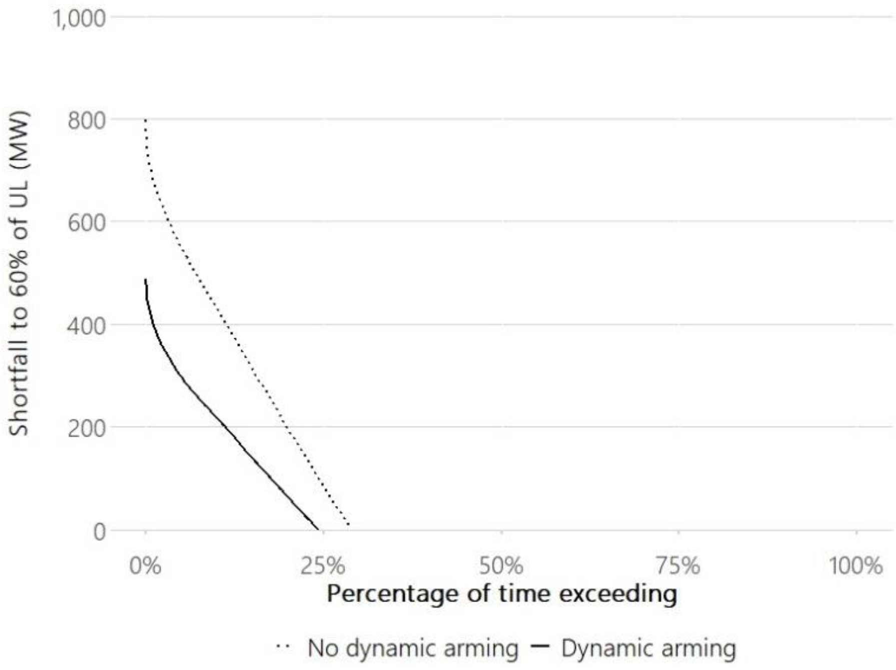
Studies were completed under two dispatch scenarios: a scenario with no requirement for synchronous generating units to remain online, and a scenario with a minimum requirement for two synchronous generating units remaining online. Findings were similar under these two scenarios.

Emergency Under Frequency Response (EUFR) Procurement

The introduction of dynamic arming prevents the UFLS scheme from operating in reverse and exacerbating contingencies, but is only expected to restore net UFLS load to 150 MW to 200 MW during periods of low load.

AEMO's modelling suggests that emergency under frequency response in South Australia should be in the order of 600-1,200 MW[34]. This means a UFLS shortfall could still exist up to 25% of the time during 2023-24, as shown in Figure 8, occurring primarily during high DPV generation.

Figure 8 Total net UFLS load in South Australia – shortfall to 60% of underlying load (FYE24)



Complementary work to assess the total amount of emergency under frequency response required is ongoing, but for this preliminary assessment, UFLS levels have been compared to an assumed requirement of 60% of total underlying load. AEMO, SAPN and ElectraNet are collaborating to procure additional emergency under frequency response. SAPN and AEMO are collaborating on the development of specifications for a new service to deliver emergency under-frequency response, which could be either a reduction in load, an increase in generation, or both. SAPN intends to seek expressions of interest from industry during 2022, for service implementation in late 2022. Interested parties should contact SAPN

3.3.4 UFLS remediation in other regions

AEMO has also commenced an investigation and remediation of UFLS in Victoria, Queensland and New South Wales, as summarised in Table 6.

Table 6 UFLS remediation in Victoria, Queensland and New South Wales

Region	Action	Timeline/status
VIC	Assessment of load in UFLS scheme in 2019 and 2020, and forward projection based on forecast growth in DPV: 2021 to 2023.	Analysis completed and delivered to NSPs (August 2021)
	Update analysis on UFLS load in VIC to include 2021, forward projection 2022 to 2025.	Underway, target May 2022
	Determine emergency under-frequency response requirements for VIC in low demand periods	Underway, target December 2022

[34] AEMO (May 2021) South Australian Under Frequency Load Shedding – Dynamic Arming, Section 2, at https://aemo.com.au/-/media/files/initiatives/der/2021/south-australian-ufls-dynamic-arming.pdf?la=en&hash=C82E09BBF2A112ED014F3436A18D836C.

Region	Action	Timeline/status
	Collaboration with NSPs to investigate options for remediation, and develop remediation plan	Underway, target December 2022
QLD	Assessment of load in UFLS scheme in 2019 and 2020, and forward projection based on forecast growth in DPV: 2021 to 2023.	Analysis completed and delivered to Network Service Providers (December 2021)
	Determine emergency under-frequency response requirements for QLD in low demand periods	Underway, target 2023
	Collaboration with NSPs to investigate options for remediation	Underway, plan in development
NSW	Assessment of load in UFLS scheme in 2019 and 2020, and forward projection based on forecast growth in DPV: 2021 to 2023.	Analysis completed and delivered to NSPs (December 2021)
	Establish collaboration with NSPs on UFLS remediation	Target 2023

3.4 Managing frequency in 2022-27

The rapid transformation of the power system creates several challenges for managing power system frequency within the ranges specified in the FOS. Management of frequency in different frequency ranges is discussed below:

- Normal operating frequency band (NOFB): The PFR provided by synchronous generators, IBR and BESS is vital to regulation of power system frequency within the NOFB under normal operating conditions, supported by regulation frequency control ancillary services (FCAS). The FCAS provided by retiring fossil fuel plants will need to be sourced from the new sources such as BESS.
- Operational frequency tolerance band (OFTB): The regulation of power system frequency within the OFTB is required for credible contingencies, with contingency FCAS markets being the key control mechanism. Meeting the FOS requirements within the containment and stabilisation bands in terms of frequency magnitude and periods will be challenging. The introduction of new very fast FCAS markets from late 2023 will assist in managing power system frequency following credible contingencies, allowing for the expected loss of inertial and frequency response support provided by conventional generation resources.
- Extreme frequency excursion tolerance limit (EFETL): AEMO must use ‘reasonable endeavours’ to limit power system frequency to within the EFETL following non-credible contingencies. EFCSs are a key tool to manage power system frequency within the EFETL. At present, UFLS is in operation in all regions, and OFGS is in operation in South Australia and Tasmania. In future, there will be a reduction in inertia, FCAS availability, and UFLS availability due to underlying DPV in UFLS feeders. To manage non-credible contingency frequency excursions, UFLS remediation and OFGS schemes will need to be further considered.

4 Review of incidents

AEMO reviews power system incidents of significance in accordance with clause 4.8.15 of the NER, referred to as reviewable operating incidents[35].

Table 7 summarises the key high level criteria AEMO uses to identify whether an incident is reviewable, and categories used to determine the reporting approach (preliminary and final report for major incidents, or final report only). Consistent with the AEMC guidelines for identifying reviewable incidents[36], AEMO may also undertake a review of any other events considered to be of significance.

Table 7 Reviewable incident criteria

Category	Description	Network	Security	Frequency	Voltage	Loss of load/generation
Not reviewable	Credible event or non-credible event that does not impact critical transmission element	Credible contingency	Not insecure for < 30 mins	Within FOS requirements	Within standards	No load shedding (other than disconnections/load shake-off) No loss of generation due to operation of over-frequency protection
			Not non-satisfactory < 5 mins			
Reviewable (Minor)	Noteworthy event requiring AEMO to prepare a report (or AEMO chooses to review an event or systemic issue)	Non-credible contingency or multiple contingency	Insecure > 30 mins	Frequency outside 49 – 51Hz (NEM) or 48 - 52Hz (Tas)	Minor voltage impacts within standards	No automatic or manually initiated load shedding Loss of generation due to operation of over-frequency protection
Reviewable (Major)	Significant event requiring AEMO to prepare a report, impacting stakeholder confidence or adverse media exposure	Non-credible or multiple contingency resulting in separation between regions	Non-satisfactory > 5 mins		Voltage collapse resulting in local/widespread transmission system black	Automatic UFLS action or AEMO directed load shedding (other than as contracted)

[35] See NER chapter 4 (4.8.15) at https://energy-rules.aemc.gov.au/ner/379.

[36] See https://www.aemc.gov.au/sites/default/files/content/d8f865db-f9d7-4c08-b188-5e4dc05968e1/Issues-Paper.pdf.

For an incident to be reviewable, it must be a noteworthy or significant event on the power system and generally include an impact to the power system security, frequency, voltage or result in load disconnection/loss. Based on its experience reviewing power system incidents, AEMO has observed that unexpected power system impacts are often identified during power system events. These often increase an event's overall severity; examples of such unexpected impacts are:

- Protection mal-operation.
- Unexpected load disconnection.
- DPV disconnection.
- Generators failing to ride through faults correctly.

AEMO has considered these types of additional power system impacts when identifying contingencies for study in this year's PSFRR.

4.1.1 Summary or reviewable incidents since 2020 PSFRR

Since the last risk review there have been four major and 51 minor reviewable incidents:

- 13 incidents were initiated by equipment failure.
- 14 incidents were initiated by protection, control or signalling equipment mal-operation.
- 8 incidents were initiated by lightning.
- 7 incidents were initiated by bushfires.

Full details of these reviewable incidents can be found in the published incident reports available on AEMO's website[37]

[37] Please see https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/power-system-operating-incident-reports

5 Study results and observations

This chapter describes the priority event studies carried out for the 2022 PSFRR. These non-credible contingency events were studied for historical scenarios, and depending on the findings, for future study scenarios.

Historical study case selection

Historical conditions were selected for study which represent the operational boundaries of the power system relevant to each contingency. To identify those boundary system conditions, 1.5 years[38] of 30 minute historic operational data including interconnector and line flows, regional demand, system inertia, generation dispatch, DPV generation and UFLS/OFGS availability were analysed. System conditions for study were then selected to maximise the likelihood of a large frequency excursion for each contingency. The primary consideration in case selection was maximum flow on the circuits affected by a particular contingency event. For example, historical study cases where HIC imports/exports (and therefore HIC flow) were at their highest levels were used in SA Separation from HYTS studies. Cases were also identified to maximise/or minimise (as appropriate) other key system parameters (such as high/low DPV levels and high/low regional demand) at times of maximum line flows. As these other parameters have a smaller impact on system frequency outcomes, specific cases maximising these other parameters, with reduced contingent line flows, were not selected for study.

Future study case selection

Future studies were carried out in full NEM and simplified NEM models.

The assumptions and data for the future scenario studies with the simplified NEM model are according to the 2027 ISP *Step Change* projections. The ISP *Step Change* scenario forecast for 2027 was used for the projected demand, DPV penetration, UFLS availability and IBR capacities for each region. The following scenarios of generation dispatch were considered for the studies:

- For SA, cases with 0, 1 and 2 synchronous generating units in-service were considered, noting that all 4 synchronous condensers were online for all studies.
  - For scenarios with 1 synchronous generating unit online, a Torrens Island A or B gas unit was dispatched.
  - For scenarios with 2 synchronous generating units online, either one Pelican Point gas unit and the Pelican Point steam unit were dispatched, or two Torrens Island B gas units were dispatched.
  - The units online in the remaining NEM were as per Scenario 2, described below.
- For the remaining regions, three different scenarios of synchronous generation dispatch were considered:
  - Scenario 1: The current minimum system strength combination less any decommitted units, which were replaced with other available units of a similar size[39].

[38] The period considered for historical snapshots ran from 01/01/2019 to 01/07/2020.

[39] https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2022/update-to-2021-system-security-reports.pdf?la=en

- Scenario 2: The current minimum system strength combination less any decommitted units. The system strength gap was assumed to be filled with a solution that does not provide any additional inertia to the power system[40].
- Scenario 3: Coincidental 99th percentile availability of synchronous generating units in each region estimated based on AEMO's *Step Change* scenario from the 2022 Draft ISP forecast[40].

The list of generators considered under different scenarios are included in Table 8. The generators are represented by equivalent lumped unit according to the net inertia of the combinations for each region.

Table 8 List of generators assumed for different scenarios

Scenario	NSW	QLD (South)	QLD (Central)	QLD (North)	VIC
1	6 units (4 Bayswater, 2 Mt Piper)	5 units (1 Wivenhoe, 3 Darling Downs, 1 Millmerran)	7 central (3 Stanwell, 4 Gladstone)	3 northern (1 Kareeya, 1 Barron Gorge, 1 Mt Stuart)	6 units (3 Loy Yang, 2 Murray, Newport)
2	5 units (3 Bayswater, 2 Mt Piper)	5 southern (1 Wivenhoe, 3 Darling Downs, 1 Millmerran)	5 central (2 Stanwell, 3 Gladstone)	3 northern (1 Kareeya, 1 Barron Gorge, 1 Mt Stuart)	6 units (3 Loy Yang, 2 Murray, Newport)
3	3 units(1 Bayswater, 2 Mt Piper	4 southern (1 Tarong, Kogan Creek, 2 Millerran)	5 central (3 Stanwell, 2 Gladstone)	1 northern (1 Kareeya)	4 units (4 Loy Yang)

The following additional assumptions were made for all future studies:

- Following the public announcement of the closure of Eraring in 2025, the Eraring generating units were removed from the projection data.
- The simplified NEM model used for the studies of the future scenarios did not include PEC. This allows the present SA UFLS and constraints under SA regulations[41] to be used to limit HIC flows.
- No FFR responses from BESS are assumed, except for Hornsdale BESS, which is assumed to have the current minimum contracted amount of 70 MW of raise FFR and 40 MW of lower FFR.

5.1 Introduction to historical and future scenario studies

The studies were conducted in two major groups: historical and future scenarios. This section describes details of contingencies and the approaches used for the two categories of studies and organisation of results and observations.

5.1.1 Historic studies

Priority contingency events listed in Section 2.2 were assessed for historical study cases. Studies were undertaken using the full NEM model based on selected historical power system snapshots from AEMO's Operational Data Management System (OPDMS). Further details regarding the methodology for historical study cases is provided in Appendix 3.1.

[40] https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios

[41] *Electricity (General) Regulations 2012*, regulation 88A.

Contingencies 1 to 4, 7 and 8 were found to have a significant power system impacts leading to recommendations to manage the identified risks. Hence, these contingencies are included in section 5.2 to section 5.7 of this report. The remaining contingencies (for which there are no major recommendations) are discussed in Appendix A5.

For SA separation historical studies, SA Hornsdale BESS is assumed to have the current minimum contracted amount of 70 MW of raise Fast Frequency Response (FFR) and 40 MW of lower FFR.

5.1.2 2027 – future studies

Historical study results indicate that the outcomes of contingencies 1 to 5 will be impacted by future demand, synchronous generation availability, network augmentation, IBR generation, DPV growth and the availability of UFLS. Hence, contingencies 1 to 5 were also selected for assessment for future scenarios. Future studies were carried out using both the full OPMDS network model and simplified NEM models. The details of contingencies selected for studies in these network models are described below.

Future studies in full OPDMS model

The following contingencies were carried out for future scenarios using the full NEM OPDMS models:

1. Separation of SA through loss of Heywood – South East 500 kV lines with PEC Stage 2 and QNI upgrades and considering the increased interconnector flows following the upgrades.
2. Separation of SA through loss of Moorabool – Mortlake and Moorabool – Haunted Gully 500 kV lines with PEC Stage 2 and QNI upgrades and considering the increased interconnector flows following the upgrades.
4. Loss of both 275 kV lines between Calvale and Halys with WAMPAC[42] and considering the increased flows following QNI upgrades.

Future studies in simplified NEM models

The following contingencies were carried out for future scenarios using the simplified NEM models[43]:

1. Separation of QLD through loss of QNI considering the increased flows following QNI upgrades and 2027 generation step change dispatch scenarios.
2. Non-credible loss of VNI considering the increased flows following QNI upgrades and 2027 generation Step Change dispatch scenarios. Non-credible separation of VNI is very remote and included in the review only for illustrative purposes.

5.1.3 General study notes

Acceptance criteria used

Failure criteria

- Any results violating the FOS are reported as failure cases in this report.

[42] See Section 5.5 for an explanation of what WAMPAC is.

[43] PEC is not included in the simplified NEM model.

Observations

Results which include any of the following are highlighted as observations in the report:

- Any results with frequency excursions close to violation of the FOS.
- Any results with RoCoF[44] exceeding 2 Hz/s in any region.
- Any results where the non-credible loss of an inter-connector leads to the loss of another interconnector.
- Specific recommendations were made in the report to manage the risks identified in all failure cases.

Observations are included in the report as flags for future monitoring for any escalated risks.

Overview of study results tables

Each identified non-credible contingency event has been studied against a range of power system conditions with each different set represented in an individual study case. The key study power system conditions and corresponding results are summarised in tables. Table 9 has a brief explanation of each table column header.

Table 9 Study results column headers

Variable	Description of the variable in the study case
(Region) operational demand (MW)	Regional operational demand
(Region) (interconnector) import/export (MW)	AC interconnector imports/exports to/from the region
(Region) inertia (MW-s)	Regional inertia of synchronous generator(s) and synchronous condenser(s) online
(Region) underlying UFLS (MW)	Regional total UFLS native load (effective UFLS = underlying UFLS – DPV MW in respective UFLS feeders)
OFGS available (MW)	Total OFGS available (where applicable to the study case)
(Region) DPV (MW)	Total DPV generation in the region
(Region) renewables (MW)	Regional wind and solar (excluding DPV) generation
Freq Nadir range (Hz)	Regional minimum simulated frequency (does not include sharp spikes)
RoCoF (Hz)	Regional maximum RoCoF observed in the simulation (300 ms frequency data window is used to calculate RoCoF)
%UFLS Tripped	Percentage ratio of UFLS tripped to UFLS that was available in the case
Total DPV tripped (MW)	Sum of the DPV tripped in the UFLS feeders and the DPV tripped on its own protection
% DPV tripped	Percentage ratio of DPV tripped to DPV that was available in the case
Total DPV Tripped on Protection (MW)	Sum of the DPV tripped due to its own protection
SA OFGS generation tripped (MW)	Sum of the OFGS tripped in SA

5.2 Contingency 1 – SA separation from HYTS

The 275 kV AC HIC connects the Heywood terminal station in VIC and South East substation in SA. The transfer capacity of the HIC is 600 MW from VIC to SA and 550 MW from SA to VIC. Figure 9 shows the probability of exceedance (PoE) for the power flow from VIC to SA and SA to VIC across the HIC from 1 January 2020 to 31 December 2021. From the figure, HIC flow from VIC to SA exceeded its transfer capacity limit for 1.2 % (210

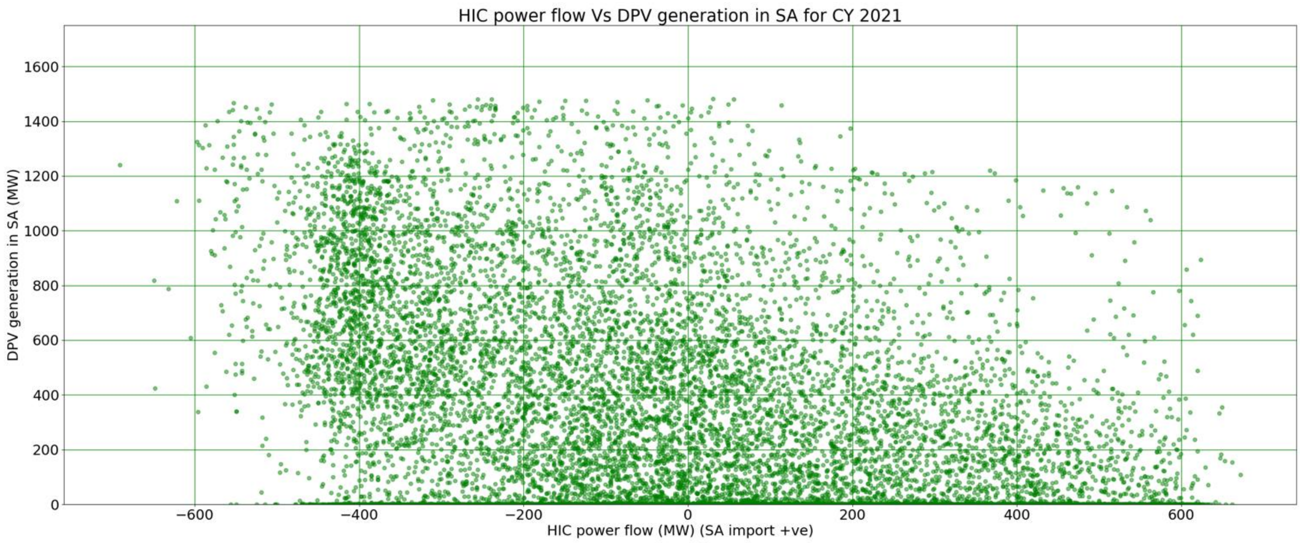
[44] RoCoF was calculated using a 300 ms window

hours) and the flow from SA to VIC for 0.4 % (70 hours) of the data period[45]. There is increased risk of the power system not being in a secure operating state during these periods. HIC flow (vs) SA DPV generation for calendar year 2021 is included in Figure 10. It may be noted that SA DPV generation considered in historical study cases snap shots for the period 1/1/2019 to 1/7/2020 was lower in comparison with the 2021 DPV generation reflecting the DPV growth.

Figure 9 Duration curves for the HIC power flow for 2020 and 2021

Note: positive interconnector flow indicates flow direction from Victoria to South Australia.

Figure 10 HIC flow (vs) SA DPV generation in CY 2021



45 Differences between NEMDE inputs (forecasts of demand and of wind and PV generation output) and real system outcomes (actual demand changes, actual wind and solar generation output and generator ramping action) can cause interconnectors to drift away from their expected operating point. Operating margins are included in dispatch constraints to allow for these factors, however sometimes this interconnector drift may briefly move the interconnector flow above its nominal ratings.

The non-credible separation of SA from HYTS was considered for both import and export conditions. All parameters, results and references to import and export are from the SA perspective, unless otherwise indicated.

5.2.1 SA import – historical cases

Study scenarios

Eleven cases were considered for the historical studies of SA separation through the non-credible loss of the HIC during SA import conditions. Historical cases were selected for study primarily based on maximum/high HIC SA import levels (as high HIC transfers during SA separation are likely to cause the largest system frequency excursions). Coincident with historic high SA imports, SA inertia varied from 9805 to 20870 MW-s and underlying SA UFLS load ranged from 1090 MW to 2401 MW. In addition, coincident with historic high SA imports, maximum DPV and SA renewable generation was 956 MW and 583 MW respectively. The range of power system variables considered for the studies is given in Table 10. Detailed parameters of each case are included in in Appendix A6.1.1.

Table 10 SA separation from HYTS: power system operating points for historical cases (SA import)

SA operational demand (MW)	Total import (HIC + Murraylink) (MW)	HIC import (MW)	SA Inertia (MW-s)	Underlying SA UFLS load (MW)	SA DPV (MW)	SA renewables[A] (MW)
1112-2360	651 - 853	474 - 678	9805 - 20870	1090 - 2401	465 - 956	140 - 583

A. Defined as all wind and solar excluding DPV.

The range of values for key power system variables observed during simulations of all considered cases are summarised in Table 11. More detailed results for individual cases are included in Appendix A6.1.1.

Table 11 SA separation from HYTS: historical cases results (SA import)

SA freq nadir range (Hz)	SA RoCoF (Hz /s)	SA underlying UFLS load tripped (MW)	SA % underlying UFLS load tripped	SA total DPV tripped (MW)	SA % total DPV tripped	SA DPV tripped on protection only (MW)
47.8-48.8	0.64 - 1.5	591 – 887	25 – 75	133 – 381	19 – 71	10 – 87

Key findings

The historical HYTS separation (SA import) studies identified:

- For all cases, except for Cases 1 and 11, there was sufficient UFLS action to arrest the frequency nadir to above 48 Hz and maintain the RoCoF below 2 Hz/s.
- Following separation in cases 1,6 and 11 SA frequency is found to settle around 49.4 Hz and this could possibly lead to violation of the FOS if other frequency regulating measures, such as Automatic Generation Control (AGC), are not reconfigured within the required timeframe to restore frequency. AGC is normally configured to provide secondary frequency control of an intact NEM, based on a frequency measurement taken from outside SA. AGC will not act to restore frequency above 49.5 Hz within 10 minutes[46] following a separation event until it is reconfigured to correctly reflect an SA island. This reconfiguration requires the AGC in SA to use a frequency measurement from within SA, and act only to control generators located within the

[46] To return SA frequency to within the Recovery Band for an island within the mainland NEM, as required in the FOS.

island. Post separation, Frequency Regulation Reserves (Regulation FCAS) also need to be procured from within the island.

- For the studies undertaken, power system frequency in other NEM regions was maintained below 51 Hz.

5.2.2 SA import – future cases

Full NEM model

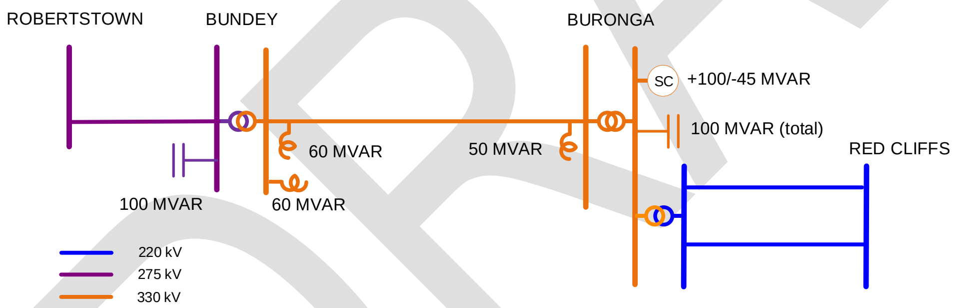
Major changes to the interconnector capacity connecting SA to the rest of the NEM will come with the commissioning of PEC, as shown in Table 12. It should be noted that the present HIC limits are 550 MW SA export and 600 MW SA import, however increased HIC transfer capacity post-PEC Stage 2 commissioning as projected by Electranet[47] is considered in the study.

Table 12 SA AC interconnector capacities, post PEC commissioning

PEC Stage	Planned date	HIC capacity (MW)	PEC capacity (MW)	Combined capacity (MW)
1	Second half 2023	600 SA Import 550 SA Export	100 SA Import 100 SA Export	700 SA Import 650 SA Export
2[47]	Second half 2024	750 SA Import 750 SA Export	800 SA Import 800 SA Export	1300 SA Import 1450 SA Export

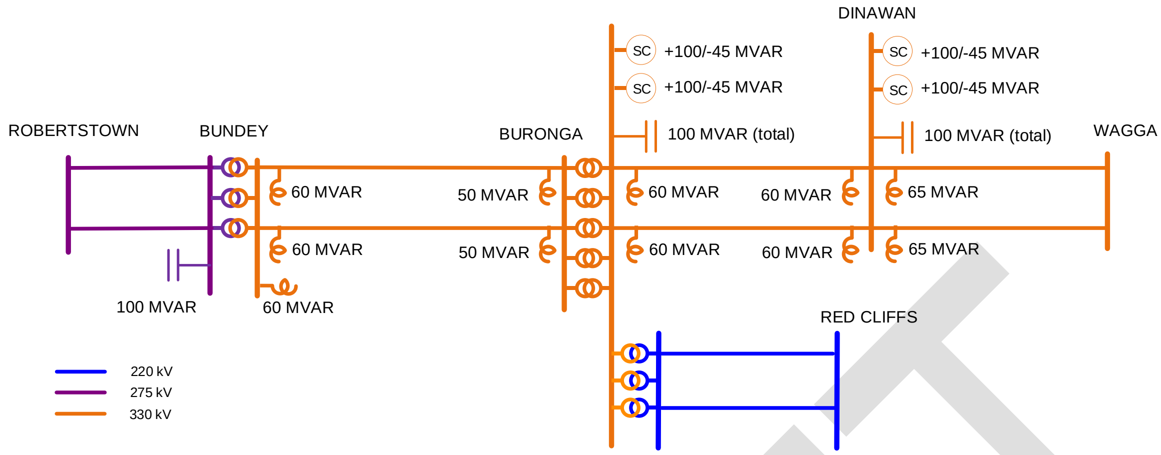
Simplified single line diagrams of PEC Stage 1 and PEC Stage 2 are shown in Figure 11 and Figure 12.

Figure 11 PEC Stage 1 single line diagram



[47] ElectraNet 2021 Transmission Annual Planning Report, p10, available at 2021-ElectraNet-Transmission-Annual-Planning-Report.pdf

Figure 12 PEC Stage 2 single line diagram



The non-credible separation of SA from HYTS was considered for import and export conditions. The full NEM model studies assume the PEC Stage 2 network configuration. ElectraNet is currently designing a special protection scheme for PEC (PEC SPS) to enable maximum transfer on PEC and HIC, while avoiding SA islanding in the event of a non-credible loss of either PEC or HIC causing transient instability on the remaining interconnector[48]. At the time of this study, specific details of the planned SPS are not available, however, the study assumes a simplified SPS action through load and SA BESS action or generation tripping.

For SA import studies the SPS action was approximated as SA load or BESS action with parameters included in Table 13. Time delay for the SPS trigger was assumed to be 250 ms. SA UFLS and OFGS were also modelled.

Table 13 PEC SPS option modelled

Plant	Load trip / battery injection (MW)
SA Load	400
SA BESS 1	60
SA BESS 2	50

Study scenarios

One study case was considered for the future studies of HYTS separation with SA importing. The case included four synchronous condensers and no synchronous generators in SA. The transfer levels of major interconnectors and power system variables are given in Table 14.

Table 14 SA separation from HYTS: system operating point for future full NEM case (SA import)

SA operational demand (MW)	SA AC import (MW)	HIC import (MW)	PEC import (MW)	MLTS transfer[49] (MW)	QLD AC import (MW)	SA inertia (MW-s)	SA DPV (MW)	SA renewables (MW)
3104	1300	648	652	1151	948	4433	371	1628

[48] As part of this process ElectraNet, Transgrid and AEMO (in its role as the Victorian transmission planner) are reviewing relevant existing emergency control schemes to determine if changes are needed due to PEC.

[49] Power flowing on MLTS-HGTS and MLTS-MRTS lines from MLTS toward SA

Table 15 SA separation from HYTS: future full NEM case results (SA import)

Region	Freq peak (Hz)	RoCoF (Hz/s)	Underlying UFLS load tripped (MW)	% underlying UFLS load tripped	Total DPV tripped (MW)	% Total DPV Tripped	DPV Tripped on protection only (MW)
SA	50.4	0.9	0	0	0	0	0

Key findings

The future HYTS separation (SA import) full NEM studies identified:

- PEC SPS action prevented instability on PEC and islanding of SA. QNI was also found to be stable during the event. In this instance, stability on QNI was maintained, however, this phenomenon should be carefully considered in the PEC SPS design process, with studies that include scenarios with QNI operating at its limits to identify whether SA separation could cause QNI instability for wider dispatch conditions.
- No load or generation was shed by SA OFGS and UFLS.

5.2.3 SA export – historical cases

Study scenarios

Twelve cases were considered for the historical studies of SA separation through the non-credible loss of the HIC during SA export conditions. Historical cases were selected for study primarily based on maximum/high HIC SA export levels (as high HIC transfers during SA separation are likely to cause the largest system frequency excursions). Coincident with historic high SA exports, SA inertia varied from 9527 to 18043 MW-s and underlying SA UFLS load ranged from 967 MW to 1777 MW. In addition, coincident with historic high SA exports, maximum DPV and SA renewable generation was 945 MW and 976 MW respectively.

The range of power system variables considered for the studies is given in Table 16. Detailed parameters of each case are included in Appendix A6.1.2.

Table 16 SA separation from HYTS: system operating points for historical cases (SA export)

SA operational demand (MW)	Total export (HIC + Murraylink) (MW)	HIC export (MW)	SA inertia (MW-s)	SA underlying UFLS load (MW)	SA OFGS available (MW)	SA DPV (MW)	SA renewables (MW)
477 - 1611	542 - 770	448 - 648	9527 - 18043	967 - 1777	357 - 723	520 - 945	575 - 976

The range of values for key power system variables observed during simulations of all considered cases are summarised in Table 17. More detailed results for each case are included in Appendix A6.1.2.

Table 17 SA separation from HYTS: historical cases results (SA export)

SA freq peak range (Hz)	SA RoCoF (Hz)	SA underlying UFLS load tripped (MW)	SA % underlying UFLS load tripped	SA OFGS tripped (MW)	SA total DPV tripped (MW)	SA % Total DPV tripped	SA DPV tripped on protection only (MW)
51 - 51.2	0.65 - 0.9	0	0	0 - 22	0	0	55 - 98

Key findings

The historical HYTS separation (SA export) studies identified:

- The frequency peak was maintained below 52 Hz for all cases studied. The frequency RoCoF was also maintained below 3 Hz/s following fault clearance.
- In most cases, OFGS operated tripping multiple OFGS wind farm (WF) plants. Large amounts of DPV tripped due to their own protection settings.
- For Case 11, QNI becomes unstable following separation of SA at HYTS. It was observed that during high export conditions, if QLD is also exporting large amounts of energy, there is a possibility of QNI losing stability following separation of SA. This leads to three islands with over-frequency in QLD and SA and under-frequency in the remaining mainland regions. Detailed graphs are included in Appendix A6.1.2.
- Frequencies in the remaining regions were maintained above 49 Hz for all HYTS separation export cases.
- For Case 7 SA frequency settled close to 51 Hz following separation at HYTS. Refer to the results for Case 7 in Appendix 6.1.2. Following OFGS action, there is a possibility that the steady-state SA frequency settles at a constant value near 51 Hz. This could lead to violation of the FOS if other frequency regulating measures, such as delayed OFGS, are not available. This is consistent with the findings of the 2020 PSFRR and AEMO is presently reviewing the SA OFGS to improve performance for over-frequency events.
- For all the historical cases considered, frequency and RoCoF were within limits. Significant relief was provided by the response of DPV due to their over-frequency trip settings, and over-frequency droop response (required by AS/NZS4777.2:2015 and AS/NZS4777.2:2020).

5.2.4 SA export – future cases

Full NEM model

An approximation of one possible option for PEC SPS design was modelled in during the export studies. It was assumed the SPS that would trip SA wind and solar generation of an amount approximately equal to the flow on HIC (approximately 740 MW in this instance). The time delay for SPS trigger was assumed to be 250 ms. SA UFLS and OFGS were also modelled.

Study scenarios

One study case was considered for the future studies of HYTS separation with SA exporting. The case models SA at close to maximum AC export (1450 MW combined over Heywood and PEC), and QLD at maximum export (1450 MW after the commissioning of the QNI minor upgrade). This represents QNI at its most susceptible to instability due to a large power swing caused by a disturbance elsewhere on the network.

SA was also modelled with no synchronous generation online, as this is a possible dispatch condition in these future scenarios. In this case the only synchronous machines online in SA are the four synchronous condensers. The power system variables of the case are given in Table 18.

Table 18 SA separation from HYTS: system operating point for future case (SA export)

SA operational demand (MW)	SA AC import (MW)	HIC import (MW)	PEC import (MW)	MLTS transfer[50] (MW)	QLD AC export (MW)	SA inertia (MW-s)	SA DPV (MW)	SA renewables (MW)
164	1445	742	702	-746	1447	4433	1980	1815

Key findings

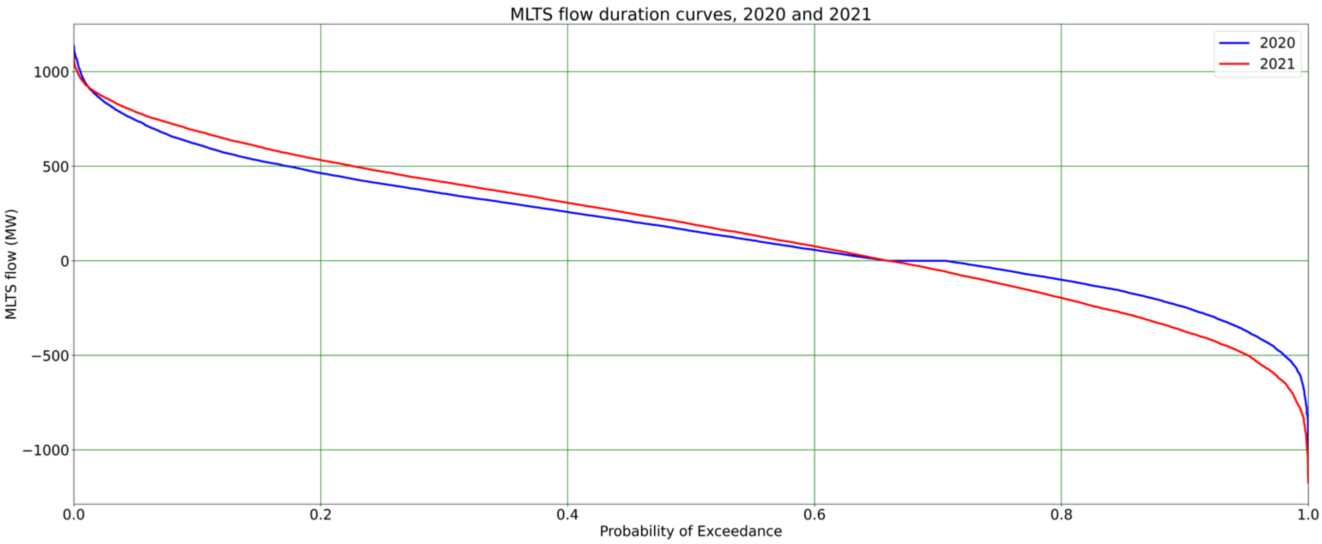
The future HYTS separation (SA export) full NEM studies identified:

- The assumed action of PEC SPS failed to maintain power system stability. Following PEC SPS action, QNI became unstable and QLD lost synchronism with the rest of the NEM, resulting in numerical instability in the simulation.
- The results show that HYTS separation and PEC SPS action can possibly cause loss of stability on QNI. This phenomenon should be carefully considered in the PEC SPS design process.

5.3 Contingency 2 – SA separation from MLTS

The non-credible separation of SA from MLTS was considered for import and export conditions. Figure 13 shows the probability of exceedance (PoE) for the power flow from SA to MLTS and MLTS to SA from 1 January 2020 to 31 December 2021.

Figure 13 Duration curves for the MLTS towards SA power flow from for 2020 and 2021



Note: positive interconnector flow indicates flow direction from MLTS to the West.

[50] Power flowing on MLTS-HGTS and MLTS-MRTS lines from MLTS toward South Australia

5.3.1 SA import – historical cases

Study scenarios

Ten cases were considered for the historical studies of the non-credible SA separation from MLTS during SA import conditions. Historical cases were selected for study primarily based on maximum/high SA import levels (as high SA import transfers during SA separation are likely to cause the largest system frequency excursions). Coincident with historic high SA imports, SA inertia varied from 9805 to 21038 MW-s and underlying SA UFLS load ranged from 651 MW to 2448 MW. In addition, coincident with historic high SA exports, maximum DPV and SA renewable generation was 648 MW and 365 MW respectively. The range of power system variables considered for the studies are given in Table 19. Detailed parameters of each case are included in Appendix A6.2.1.

Table 19 SA separation from MLTS: power system operating points for historical cases (SA import)

SA operational demand (MW)	Total import (HIC + Murraylink) (MW)	HIC import (MW)	SA Inertia (MW-s)	SA underlying UFLS load (MW)	SA DPV (MW)	SA renewables (MW)
1028 - 2476	529 - 858	437 - 678	9805 - 21038	651 - 2448	0 - 648	0 - 365

The range of values for key power system variables observed during simulations of all considered cases are summarised in Table 20. More detailed results for each case are included in Appendix A6.2.1.

Table 20 SA separation from MLTS: historical cases results (SA import)

SA freq nadir range (Hz)	SA RoCoF (Hz)	SA underlying UFLS load tripped (MW)	SA % underlying UFLS load tripped	SA total DPV tripped (MW)	SA % total DPV tripped	SA total DPV tripped on protection only (MW)
47.8 – 49.7	0.2 - 1.71	0 – 887	0 – 75	0 – 381	0 – 71	0 – 56

Key findings

The historical MLTS separation (SA import) studies identified:

- The frequency nadir was maintained above 48 Hz except for Case 1, where it fell to 47.8 Hz. The frequency in the rest of the NEM was maintained below 51 Hz for all cases.
- The frequency RoCoF was below 2 Hz/s following fault clearance.
- For most of the cases, the EAPT scheme separated SA at HYTS following MLTS separation based on topology-only criteria. Details of EAPT operation in regard to individual cases is included in Appendix A6.2.1.
- For MLTS import Case 1, SIPS Stage 3 operated at 2.07 s and tripped HIC. For this case SA frequency was found to settle at 49 Hz after the event. This could lead to the violation of FOS if other frequency regulating measures such as delayed UFLS are not available. AEMO will continue to monitor this in future GPSRRs.
- The results indicate that there was sufficient UFLS present in SA to maintain frequency at or above 48 Hz for all MLTS separation import cases except Case 1 where the SA frequency nadir was 47.8 Hz and 75% of the available UFLS was tripped.

5.3.2 SA import – future cases

Full NEM model

Study scenarios

The simplified PEC SPS assumption described in Section 5.2.2 were applied for import studies. One study case was considered for the future studies of MLTS separation with SA importing. The case models SA at maximum AC import, and QLD also at maximum import (950 MW after the commissioning of the QNI minor upgrade). This represents QNI at its most susceptible to instability due to a large power swing caused by a disturbance elsewhere on the network. Additionally, SA was modelled with no synchronous generation online, as this is a possible dispatch condition in future scenarios. The only synchronous machines online in SA are the four synchronous condensers. The power system variables of the case are given in Table 21.

Table 21 SA separation from MLTS: system operating point for future case (import)

SA operational demand (MW)	SA AC import (MW)	HIC import (MW)	PEC import (MW)	MLTS transfer[51] (MW)	QLD AC import (MW)	SA inertia (MW-s)	SA DPV (MW)	SA renewables (MW)
3104	1300	648	652	1151	948	4433	371	1628

Table 22 SA separation from MLTS: future full NEM case results (import)

Region	Freq peak (Hz)	RoCoF (Hz/s)	Underlying UFLS load tripped (MW)	% Underlying UFLS load tripped	Total DPV tripped (MW)	% Total DPV tripped	DPV tripped on protection only (MW)
SA	50.5	1.1	0	0	0	0	0

Key findings

The future SA separation from MLTS (SA import) full NEM studies identified:

- During the contingency, the action of PEC SPS prevented instability on PEC and SA islanding. The results confirm that, in principle, a PEC SPS that trips load and injects power from batteries can avoid a trip of PEC following separation at MLTS under the studied conditions
- No load or generation was shed by SA OFGS or UFLS.
- The results conclude that MLTS separation and consequent PEC SPS action can cause large power swings on QNI. However wider system conditions need to be analysed with final SPS design to confirm QNI stability.

5.3.3 SA export – historical cases

Study scenarios

Eleven cases were considered for the historical studies of the non-credible SA separation from MLTS during SA export conditions. Historical cases were selected for study primarily based on maximum/high SA export levels (as high SA export transfers during SA separation are likely to cause the largest system frequency excursions). Coincident with historic high SA exports, SA inertia varied from 13134 to 22985 MW-s and underlying SA UFLS

[51] Power flowing on MLTS-HGTS and MLTS-MRTS lines from MLTS toward SA

load ranged from 938 MW to 1897 MW. In addition, coincident with historic high SA exports, maximum DPV and SA renewable generation was 778 MW and 1011 MW respectively. The range of power system variables considered for the studies are given in Table 23. Detailed parameters of each case are included in Appendix A6.2.2.

Table 23 SA separation from MLTS: system operating points for historical cases (SA export)

SA operational demand (MW)	Total export (HIC + Murraylink) (MW)	HIC export (MW)	SA inertia (MW-s)	SA underlying UFLS load (MW)	SA available OFGS (MW)	SA DPV (MW)	SA renewables (MW)
777 - 1989	503 - 644	501 - 560	13134 - 22985	938 - 1897	21-778	0 - 900	210 - 1011

The range of values for key power system variables observed during simulations are summarised in Table 24. More detailed results for each case are included in Appendix A6.2.2.

Table 24 SA separation from MLTS: historical case results (SA export)

SA freq peak range (Hz)	SA RoCoF (Hz)	SA underlying UFLS load tripped (MW)	SA % underlying UFLS load tripped	SA OFGS tripped (MW)	SA total DPV tripped (MW)	SA % Total DPV tripped	SA DPV tripped on protection only (MW)
50.2 – 51.8	0.08 - 1.11	0	0	0 - 32	0	0	50.2 – 51.8

Key findings

The historical MLTS separation (SA export) studies identified:

- The frequency peak was maintained below 52 Hz and RoCoF was maintained below 3 Hz/s following fault clearance for all cases studied.
- Frequencies in the rest of the NEM were maintained above 49 Hz for all MLTS Export cases.
- For many MLTS Export cases, OFGS operated.
- For Case 1 and Case 3, QNI becomes unstable following separation of SA at MLTS. Detailed graphs are included in Appendix 6.2.2. When there is an export into VIC at MLTS and QLD is exporting, following the SA separation at MLTS, there is a possibility that QNI can become unstable and this leads to NEM split into three islands. Detailed graphs are included in Appendix 6.2.2.

5.3.4 SA export – future cases

Full NEM model

An approximation of one possible option for PEC SPS design was modelled in the export studies. It was assumed the PEC SPS would trip SA wind and solar generation of an amount approximately equal to the power that would otherwise be forced onto PEC due to SA separation from MLTS (approximately 800 MW in this instance).

Other emergency control schemes that could also be triggered by the contingency were modelled:

- SA UFLS and OFGS.
- South West Special Control Scheme (SW500SCS).

- APD potline trip[52].

Study scenarios

One study case was considered for the future studies of MLTS separation with SA exporting. The power system variables of the case are given in Table 25. The interconnectors were loaded close to their limits and with no synchronous machines online in SA except for the four synchronous condensers.

Table 25 SA separation from MLTS: system operating points for future cases (export)

SA operational demand (MW)	SA AC export (MW)	HIC export (MW)	PEC export (MW)	MLTS transfer (MW) [53]	QLD AC export (MW)	SA inertia (MW-s)	SA DPV (MW)	SA renewables (MW)
164	1445	742	702	-746	1447	4433	1980	1815

Key findings

The future MLTS separation (SA export) full NEM studies identified that QNI, PEC and VNI all become unstable even before PEC SPS operation is completed. MLTS separation can lead to instability on other interconnectors, including QNI, despite SPS action to balance power flows. The studied case had relatively low output from gas and wind generation between HYTS and MLTS (551 MW of wind generation was dispatched out of total 1431 MW of existing or committed wind and 582 MW existing gas generation). This issue will be further exacerbated if there is higher generation between MLTS and HYTS. The separation would cause a greater power swing on PEC and QNI making it more challenging for SPS to maintain stability. This phenomenon should be carefully considered during the PEC SPS design process.

5.4 Contingency 3 – QLD separation through QNI loss

Non-credible loss of QNI was considered for historical scenarios during both QLD import and export conditions. The QNI flow from 1 January 2020 to 31 December 2021 is shown in Figure 14, which indicates that QNI flow could be above 1200 MW QLD export for 0.07% duration (12 hours) and above 600 MW QLD import for 0.2% duration (35 hours). QNI flow (vs) SA DPV generation for calendar year 2021 is included in Figure 15. It may be noted that QLD DPV generation considered in historical study cases snap shots for the period 1/1/2019 to 1/7/2020 was lower in comparison with the 2021 DPV generation reflecting the DPV growth.

[52] This is not an emergency control scheme, it is reflecting the fact that both APD potlines could trip in response to the voltage disturbance caused by the faults on the 500 kV lines. Trip of MLTS-HGTS or MLTS-MOPS and subsequent loss of two APD potlines are credible contingencies.

[53] Power flowing on MLTS-HGTS and MLTS-MRTS lines from MLTS toward SA

Figure 14 Duration curves for the QNI power flow for 2020 and - 2021

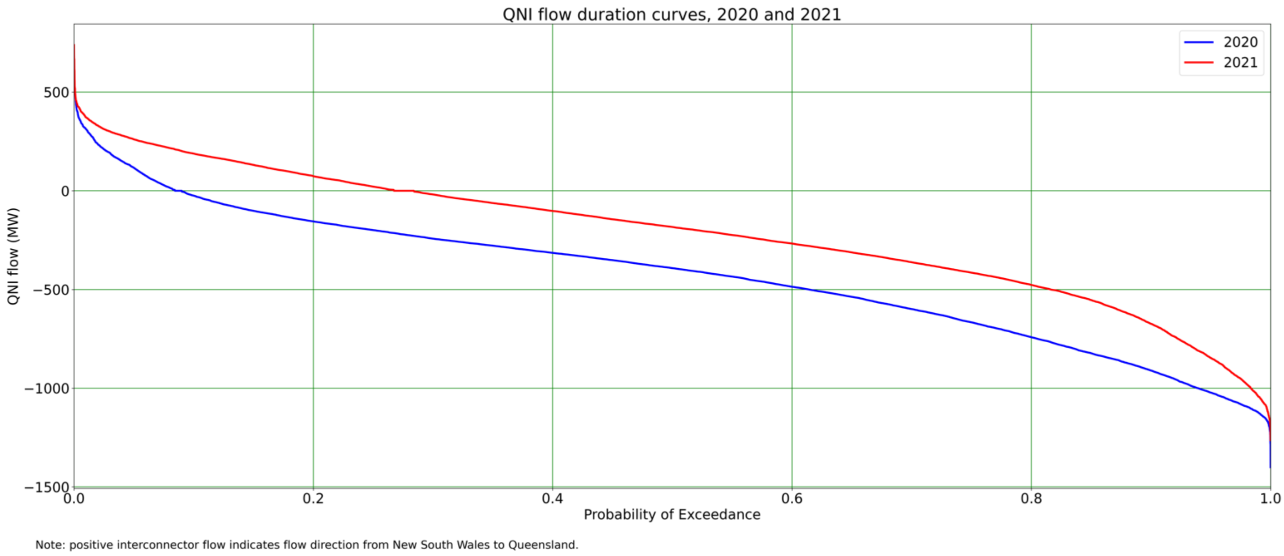
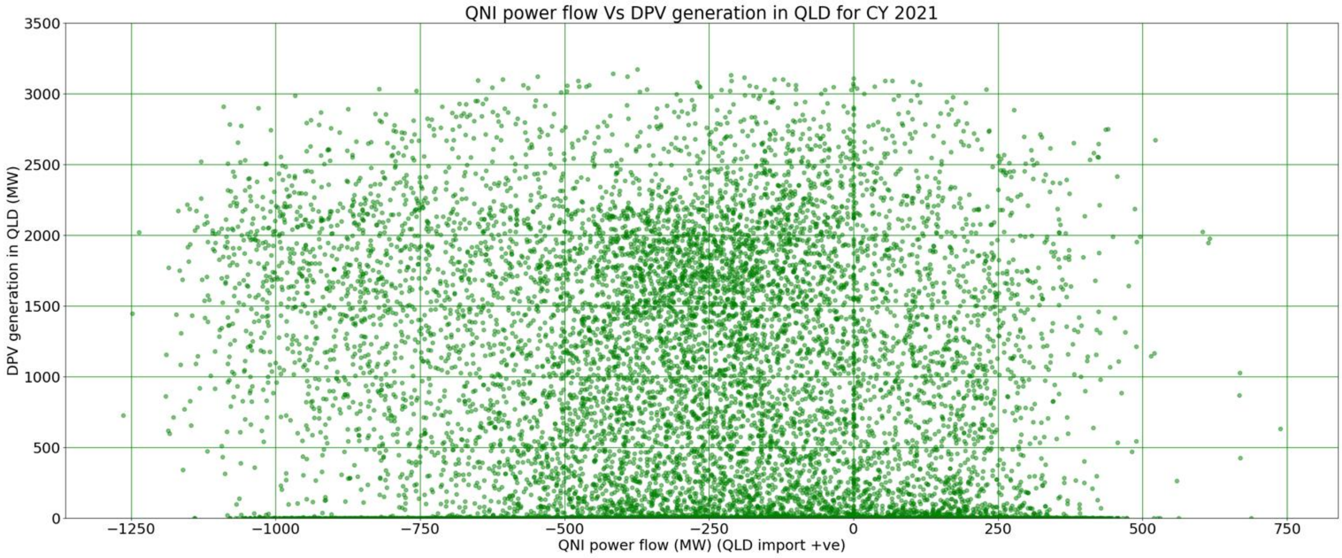


Figure 15 QNI flow (vs) QLD DPV generation in CY 2021



5.4.1 QLD import – historical cases

Study scenarios

Eight cases were considered for the historical studies of the non-credible loss of QNI during QLD import conditions. Historical cases were selected for study primarily based on maximum/high QLD import levels (as high QLD imports during QNI loss are likely to cause the largest system frequency excursions). Coincident with historic high QLD imports, QLD inertia varied from 25912 to 34126 MW-s and underlying QLD UFLS load ranged from 3143 to 5713 MW. In addition, coincident with historic high QLD exports, maximum DPV and QLD renewable generation was 2815 MW and 1075 MW respectively. The range of power system variables considered for the studies are given in Table 26 and the details of each case are given in Appendix A6.3.1.

Table 26 System operating points for historical cases (QNI Import)

Region	Operational demand (MW)	Pgen (MW)	QNI import (MW)	Inertia (MW-s)	Underlying UFLS load (MW)	Total DPV (MW)	Renewables (MW)
QLD	5761 - 10532	5398 - 10308	115 - 535	25912 – 34126	3143 - 5713	0 - 2815	99 - 1075
Remaining NEM	14082 - 18923	15030 - 19770	-	63637 - 73820	8348 - 11280	0 - 3986	1438 - 3361

The maximum values of key power system variables observed during simulations of all the considered cases are summarised in Table 27 and detailed results for each case are included in Appendix A6.3.1.

Table 27 Simulation results for historical cases (QNI Import)

Region	Frequency peak/nadir range (Hz)	Max RoCoF range (Hz)	Max UFLS tripped (MW)	Max % underlying UFLS load tripped	Max DPV tripped (MW)	Max % DPV tripped
QLD	48.94 – 49.53	0.14 - 0.44	688	15.49	362	16.86
Remaining NEM	50.05 – 50.18	0.03 - 0.16	0	0	3.58	0.1
TAS	50.05 - 50.13	0.01 - 0.15	-	-	-	-

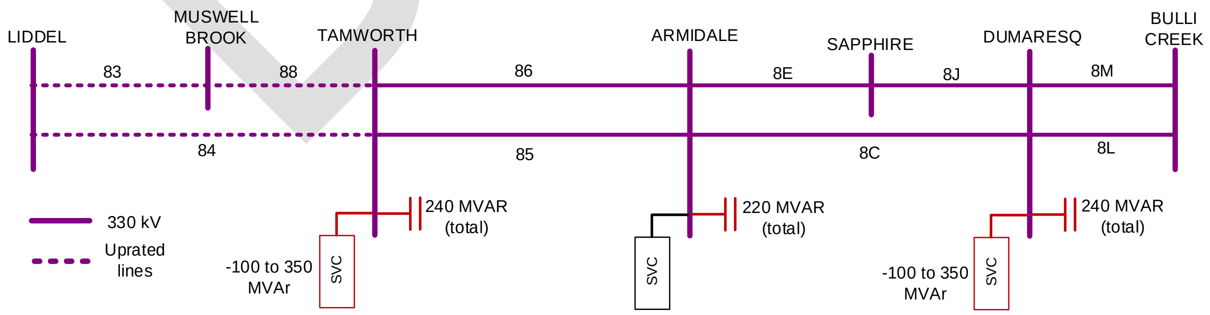
Key findings

For most of the studied cases, QLD frequency nadir could reach just below 49 Hz after the loss of QNI, resulting in UFLS actions in QLD and QLD frequency was restored successfully. The frequency in the rest of the NEM was regulated below 50.18 Hz.

5.4.2 QLD import – future cases (simplified NEM model)

Non-credible loss of QNI was considered for future scenarios with QLD import and export conditions. QNI upgrades are currently being commissioned by Transgrid and Powerlink to increase QNI transfer levels to 1450 MW in the southerly direction and 950 MW in the northerly direction. The additional compensation devices between Tamworth and Bulli Creek substations that will be available following the QNI upgrade are shown in the simplified network diagram in Figure 16. The simulation studies included the compensating devices and the associated dynamic models in the study. The studies were carried out using a simplified NEM model.

Figure 16 QNI upgrade details



Study scenarios

A total of 18 cases were considered for non credible QNI loss future studies while QLD is importing. For all regions except SA, three different generator dispatch scenarios (Scenario 1, Scenario 2, and Scenario 3), which are described in Section 5.1.2, were considered. For SA, four synchronous condensers with 0 synchronous generating unit online were assumed. The range of power system variables considered for the studies are given in Table 28 and the details of each case are given in Appendix A6.14.1.

Table 28 System variables range for future cases (QNI Separation: QNI import)

Region	Operational demand (MW)	Pgen (MW)	QNI Import (MW)	Inertia (MW-s)	Operational UFLS (MW)	Net DPV (MW)
QLD	2388-9370	4012-9949	950	10877-14861	1774-5002	0-6346
Remaining NEM	5999-13821	13835-19836	-	19166-28473	2869-9108	0-12660

The range of values for key power system variables observed during the simulations are summarised in Table 29, Table 30 and Table 31. More detailed results for each case are included in Appendix A6.14.1.

Table 29 Simulation results of future cases for generation dispatch Scenario 1

Region	Frequency peak/nadir range (Hz)	Max RoCoF range (Hz)	Max UFLS tripped (MW)	Max % underlying UFLS tripped	Total DPV tripped (MW)	Total DPV tripped (%)
QLD	48.63-48.85	0.7-1.05	1160-3084	27-60.1	0-6345	0-100
Remaining NEM	50.53-50.9	0.38-0.62	0	0	0-535	0-43

Table 30 Simulation results of future cases for generation dispatch Scenario 2

Region	Frequency peak/nadir range (Hz)	Max RoCoF range (Hz)	Max underlying UFLS load tripped (MW)	Max % underling UFLS load tripped	Total DPV tripped (MW)	Total DPV tripped (%)
QLD	48.62-48.84	0.8-1.25	1258-3084	27-60.1	0-6345	0-100
Remaining NEM	50.5-50.88	0.38-0.63	0	0	0-535	0-4.3

Table 31 Simulation results of future cases for generation dispatch Scenario 3

Region	Frequency peak/nadir range (Hz)	Max RoCoF range (Hz)	Max underlying UFLS load tripped (MW)	Max % underlying UFLS load tripped	Total DPV tripped (MW)	Total DPV tripped (%)
QLD	48.6-48.8	0.92-1.45	1272-3084	22-60.1	0-6345	0-100
Remaining NEM	50.54-50.88	0.36-0.75	0	0	0-535	0-4.3

Key findings

The future non credible QNI loss (QNI import) simplified studies identified:

- In most of cases, QLD UFLS availability was sufficient to maintain QLD frequency above 48.5 Hz and the frequency in the rest of the NEM was regulated below 51 Hz. Except for Case 6, where QLD frequency collapsed following QNI separation due to ineffective UFLS caused by large amount of underlying DPV trips (refer Appendix A6.16.1). This shows that when there is ineffective UFLS, frequency collapse could occur in QLD following separation.

- Case 5 has the lowest frequency nadir 48.63 Hz (Scenario 1), see Appendix A6.16.1.

5.4.3 QLD export – historical case

Study scenarios

Seven cases were considered for the historical studies of the non-credible loss of QNI during QLD export conditions. Historical cases were selected for study primarily based on maximum/high QLD export levels (as high QLD exports during QNI loss are likely to cause the largest system frequency excursions). Coincident with historic high QLD exports, QLD inertia varied from 23254 to 41427 MW-s and underlying QLD UFLS load ranged from 3299 to 4202 MW. In addition, coincident with historic high QLD exports, maximum DPV and QLD renewable generation was 1796 MW and 954 MW respectively. The range of power system variables considered for the studies are given in Table 32 and the details of each case are given in Appendix A6.3.2.

Table 32 System variables range for historical cases (QNI loss: QLD exporting)

Region	Operational demand (MW)	Pgen (MW)	QNI export (MW)	Inertia (MW-s)	Underlying UFLS load (MW)	Total DPV (MW)	Renewables (MW)
QLD	5799 - 7929	7266 - 9508	1164 - 1374	23254 - 41427	3299 - 4202	0 - 1796	126 - 954
Remaining NEM	14148 - 21474	13499 - 20872	-	55070 - 100033	8481 - 13202	0 - 2808	416 - 3329

The maximum values of key power system variables observed during simulations are summarised in Table 33 and detailed results for individual cases are included in Appendix A6.3.2.

Table 33 Simulation results for historical cases (QNI Export)

Region	Frequency Peak/Nadir range (Hz)	Max RoCoF range (Hz)	Max UFLS tripped (MW)	Max % underlying UFLS load tripped	Max total DPV tripped (MW)	Max % DPV tripped
QLD	51 - 52.5	0.23 - 0.39	0	0	368	25.7
Remaining NEM	48.95 – 49.1	0.19 - 0.39	1396	14.4	245	12.41
TAS	47.66 – 48.95	0.33 - 1.09	178	-	-	-

Key findings

The historical non credible QNI loss (QLD export) studies identified:

- Following QNI loss QLD frequency exceeded 52 Hz when QLD generation was predominantly from synchronous generating units. When QLD frequency reaches around 52.5 Hz, studies showed that some synchronous generating units trip on their over-frequency settings and regulate frequency back below 52 Hz (refer Case 1 in Appendix A6.3.2).
- Frequency in Queensland could rise above 52 Hz following the loss of QNI.
- Frequency in the rest of the NEM dipped below 49 Hz, however, it then regulated above 49 Hz following the UFLS action.
- For some cases, EAPT operated, resulting in SA separation from Heywood. EAPT operation would not be expected once a topology-based scheme is implemented.

5.4.4 QLD export – future cases (simplified NEM model)

Study scenarios

Five cases were considered for non credible QNI loss future studies while QLD is exporting. For all regions except SA, three different generator dispatch scenarios (Scenario 1, Scenario 2, and Scenario 3), which are described in Section 5.1.2, were considered. For SA, four synchronous condensers with 0 synchronous generating units online was assumed. The range of power system variables considered for the studies are given in Table 34 and the details of each case are given in Appendix A6.14.2.

Table 34 System variables range for future cases (QNI loss: QLD exporting)

Region	Operational load (MW)	Pgen (MW)	QNI export (MW)	Inertia (MW-s)	UFLS (MW)	DPV (MW)
QLD	1865-4646	7211-9632	1450	10877-14861	1363-2661	2232-6345
Remaining NEM	5061-9260	11283-16192	-	14701-24007	1946-5627	6203-12780

The range of key power system variables observed during the simulations are summarised in Table 35, Table 36 and Table 37. Detailed results of each case are included in Appendix A6.14.2.

Table 35 Simulation results of the future cases for generation dispatch Scenario 1 (QNI loss: QLD exporting)

Region	Frequency peak/nadir range (Hz)	Max RoCoF range (Hz)	Underlying UFLS load tripped (MW)	% Underlying UFLS load tripped	Total DPV tripped (MW)	% DPV tripped
QLD	51.03-51.59	1.20-1.63	0	0	205-502	7-9
Remaining NEM	48.92-48.72	0.69-0.92	2103-3988	26-48	1688-5765	24-45

Table 36 Simulation results of the future cases for generation dispatch Scenario 2 (QNI loss: QLD exporting)

Region	Frequency peak/nadir range (Hz)	Max RoCoF range (Hz)	Underlying UFLS load tripped (MW)	% Underlying UFLS load tripped	Total DPV tripped (MW)	% DPV tripped
QLD	51.05-51.72	1.28-1.74	0	0	200-541	7-9
Remaining NEM	48.91-48.71	0.74-1.02	2370-5326	21-58	1617-6025	22-47

Table 37 Simulation results of the future cases for generation dispatch Scenario 3 (QNI loss: QLD exporting)

Region	Frequency Peak/Nadir range (Hz)	Max RoCoF range (Hz)	Underlying UFLS load tripped (MW)	% Underlying UFLS load tripped	Total DPV tripped (MW)	% DPV Tripped
QLD	51.08-51.82	2.12-2.54	0	0	200-940	8-15
Remaining NEM	47.9-48.55	0.95-1.23	3400-5423	33-59	1875-4498	23-42

Key findings

- For the QLD export cases, maximum over-frequency was seen to be less than 52 Hz for all cases. Whilst historic studies showed potential over-frequency of more than 52 Hz, this is due to FCAS limits applied to synchronous generating units according to their PFR capabilities in the historic studies. Future studies use lumped generator models assuming minimum PFR droop gains without specific limits for IBRs and the generator's maximum FCAS raise is limited to +5 % of Pmax and lower limited to -10 % of Pmax and, hence, these results are more optimistic.

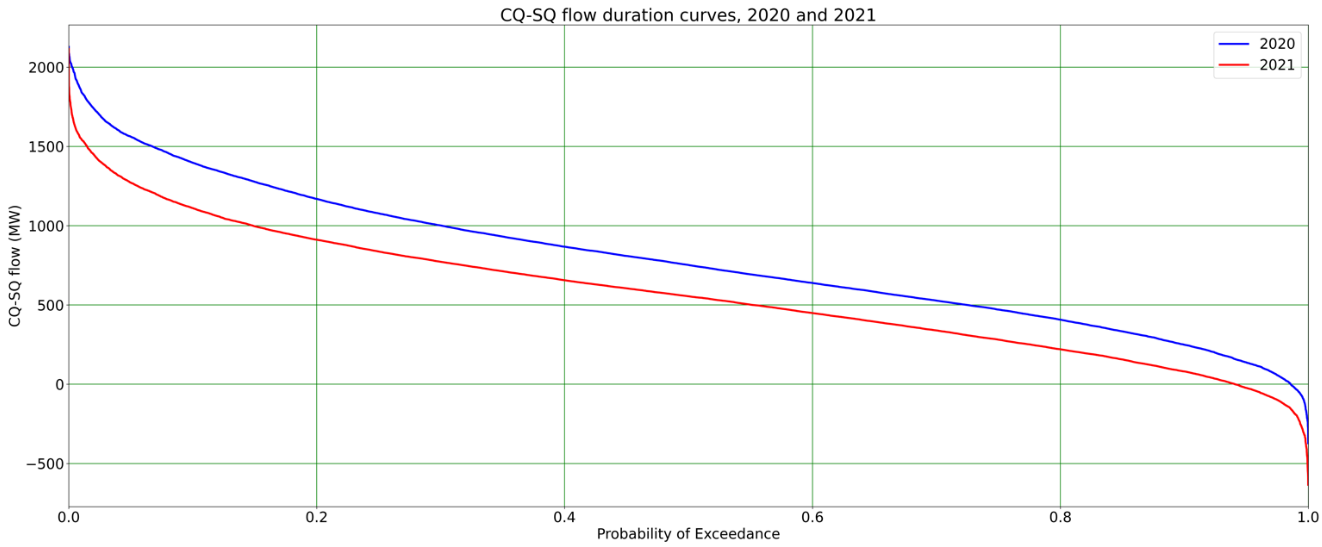
- The frequency in the rest of the NEM dipped below 49 Hz resulting in UFLS action that was sufficient to arrest the frequency nadir above 48 Hz in all cases except Case 3.
- A high RoCoF around 2.54 Hz/sec is observed in QLD. This high RoCoF could impact the fault ride through capabilities of synchronous generators.
- As inertia is reduced from Scenario 1 to Scenario 3, the maximum RoCoF in the rest of the NEM is increased from 0.92–1.23 Hz/s following QNI separation.

5.5 Contingency 4 – loss of both 275 kV lines between Calvale – Halys

The non-credible loss of both 275 kV lines between Calvale – Halys in QLD was considered for QNI import and QNI export conditions. During high northern and central QLD generation dispatch CQ-SQ cut-set flow can reach around 2000 MW. Based on historic data this occurs 0.15% of the time (or 26 hours per year). Figure 17 shows the PoE for the CQ-SQ cut-set power flow from north to south QLD from 1 January 2020 to 31 December 2021.

An SPS, known as Wide Area Monitoring Protection And Control (WAMPAC), has been implemented in QLD to trip necessary generation and load to preserve the stability and overloading of the CQ-SQ eastern corridor 275 kV and QNI lines following the loss of the Calvale – Halys lines. The implementation of WAMPAC was intended to significantly reduce the risks associated with loss of Calvale – Halys 275 kV circuits, but not intended to cover all possible power transfer conditions across CQ-SQ and QNI.

Figure 17 Duration curve for the CQ-SQ cut-set power flow for 2020 and - 2021



Note: positive interconnector flow indicates flow direction from North to South.

5.5.1 QLD import – historical cases

Study scenarios

Six cases were considered for the historical studies of the non-credible loss of both Calvale – Halys 275 kV lines during QLD import conditions. Historical cases were selected for study primarily based on maximum/high CQ-SQ flows (as high CQ-SQ flow during this contingency are likely to cause onerous conditions). Coincident with historic high CQ-SQ flow, Calvale – Halys flow varied from 519 MW to 884 MW and QLD imports varied from 156 MW to 557 MW. In addition, coincident with historic high CQ-SQ flow, maximum WAMPAC load and generation trip availability was 405 MW and 1204 MW respectively. To confirm the WAMPAC generation and load-arming logic, as provided by Powerlink, was implemented in the modelling.

The range of power system variables considered for the studies and the amount of generation and load available to and actually tripped by WAMPAC during contingency are given in Table 38. Detailed parameters of each case are included in the in Appendix A6.4.1.

Table 38 Calvale – Halys separation: system operating points for historical cases (QLD import)

QNI Import (MW)	Calvale – Halys Flow (MW)	Eastern corridors (MW)	CQSQ Flow (MW)	Load available for tripping (MW)	Generation available for tripping (MW)
156 - 557	519 - 884	741 - 1151	1260 - 2035	172 - 405	1046 - 1204

A high-level summary of the study results is given in Table 39. The detailed results of individual study cases are included in Appendix A6.4.1.

Table 39 Calvale – Halys trip: historical cases results (QLD import)

Predicted Gen to Trip (MW)	Predicted Load to trip (MW)	Actual Gen Tripped (MW)	Actual Load tripped (MW)	DPV tripped in QLD on protection only (MW)
213 - 1247	0 - 300	399 - 1110	0 - 184	32 - 135

Key findings

The historical non credible loss of Calvale - Halys (QNI import) studies identified:

- For all the contingency cases considered, the CQ-SQ eastern corridor 275 kV and QNI lines maintain stability of the CQ-SQ eastern corridor 275 kV and QNI lines following the non-credible contingency.
- The operation of WAMPAC was sufficient to maintain stability of the CQ-SQ eastern corridor 275 kV and QNI lines following the contingency. For two low load cases, however, not all the generation predicted by the linearised WAMPAC logic could be tripped to stay within the net 970 MW ceiling. Notwithstanding this, the cases were still stable due to the conservative nature of the WAMPAC settings. Powerlink is monitoring the situation and will address any shortfall identified.

5.5.2 QLD import – future cases (full NEM model)

The non-credible trip of both 275 kV lines between Calvale – Halys in QLD was considered for 2027 future scenario studies using a full NEM model. QNI upgrades are currently being commissioned by Transgrid, which are aimed to increase southerly QNI transfer levels to 1,450 MW and 950 MW in the northerly direction. The QNI upgraded network, models and transfer limits were considered in the contingency study cases.

Based on historical data, during high northern and central QLD generation dispatch, the CQ-SQ cut-set flow can reach around 2,100 MW when QLD is exporting and as high as 1,900 MW when QLD is importing. There are no committed projects to increase the CQ-SQ power transfer capability by 2027.

To be conservative, the future studies considered very high CQ-SQ cut-set flows coincident with flows on QNI approaching the limit with the interconnector upgrade project commissioned. The studies also included the present WAMPAC scheme.

Study scenarios

Six future scenarios were considered to study the non-credible trip of both Calvale – Halys 275 kV lines when QLD is importing. In four cases, the QNI northerly flow was dispatched at above 900 MW, which corresponds to approximately the predicted maximum flow limits. The range of power system variables considered for the studies and the generation and load WAMPAC settings, the actual amount of generation and load available in the case for tripping are given in Table 40. Detailed parameters of each case are included in Appendix A6.13.1.

Table 40 Calvale – Halys trip: system operating points for future cases (QLD import)

QNI Import (MW)	Calvale – Halys Flow (MW)	Eastern corridors (MW)	CQSQ Flow (MW)	Load available for WAMPAC tripping (MW)	Gen available for WAMPAC tripping (MW)
482 - 930	482-752	1111 - 1280	1594 - 1927	172 - 405	1392 - 1970

A high-level summary of the study results is given in Table 41. The detailed results of each case are included in Appendix A 6.13.1.

Table 41 Calvale – Halys separation: future cases results (QLD import)

WAMPAC Predicted Gen to Trip (MW)	WAMPAC Predicted Load to trip (MW)	Actual Gen Tripped by WAMPAC (MW)	Actual Load tripped by WAMPAC (MW)	Number of unstable cases
682 - 1247	0 - 281	800 - 1353	0 - 408	5

Key findings

The future non credible loss of Calvale - Halys (QLD import) full NEM studies identified:

- Most cases with CQ-SQ transfer and QNI import set close to their respective limits were found to lose stability.
- The studies indicate that, when Queensland imports above 600 MW coincide with high Central Queensland-Southern Queensland (CQ-SQ) transfers, the WAMPAC scheme will not be able to ensure QNI and CQ-SQ cut-set line stabilities.
- If QNI swing could be maintained within its stability limit, it will be possible to maintain the stability of the eastern corridors through WAMPAC action.
- Historical data indicates that, normally, when QLD is importing more than 550 MW, the CQ-SQ southerly flow was below 1,500 MW. In future, following the QNI upgrade, if fewer QLD southern synchronous generating units were in operation due to various reasons, higher QLD import and higher CQ-SQ flows are expected. To meet these circumstances, WAMPAC will need to be reviewed and improvements made to maintain stability of QNI and the CQ-SQ eastern corridor lines.

5.5.3 QLD export – historical cases

Study scenarios

Eight cases were considered for the historical studies of the non-credible loss of both Calvale – Halys 275 kV lines during QLD export conditions. Historical cases were selected for study primarily based on maximum/high CQ-SQ flows (as high CQ-SQ flow during this contingency are likely to cause the largest system frequency excursions). Coincident with historic high CQ-SQ flow, Calvale – Halys flow varied from 636 MW to 1064 MW and QLD exports varied from 587 MW to 1219 MW. In addition, coincident with historic high CQ-SQ flow, maximum WAMPAC load and generation trip availability was 416 MW and 1224 MW respectively. To confirm the WAMPAC generation and load-arming logic, as provided by Powerlink, was implemented in the modelling. The range of power system variables considered for the studies and the amount of generation and load available to and actually tripped by WAMPAC during contingency are given in Table 42. Detailed parameters of each case are included in Appendix A6.4.2.

Table 42 Calvale – Halys trip: system operating points for historical cases (QLD export)

QNI export (MW)	Calvale – Halys Flow (MW)	Eastern corridors (MW)	CQSQ Flow (MW)	Load available for tripping (MW)	Gen available for tripping (MW)
587 - 1219	636 - 1064	548 - 1118	1212 - 2089	80 - 416	872 - 1224

The maximum values of key power system variables observed during the simulations are summarised in Table 43 and more detailed results for each case are included in Appendix A6.4.2.

Table 43 Calvale – Halys trip: historical cases results (QLD export)

Predicted Gen to Trip (MW)	Predicted Load to trip (MW)	Actual Gen Tripped (MW)	Actual Load tripped (MW)	DPV tripped in QLD on protection only (MW)
149-1318	0-377	401-1224	0-416	0 - 171

Key findings

The historical non credible loss of Calvale - Halys (QLD export) studies identified:

- For all the contingency cases considered, the CQ-SQ eastern corridor 275 kV and QNI lines maintained stability following the contingency.
- Similar to the historical import studies, the operation WAMPAC was found to be sufficient to maintain stability of the CQ-SQ eastern corridor 275 kV and QNI lines following the contingency. In some of the cases, there were deficiencies between the amount of generation and load required by WAMPAC to trip and the actual load and generation available for arming. Even though the cases with the deficiency did not show any instabilities due to the margins of the WAMPAC scheme, Powerlink is monitoring the situation and will address any shortfall identified.

5.5.4 QNI export – future cases (full NEM model)

Study scenarios

Six historical cases were considered to study the non-credible separation of Calvale – Halys 275 kV lines when QLD is exporting. The range of power system variables considered for the studies and the amount of generation and load as predicted by WAMPAC as required, the actual range of generation and load available in the cases for tripping along with the amount of generation and load tripped during contingency and simulation outcome are given in Table 44. Detailed parameters of each case are included in Appendix A6.13.2.

Table 44 Calvale – Halys trip: system operating points for future cases (QNI export)

QNI export (MW)	Calvale – Halys Flow (MW)	Eastern corridors (MW)	CQSQ Flow (MW)	Load available for tripping (MW)	Gen available for tripping (MW)
1318 - 1450	629 - 749	1286 - 1397	1965 - 2094	157 - 406	1275 - 1851

A high-level summary of the study results is given in Table 45 and more detailed results for individual cases are included in Appendix A6.13.2.

Table 45 Calvale – Halys trip: future cases results (QNI export)

WAMPAC predicted Gen to Trip (MW)	WAMPAC predicted Load to trip (MW)	Actual Generation Tripped by WAMPAC (MW)	Actual Load tripped by WAMPAC (MW)	Number of unstable cases
1200 - 1382	234 - 415	1036 - 1275	157 - 371	0

Key findings

The future Calve - Halys separation (QNI export) full NEM studies identified:

- The transient stability and credible contingency checks completed indicated that it would be challenging to manage transient stability of QNI following the trip of one of the QNI lines at export levels above 1,400 MW.
- For the cases considered, the stability of the 275 kV eastern corridors of CQ-SQ and QNI were preserved when QLD was exporting with increased QNI transfers following the upgrade provided by WAMPAC.
- For some low load cases, not all the generation predicted by the linearised WAMPAC logic could be tripped to stay within the net 970 MW ceiling. Notwithstanding this, the cases were still stable due to the conservative nature of the WAMPAC settings. Powerlink is monitoring the situation and will address any shortfall identified.

5.6 Contingency 7 – loss of both Dederang to South Morang 330 kV lines

The non-credible loss of both Dederang to South Morang 330 kV lines was considered. During this contingency, the IECS SPS will operate if the IECS is armed and the power flow is from New South Wales (NSW) to VIC. IECS was implemented to minimise transmission network disruption and to significantly reduce the probability of cascading failure for the trip of multiple 330 kV and 220 kV transmission lines between Thomastown Terminal Station and Murray switching stations. The IECS is armed only if all the following conditions are met, to minimise risk of unnecessary load shedding and generation tripping due to potential mal-operation of the scheme:

- A fire is observed within 10 km from the common corridor of the monitored lines and the Country Fire Authority (CFA) has declared an Extreme or Code Red fire warning in the North Central or North East region in VIC, and
- The power flow across the interconnector is from NSW to VIC, and
- The monitored lines are not reclassified as a credible contingency.

The IECS has four operating modes – 1a, 1b, 1c, and 2. Only one mode out of 1a, 1b, and 1c can be enabled at a time, although mode 2 can be enabled independently from 1a, 1b, and 1c modes. The IECS monitors the status and the flow of certain lines based on the mode of its operation. Since the contingency considered for the study is the non-credible loss of Dederang to South Morang 330 kV lines mode 2, which monitors Dederang to Murray (DDTS-MSS) lines, is not applicable. The total power flow of the monitored lines is used to determine the amount of load and generation to be shed from the corresponding load and generation sequences. The study included the IECS operation under modes 1a, 1b, and 1c.

The non-credible loss of both Dederang to South Morang 330 kV lines was considered during high VIC import and export conditions and IECS operation was included for during VIC import conditions.

5.6.1 VIC import – historical cases

Study scenarios

Three cases were considered for the historical studies of the loss of both Dederang to South Morang 330 kV lines while VIC is importing. Historical cases were selected for study primarily based on maximum/high VIC import flows on Dederang to South Morang 330 kV lines (as high lines flows will present more onerous condition during the contingency). Coincident with high flows on Dederang to South Morang 330 kV lines, VIC inertia varied from 39614 to 43305 MW-s and VIC operational demand ranged from 8674 to 9122 MW. The range of power system variables considered for the studies are given in Table 46. Detailed parameters of each case are included in Appendix A6.7.1.

Table 46 Loss of Dederang to South Morang 330 kV lines: system operating points for the historical cases (VIC import)

VIC operational demand (MW)	VIC import (MW)	VIC inertia (MW s)	Total load available for load shedding (MW)	Total generation available for generation shedding (MW)	VIC renewables (MW)
8674-9122	639 - 1069	39614-43305	1134-1716	448-591	269-537

The maximum value ranges of key system variables observed during the simulations are summarised in Table 47. Detailed results for mode 1a, 1b, and 1c are included in Appendix A6.7.1.

Table 47 Loss of Dederang to South Morang 330 kV lines: results of the historical cases (VIC import).

IECS mode	Region	Frequency peak range (Hz)	Frequency nadir range (Hz)	RoCoF (Hz/s)	Total load shed (MW)	Total generation shed (MW)
1a	VIC	50.08-50.12	49.92 – 49.95	0.042 – 0.071	1090-1231	519-591
1b	VIC	50.08-50.13	50	0.042 – 0.069	1134-1292	519-591
1c	VIC	50.1-50.14	50	0.046 – 0.065	1134-1292	448-501

Key findings

The historical Dederang – South Morang line loss (VIC import) studies identified:

- The VIC frequency peak was maintained below 50.14 Hz for all the historical cases considered, and the maximum RoCoF was very low at only 0.071 Hz/s.
- A maximum of approximately 1,200 to 1,300 MW of load and 500 to 600 MW generation tripped for different modes of IECS operation.
- All the VIC import historical cases considered under the IECS 1a, 1b, and 1c modes were stable and the IECS action was sufficient to manage the contingency through generation and load trips.
- IECS is armed only during bushfire situations. AEMO recommends this be reviewed so the scheme is enabled at all times of VIC import to manage this non-credible contingency event.

5.6.2 VIC export – historical cases

Study scenarios

Ten cases were considered for the loss of both Dederang to South Morang 330 kV lines historical studies while VIC is exporting. Historical cases were selected for study primarily based on maximum/high flows on Dederang to South Morang 330 kV lines (as high lines flows will present more onerous condition during the contingency). Coincident with high VIC export flows on Dederang to South Morang 330 kV lines, VIC inertia varied from 14854 to 18509 MW-s and VIC operational demand ranged from 3668 to 4385 MW.The range of power system variables considered are given in Table 48. Detailed parameters of each case are included in Appendix A6.7.2.

Table 48 Loss of both Dederang to South Morang 330 kV lines: system operating points for the historical cases (VIC export)

VIC operational demand (MW)	VIC export (MW)	VIC inertia (MW-s)	Total load available for load shedding (MW)	Total generation available for generation shedding (MW)	VIC renewables (MW)
3668-4385	933-1429	14854-18509	NA	NA	510-1552

Key findings

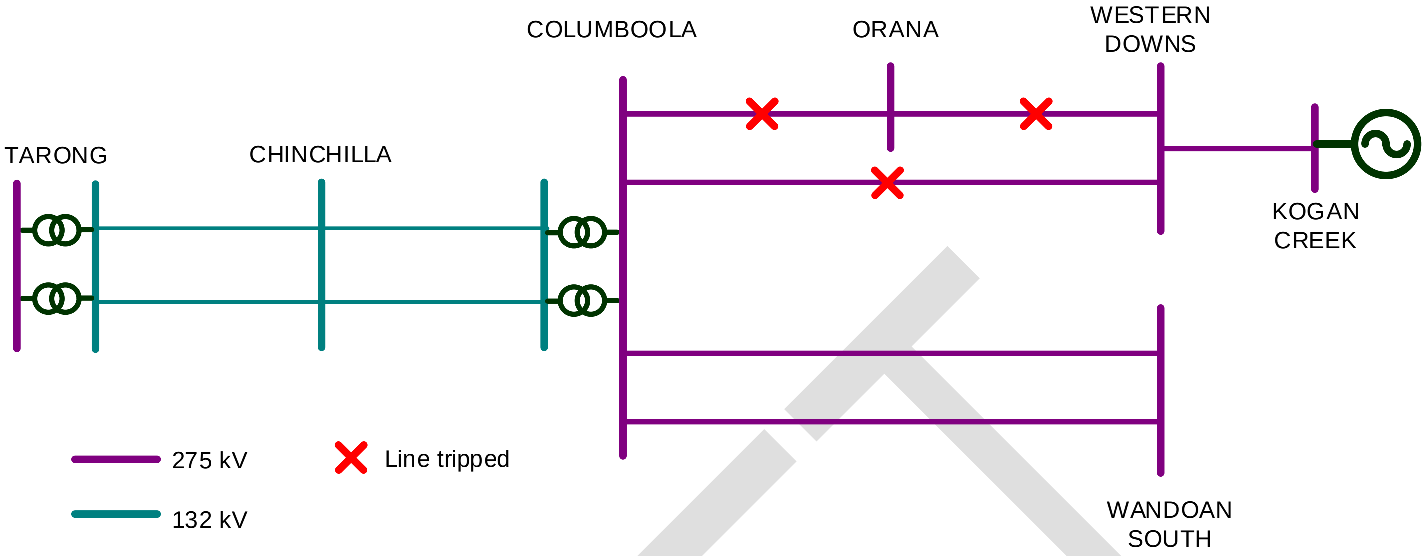
The historical Dederang – South Morang line loss (VIC export) studies identified:

- All cases failed to remain stable and large oscillations in frequency and voltage were observed. This indicates that this contingency could lead to a multitude of line losses and voltage collapse.

5.7 Contingency 8 – loss of Columboola – Western Downs 275 kV lines – historical cases

The non-credible trip of both 275kV lines between Western Downs – Orana and Western Downs – Columboola was considered. An approximate network representation of the Tarong – Columboola – Western Downs network is shown in Figure 18, including the lines considered in this study.

Figure 18 Tarong – Columboola – Western Downs approximate network



Following the loss of both 275 kV lines between Columboola – Western Downs, the loads in the Surat area network have remain connected to the Tarong 132 kV lines through Chinchilla substation. Due to the low capacity of these 132 kV lines, the Surat loads cannot be supplied resulting in overloading and voltage collapse of the 132 kV network. Overload protection installed on these lines is designed to trip in 500 ms, and this protection function was modelled in these studies.

Study scenarios

The loss of both 275 kV lines between Columboola-Western Downs lines will result in an approximate 600 MW of net load being lost in the Surat area. Historical cases were selected for study primarily based on maximum/high QLD export flows on QNI (as high QNI export flows will present more onerous conditions during the contingency). Coincident with high QNI flows and high Surat load, QLD operational demand ranged from 4631 MW to 7805 MW. Eight historical cases were considered to study the non-credible contingency, and the range of relevant key variables is given in Table 49.

Table 49 Range of key power system variables in study cases for non-credible loss of Western Downs – Columboola and Orana – Columboola lines

QLD operational demand (MW)	QNI export (MW)	Surat load (MW)	WDow-Col (MW)	Orana-Col (MW)	Col-WanS (MW)	Chin-Col (MW)
4631-7805	1164-1209	511-573	251-299	262-314	374-410	0-61

Key findings

The historical studies identified:

- All study cases failed during simulations because QNI lost stability. QNI losing stability indicates that the QNI line protection could operate and trip QNI, resulting in synchronous separation between QLD and the rest of the NEM.

- Tripping of the 132 kV lines between Columboola and Chinchilla 500 ms after the trip of 275 kV lines between Columboola – Western Downs as per current line protection may help to avoid overload and a possible voltage collapse in the Tarong – Chinchilla area network.

Following discussion with Powerlink, additional sensitivity studies were carried out to assess:

- The impact of inter-tripping feeders connected to Columboola 275 kV and 132 kV buses along with the non-credible loss of Western Downs – Orana and Western Downs – Columboola 275 kV lines.
- The impact of loss of load and generation in Surat area on QNI when QLD is exporting to NSW.
- The impact of tripping around 500 MW generation in QLD to manage QNI instability caused by load and generation loss in the Surat area.

Three cases were considered, and the range of power system variables is given in Table 50. More details of each case are included in Appendix A6.8.

Table 50 Range of key system variables in additional study cases for non-credible loss of Western Downs – Columboola and Orana – Columboola lines

QLD operational demand (MW)	QNI export (MW)	Surat area load (MW)	Generation at Columboola 132 kV (MW)	WDow-Col (MW)	Orana-Col (MW)	WDow-WanS (MW)
4669-5359	1185-1189	517-605	0	280-298	297-314	382-405

Key findings

The following key observations can be made from these additional studies:

- Following the contingency in all three cases, the increase in QNI flow led to instability (see results in Appendix A6.8.)
- A trip of around 500 MW generation in QLD to compensate the loss of Surat loads avoided QNI instability (see results in Appendix A6.8.)
- To manage the non-credible loss of Western Downs – Orana and Western Downs – Columboola 275 kV lines, Powerlink should consider an SPS to mitigate the risk of voltage collapse in the Surat and help preserve stability across QNI. Tripping 132 kV lines between Tarong and Columboola and tripping of generators in QLD could be considered as remedial measures among other options in SPS design.

6 Review of risk management measures

This chapter discusses the key risk management measures that require attention to improve power system resilience.

6.1 EFCS management

EFCS and emergency controls (typically SPSs) are the last line of defence in protection against power system collapse. Hence, maintaining the effectiveness of such protective mechanisms to manage the major non-credible risks is key to maintaining power system resilience. There are several EFCSs and SPSs that operate in the NEM to achieve this goal. OFGS and UFLS play key parts in the management of power system frequency during extreme frequency events.

6.1.1 OFGS review

OFGS schemes operate to trip generators for over-frequency events. At present, OFGS schemes are in operation in Tasmania, South Australia and Western Victoria. The following improvements are being pursued or planned to improve OFGS operation in different regions:

- South Australia OFGS: A review is almost complete, and modified settings or inclusion of new generators in the scheme are expected to commence in Q4 2022.
- Western Victoria OFGS: A review is almost complete, and modified settings or inclusion of new generators in the scheme are expected to commence in Q4 2022.
- Queensland OFGS: This PSFRR has identified a need for an OFGS in Queensland. AEMO and Powerlink intend to co-operate in its design and implementation. No dates have been set at this stage.

AEMO will continue to assess the need for an OFGS in New South Wales and the rest of Victoria.

6.1.2 UFLS review

UFLS is implemented in all regions, however, its efficacy and adequacy is reduced by increasing levels of DER. AEMO's analysis indicates that the amount of load under the control of under frequency relays in South Australia, Queensland, Victoria and New South Wales is now well below the levels anticipated in NER clause 4.3.1(k) when there are high levels of DPV operating, and that this is likely to deteriorate further in the coming years.

Each NSP is responsible for ensuring that sufficient load is under the control of under frequency relays or other facilities to minimise or reduce the risk of frequency falling below the EFETLs in response to simultaneous multiple contingency events (NER clause S5.1.10.1).

AEMO has advised NSPs in these regions that they should immediately identify and implement measures to restore emergency under-frequency response to be as close as possible to 60% of underlying load at all times[54]. Where this is not feasible, AEMO will collaborate with each impacted NSP to develop an approach that identifies a

[54] AEMO, Adapting and managing Under Frequency Load Shedding at times of low demand, at https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/operations/adapting-and-managing-under-frequency-load-shedding-at-times-of-low-demand.

level of emergency under frequency response that is achievable, while delivering a significant reduction in power system security risks.

AEMO recommends that NSPs explore approaches for the following:

- Adding more load into UFLS schemes.
- Addressing reverse power flows on UFLS circuits.
- Introducing active monitoring of UFLS load.
- Exploring long-term pathways for restoring emergency under frequency response.

AEMO is collaborating with NSPs in South Australia, Queensland and Victoria on the design and implementation of suitable remediation measures.

6.2 Situational awareness

Power system operation is becoming more challenging and complex. In response, AEMO is continuing to investigate improvements to its operational tools to improve control room situational awareness. Possible improvement areas include:

- High speed Electromagnetic Transient (EMT) simulation software.
- Improved SCADA displays.
- Improved visibility of DPV levels.
- Real-time assessment of UFLS availability and adequacy.
- Real-time frequency stability analysis (see Section 6.5).
- Visibility of more complex power system phenomena (such as ramping risks and power system oscillations).

6.3 Data and information

To better manage participant data, contact details, and cyber security risks, AEMO is investigating whether to implement a generator database. Ideally, this will have an interface allowing participants to update their information themselves. This will allow AEMO to securely access key up-to-date information when needed and improve its ability to identify which participants could be affected by issues related to specific manufacturers or equipment.

6.4 RAS guidelines

To better define the requirements for development of SPSs in the NEM, AEMO is collaborating with NSPs to develop a Remedial Action Schemes (RAS) Guideline. The objective of the guideline is to define good electricity industry practice for the design, modelling and review of schemes critical to the operation of the NEM. The guideline also provides a reference point for criteria that may be used to determine the acceptability of a proposed scheme. AEMO plans to publish the guideline for industry consultation in June 2022.

6.5 Management of ramping events in South Australia

Due to the penetration of DPV and transmission-connected IBR, South Australia is susceptible to large generation ramping events. These ramping events are becoming larger and more frequent as DPV and IBR penetration continues to increase in the region.

Through analysis, AEMO has identified ramping events in South Australia in 2021 where the combined DPV and IBR generator output reduced by over 1,750 MW over 2.5 hours. AEMO is analysing historical ramping events to understand ramping risk and how changes in synchronous generator dispatch requirements could impact AEMO's ability to manage future ramping events. After its review is complete, AEMO plans to explore options to forecast and manage future ramping events.

6.6 Recommended augmentation to Real Time Operations (RTO) Dynamic Security Assessment (DSA) tools

To better manage non-credible contingency events and their associated risks, AEMO considers that its DSA tools should be augmented with:

- Capabilities to predict the increased risk of major non-credible contingencies and islanding situations.
- Information on frequency control models, such as PFR governors and UFLS/OFGS availability.
- Inputs related to DPV generator availability and likely DPV contingency size for key faults.

7 Protected events

7.1 Existing protected event

Under the NER[55], AEMO is required to assess the following matters for existing protected events:

- Adequacy and costs of the arrangements for management of an event.
- Whether to recommend a request to revoke the declaration of an event as a protected event.
- The need to change the arrangements for management of an event.

There is presently only one protected event declared by the Reliability Panel:

> "*The loss of multiple transmission elements causing generation disconnection in the South Australia region during periods where destructive wind conditions are forecast by the Bureau of Meteorology*"[56].

This protected event is managed as follows:

- AEMO imposes a 250 MW South Australia import limit on the Heywood interconnector during forecast destructive wind conditions in South Australia.
- An EFCS called the System Integrity Protection Scheme (SIPS) is in place in South Australia to lower the risk of islanding due to trip of up to 500 MW of South Australian generation while South Australia is importing power.

The following sections assess this protected event for the existing network, and also considering two committed upgrades:

- Upgrade of SIPS to a more effective Wide Area Protection Scheme (WAPS).
- PEC Stage 1[57].

7.1.1 Current requirement

Since the 2020 PSFRR, AEMO has invoked the 250 MW import constraint to manage a protected event twice: on 11 January and 26 January 2022. In both instances, South Australia import over Heywood was greater than 250 MW prior to the protected event conditions arising. The constraint bound, reducing Heywood transfer to 250 MW, causing more expensive South Australian generation to be dispatched than would otherwise have been the case.

The costs[58] of constraining power flows during these two events are recorded in Table 60, showing a relatively low cost of the constraint.

[55] AEMC, National Electricity Rules, 5.20A.1(c)(3), at https://energy-rules.aemc.gov.au/ner/379.

[56] Reliability Panel AEMC, Final Report AEMO Request for a Protected Event Declaration, 20 June 2019, p22, at https://www.aemc.gov.au/sites/default/files/2019-06/Final%20determination%20-%20AEMO%20request%20for%20declaration%20of%20protected%20event.pdf.

[57] See https://www.projectenergyconnect.com.au/.

[58] Costs were calculated assuming Victorian brown coal was displaced by South Australian OCGT when the constraint bound, as was the methodology used in the original AEMO request for the protected event, at https://www.aemc.gov.au/sites/default/files/2019-04/AEMO%20Request%20for%20protected%20event%20declaration.pdf.

Table 60 Costs of historical binding constraints during protected events

Date	Binding period (mins)	HIC flow before binding (MW)	Cost of constraint
11 Jan 2022	40	495	$24,000
26 Jan 2022	120	574	$94,000

AEMO considers the arrangements for managing a protected event to be adequate. The risk of losing multiple transmission elements during destructive wind conditions, and the capability of the Heywood interconnector, remain the same as when the protected event was declared by the Reliability Panel in 2019. Therefore, the likelihood and consequences of the disconnection of multiple South Australian generators when importing above 250 MW are also largely unchanged[59]. The 250 MW limit remains a prudent risk mitigation measure.

AEMO does not recommend revoking the protected event or changing the 250 MW import limit used to manage the protected event at this stage. The need for the protected event post WAPS and PEC stage 1 commissioning are covered in the following sections, which also note the possibility for future management of the protected event under an expanded reclassification framework.

7.1.2 Post WAPS

SIPS will be upgraded to a new more effective scheme (WAPS), planned for implementation in early 2023. WAPS will further lower the risk of South Australia islanding (and subsequent system black) due to trip of multiple South Australian generators when South Australia is importing.

ElectraNet has advised that it expects the scheme to be more than 90% effective at preventing South Australia from islanding following a trip of up to 500 MW of South Australian generation at both 250 MW and 600 MW import[60]. To assess whether the 250 MW import limit should be revised, AEMO conducted a cost-benefit analysis assuming that constraining import to 250 MW increases WAPS' effectiveness by 1% compared to at 600 MW import (a likely conservative estimate).

The cost-benefit analysis was conducted assuming the same power system conditions as in the historical binding periods. The results in Table 61 show net benefits, even with a conservative 1% improvement assumption.

Table 61 Costs and benefits of South Australian 250 MW Heywood import constraint – assuming constraint improves WAPS effectiveness by 1%, and applied to historical protected events

Date	Binding period (mins)	HIC flow before binding (MW)	Cost of constraint	Benefit of constraint	Benefit/cost ratio
11 Jan 2022	40	495	$24,000	$121,000 - $363,000	5.0 – 15.2
26 Jan 2022	120	574	$94,000	$123,000 - $370,000	1.3 – 3.9

On the basis of this analysis AEMO does not recommend revoking the protected event or changing the 250 MW import limit used to manage the protected event, following commissioning of WAPS.

[59] There may be a slight increase in the probability of destructive wind conditions causing multiple South Australian generators to trip, because there are more generators connected now than in 2019.

[60] This is based on analysis that assumed a minimum of two synchronous generators online in South Australia. If this operating requirement is revised, additional analysis would be required to confirm whether this level of effectiveness could still be maintained.

7.1.3 Post Project Energy Connect Stage 1

The commissioning of PEC Stage 1 (shown in Figure 11) in the second half of 2023 will create a second AC flow path to South Australia. This will change the response of the South Australia network to a trip of 500 MW of generation and, therefore, should be considered in the assessment of the future management of a protected event.

ElectraNet has studied whether South Australia will still be at risk of islanding following the trip of 500 MW generation post PEC Stage 1. Preliminary studies indicate that losing 500 MW of generation during maximum import could lead to issues, including thermal overload of PEC Stage 1 plant. This could lead to a trip of PEC Stage 1, and a cascading trip of the Heywood interconnector, islanding South Australia and leading to a black system. ElectraNet is in the process of designing modifications to WAPS to be applied post PEC Stage 1 to mitigate these risks and minimise their economic impact. Details of proposed mitigating actions are presented below.

Given these changes to network conditions, the existing 250 MW constraint on Heywood that is applied during a protected event has been reviewed to determine if it will remain appropriate post-PEC Stage 1. The existing limit was calculated to provide 600 MW of headroom below the Heywood satisfactory limit of 850 MW[61]. The 600 MW of headroom was chosen to cover a 500 MW generation contingency and allow 100 MW of additional margin to cater for such factors as:

- Actual interconnector flows temporarily exceeding import limits due to variability of load and generation.
- Trip of DPV in addition to up to 500 MW generation trip.

AEMO calculates that constraining Heywood import to 430 MW and PEC Stage 1 import to 70 MW should be sufficient to prevent either interconnector exceeding satisfactory limits[62] following a trip of 500 MW of South Australian generation (this also includes 100 MW of margin split 70:30 between Heywood and PEC Stage 1).

The modified WAPS will aim to prevent South Australia islanding following a trip of 500 MW of generation, even at maximum South Australian import (approximately 600 MW on Heywood and 100 MW on PEC Stage 1). In light of the significant consequences of islanding, AEMO considers it prudent to constrain South Australia imports to 430 MW on Heywood and 70 MW on PEC Stage 1 during forecast destructive wind conditions, rather than rely on the modified WAPS alone.

AEMO conducted a cost-benefit assessment to determine the cost implications of this constraint. The assessment assumed that the modified WAPS will be 100% effective at preventing a black system following a 500 MW generation trip when South Australia imports are constrained to 430 MW on Heywood and 70 MW on PEC Stage 1, and that it will be 99% effective at maximum South Australia imports.

The cost-benefit analysis was conducted assuming the same power system conditions as in the historical binding periods, except that total South Australia import on the AC interconnectors was assumed to be 700 MW prior to a protected event, and constrained to 500 MW during the event. The results in Table 62 show net benefits.

[61] Reliability Panel AEMC, Final Report AEMO Request for Protected Event Declaration, 20 June 2019, at https://www.aemc.gov.au/sites/default/files/2019-06/Final%20determination%20-%20AEMO%20request%20for%20declaration%20of%20protected%20event.pdf.

[62] Heywood satisfactory limit is 850 MW, PEC Stage 1 satisfactory limit is 250 MW.

Table 62 Costs and benefits of South Australian 500 MW Heywood + PEC-1 import constraint – assuming constraint improves WAPS effectiveness by 1%, and applied to historical protected events

Date	Binding period (mins)	SA AC import binding (MW)	Cost of constraint	Benefit of constraint	Benefit/cost ratio
11 Jan 2022	40	700	$19,000	$172,000 - $517,000	8.9 – 26.5
26 Jan 2022	120	700	$58,000	$133,000 - $399,000	2.3 – 6.9

AEMO recommends that, as part of the delivery of PEC Stage 1:

- WAPS is modified to account for the change in network topology so as to remain as effective as possible in preventing South Australia islanding following trip of up to 500 MW of South Australian generation. ElectraNet is already progressing this.
- The existing 250 MW Heywood constraint applied during forecast destructive wind conditions is replaced by a 430 MW constraint on Heywood South Australian import and a 70 MW constraint on PEC Stage 1 South Australian import.

The modified WAPS will apply in South Australia, and will be commissioned in the second half of 2023 along with PEC Stage 1.

The AEMC made the "enhancing operational resilience in relation to indistinct events" rule in March 2022[63]. The rule requires AEMO to update the reclassification criteria by 9 March 2023 to reflect the broadened definition of 'contingency event' and other changes made by the rule, to better accommodate the reclassification and management of possible widespread contingency events in abnormal conditions. In the course of consultation on the reclassification criteria, AEMO will consider whether and to what extent the existing protected event could, in future, be best managed under the new reclassification framework rather than the protected event framework.

7.2 Potential protected event for QNI

The historical and 2027 future scenario studies indicate that QNI could lose stability following the loss of other interconnectors, such as HIC or PEC, and this could lead to multiple line and generation losses and the formation of islands. To manage QNI separation for interconnector contingencies elsewhere in the NEM, AEMO will conduct further investigation and studies to consider applying a protected event along with other measures, such as installation of an appropriate SPS to manage this issue.

7.3 Update on protected event for HIC

In the 2020 PSFRR, AEMO proposed that the non-credible separation of South Australia from the rest of the NEM be recommended for consideration as a protected event. Given the novel operating conditions emerging in South Australia, AEMO's analysis has required development and validation of new models and new analysis methodologies and remains in progress. AEMO is targeting a submission to the Reliability Panel in Q3 2022 on this issue.

The protected event is proposed to apply to a separation of South Australia from the rest of the NEM, including separation at HIC or at various points in the Victorian 500 kV network. Based on events during the past decade,

[63] AEMC, March 2022, at https://www.aemc.gov.au/rule-changes/enhancing-operational-resilience-relation-indistinct-events.

this type of event is anticipated to occur approximately once a year. The analysis only considers the period prior to commissioning of PEC.

Key findings from the studies to date are described further below, first examining the initial frequency arrest period, and then the subsequent frequency recovery period (up to 10 minutes after separation).

7.3.1 Frequency arrest

Assumptions and modelling approach for protected event assessment

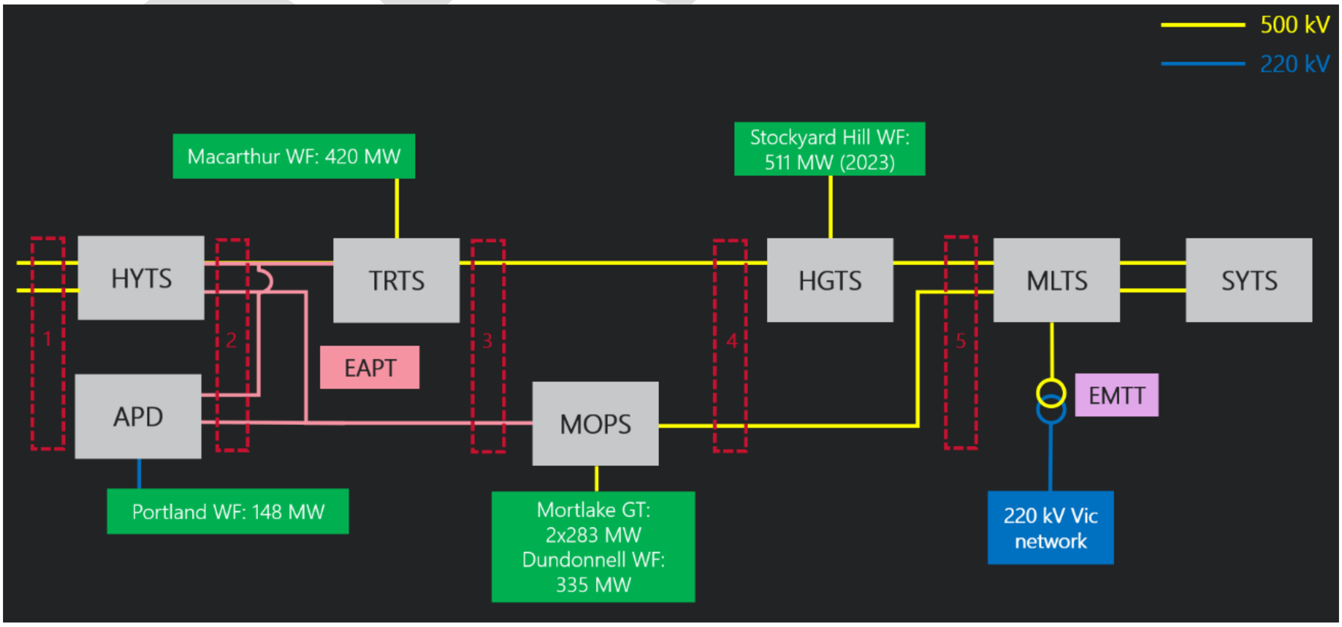
AEMO modelled the non-credible separation of South Australia from the rest of the NEM at the Heywood Interconnector, and also at various locations in the 500 kV South-West Victorian network, as shown in Figure 19.

Studies were conducted in a Matlab/Simulink multi-mass model with interconnector flow and generator dispatch outcomes informed by the ISP Plexos market model for every half-hour period during 2022-23 and 2023-24. The market modelling considered two scenarios:

- A minimum of two large synchronous generating units are required to remain online, in alignment with existing power system security requirements.
- No minimum synchronous generating units are required to remain online. In this scenario the model calculates dispatch scenarios with synchronous generating units operating when they are expected to recover their short-run marginal costs.

These two scenarios are intended to ensure any measures determined for a protected event are robust to the range of possible outcomes from parallel processes investigating minimum synchronous generation requirements in South Australia. The model applied is not designed to assess grid formation, system strength or voltage management aspects around the ability to form and operate a stable island with no synchronous generators online. These studies focus on frequency behaviour only, assuming that other aspects do not present a barrier to forming a stable island when operating with no synchronous generating units online.

Figure 19 Modelled network locations for the non-credible South Australia separation, labelled [1] to [5]



Model acceptance criteria are as follows:

- 'Fail' cases:
  - Under-frequency: Scenarios where minimum frequency falls below 47.6 Hz (allowing a buffer of 0.6 Hz over the requirement of 47 Hz in the FOS to allow for model uncertainty).
  - Over-frequency: Scenarios where maximum frequency exceeds 51.75Hz (allowing a buffer of 0.25 Hz under the requirement of 52Hz in the FOS to allow for model uncertainty).
- 'Risk' cases:
  - Under-frequency: Scenarios where minimum frequency falls below 48 Hz.
  - Over-frequency: Scenarios where maximum frequency exceeds 51.5Hz.

The criteria for risk cases have been selected to represent scenarios with an increasing risk of complications and adverse outcomes, with many power system elements operating far outside of their normal ranges.

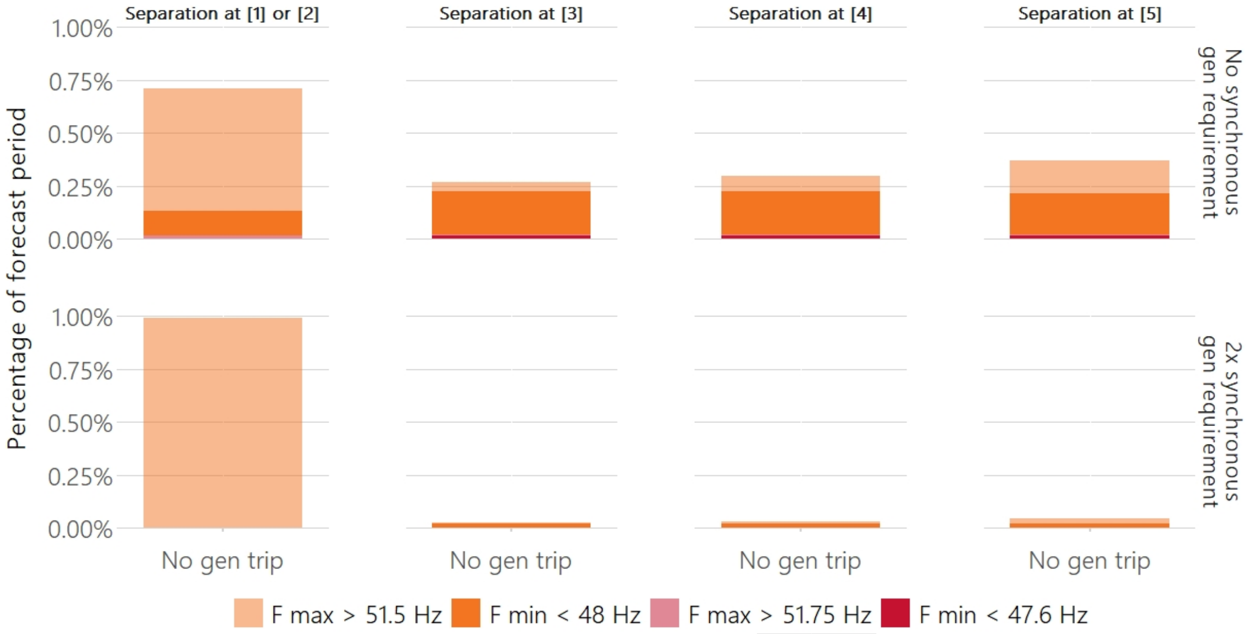
Preliminary findings

Preliminary findings indicate that risks are well managed by the existing constraint sets on the Heywood interconnector, which were updated in October 2020 to better meet TNSP transfer limits advice required under South Australian electricity regulations[64]. These constraints limit flows on HIC when the UFLS load is low, or RoCoF is projected to be too high for successful frequency arrest. Prior to implementation of the updated constraint sets, AEMO estimated that the interconnection was at risk for approximately 6% the time[65]. Since October 2020, the constraints have bound 4-5% of the time. AEMO's further analysis, shown in Figure 20, indicates that these constraints successfully maintain the incidence of 'risk' periods below 1% of the time for non-credible separation at any of the points indicated in Figure 19.

[64] *Electricity (General) Regulations 2012*, regulation 88A

[65] AEMO (October 2020) Heywood UFLS constraints, at https://aemo.com.au/-/media/files/initiatives/der/2020/heywood-ufls-constraints-fact-sheet.pdf?la=en&hash=066F80AE0EE3CF9701A0509818A239BB.

Figure 20 South Australian frequency risks in 2022-23 and 2023-24 following a double-circuit interconnector loss if no synchronous unit tripping occurs

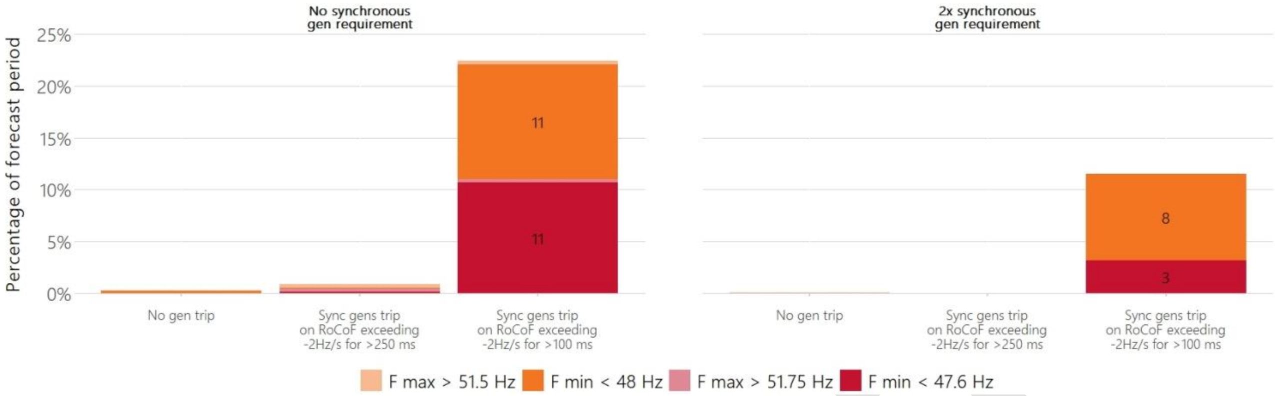


AEMO's analysis also indicates that very high RoCoF can be observed for a short duration following a separation at points [3] to [5], reducing following the operation of the Emergency APD Potline Tripping (EAPT) control scheme in South-West Victoria. In the 200-400 milliseconds (ms) prior to operation of the EAPT control scheme, however, synchronous generators in South Australia can be exposed to an extreme RoCoF, with levels exceeding ±4 Hz/s averaged over 300ms.

AEMO's previous analysis, and studies by international system operators, indicate that synchronous generators can be vulnerable to tripping when experiencing high RoCoF. AEMO investigated the power system consequences if certain units in South Australia tripped upon experiencing RoCoF exceeding various limits, as shown in Figure 21. Risks following a separation at [3] to [5] can increase to 10%-25% of the forecast period if certain South Australian synchronous generators trip on RoCoF exceeding 2 Hz/s for more than 100 ms (GE's advice to AEMO indicates this is plausible by various mechanisms, such as lean blowout, compressor surge, misbehaviour of power system stabilisers, or mal-operation of various protective schemes[66]). Risks are much lower if South Australian synchronous generators can ride through RoCoF of up to 2 Hz/s for up to 250 ms. The RoCoF ride-through capabilities of synchronous generators in South Australia are relatively unknown.

[66] GE Energy Consulting (9 April 2017) Report for AEMO, Advisory on Equipment Limits associated with High RoCoF, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017/20170904-GE-RoCoF-Advisory.

Figure 21 Frequency risks in South Australia in 2022-23 and 2023-24 if synchronous generators may trip on exposure to short-duration high RoCoF



Options under consideration

The various options under consideration for management of the identified risks are outlined in Table 63. Analysis is progressing to estimate technical feasibility and the costs and benefits of each approach for development of a submission to the Reliability Panel. All of these options (except UFLS restoration) can be implemented relatively rapidly following declaration of a protected event, noting that constraints and other operational interventions will need to be reviewed upon commissioning of PEC.

Table 63 Options under consideration for managing frequency arrest risks

	Options	Details	Status	
1	Restore UFLS	Restore emergency under-frequency response	✓	Work in progress with SAPN and ElectraNet. Full restoration might not be technically or economically feasible.
2	Heywood constraints	Constrain flows on Heywood interconnector when UFLS load is low	✓	Already implemented under SA electricity regulations[67], significantly reducing risks for non-credible Heywood trip. Seeking to formalise as a protected event.
3	EAPT mode switching	Switch EAPT control scheme to Mode 2 to enable faster operation under conditions where required to limit RoCoF exposure	×	Analysis suggests minimal benefit, with EAPT likely to operate regardless in Mode 2 timeframes due to voltage criteria.
4	Constrain flows at Moorabool	Constrain flows at Moorabool (VIC 500kV network) to limit RoCoF risk in periods where necessary	?	Constraint designed, estimating costs
5	Constrain-off specific synchronous units	Constrain-off specific generating units with suspected RoCoF trip risk during Moorabool separation risk periods	?	Under consideration
6	Generator testing for RoCoF ride-through	Test relevant generating units to confirm RoCoF ride-through capabilities	?	Seeking advice from equipment manufacturers on process and costs.

Summary

AEMO's analysis indicates that the existing constraints on the Heywood Interconnector reduce the risk of non-credible separation from 4-5% of the time to less than 1.2% however, if South Australia's synchronous generators trip when exposed to RoCoF exceeding -2 Hz/s for more than 100 ms, the risk could increase to up to 10-25% of the time during 2022-23 and 2023-24.

[67] *Electricity (General) Regulations 2012*, regulation 88A

AEMO proposes to make a submission to the Reliability Panel to effectively formalise the existing Heywood constraint sets within the protected event framework (upon confirmation of the cost-benefit analysis), and is also considering the costs and benefits for a suite of remaining options to manage RoCoF risks associated with separation events in the Victorian 500 kV network.

It is noted that there are other possible separation points (such as in the 275 kV South Australian network, and east of Moorabool Terminal Station in the Victorian network[68]), which have not been considered in this analysis, but could be considered in future work.

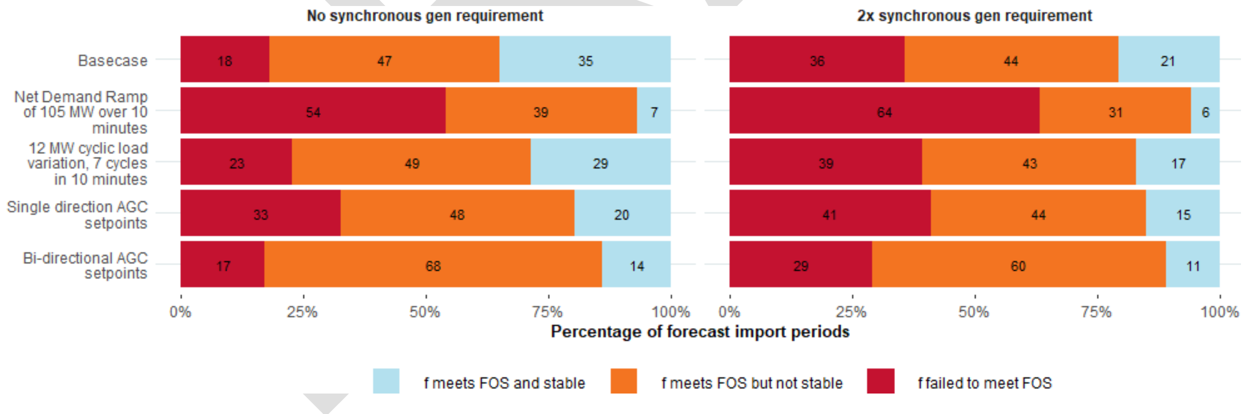
7.3.2 Frequency recovery

In addition to arresting frequency within the required thresholds, the FOS requires that, for a protected event, frequency recovers to within 49-51 Hz within 2 minutes, and 49.5-50.5 Hz within 10 minutes following a non-credible separation at Heywood[69]. If these recovery thresholds are not met, generators are not required to remain connected, and a cascading tripping event is plausible.

It can take up to 10 minutes following a separation event for the AEMO control room to diagnose and confirm the event and implement one or more of the required actions. Hence, automated processes must be in place to support the power system during this period. In the past, it has always been assumed that there would be sufficient generators online to assist with frequency recovery, but this might no longer be the case in South Australia, particularly during low demand periods. To address this, AEMO has developed and validated a new model for explicit analysis of frequency recovery dynamics over the 10 minutes following a separation event.

AEMO's analysis indicates that without intervention, frequency recovery in South Australia could fail to meet the FOS 20-40% of the time, as shown in Figure 22. Various sensitivities were also considered, including a co-incident net demand ramp, cycling demand variation, and the effects of AGC setpoints using a frequency reference outside of South Australia immediately following separation (until this is updated to island operation). These sensitivities all show similar or increased risks.

Figure 22 Frequency recovery outcomes with additional sensitivities (2022-23 and 2023-24)



These studies also highlighted that the dynamics of the power system in frequency recovery timeframes can differ considerably when the frequency arrest is achieved via proportional response from IBR, compared with traditional

[68] These include the non-credible loss of the 275 kV lines in SA between South East-Tailem Bend and Tailem Bend-Tungkillo/Cherry Gardens, as well as the loss of the 500 kV lines in Victoria between Moorabool and Sydenham which will result in Emergency Moorabool Transformer Tripping Scheme (EMTT) operation to trip the 500/220 kV transformers at Moorabool.

[69] Reliability Panel AEMC (January 2020) Frequency Operating Standard, at https://www.aemc.gov.au/sites/default/files/2020-01/Frequency%20operating%20standard%20-%20effective%201%20January%202020%20-%20TYPO%20corrected%2019DEC2019.PDF.

UFLS. Disconnection of load via UFLS sustains the response while frequency is stabilised and recovered. In contrast, fast-acting proportional resources, such as IBR, will withdraw their response proportionally as frequency recovers, which hinders recovery. This can be addressed by changes to the control schemes in IBR so that they can assist frequency recovery (termed “frequency recovery mode”).

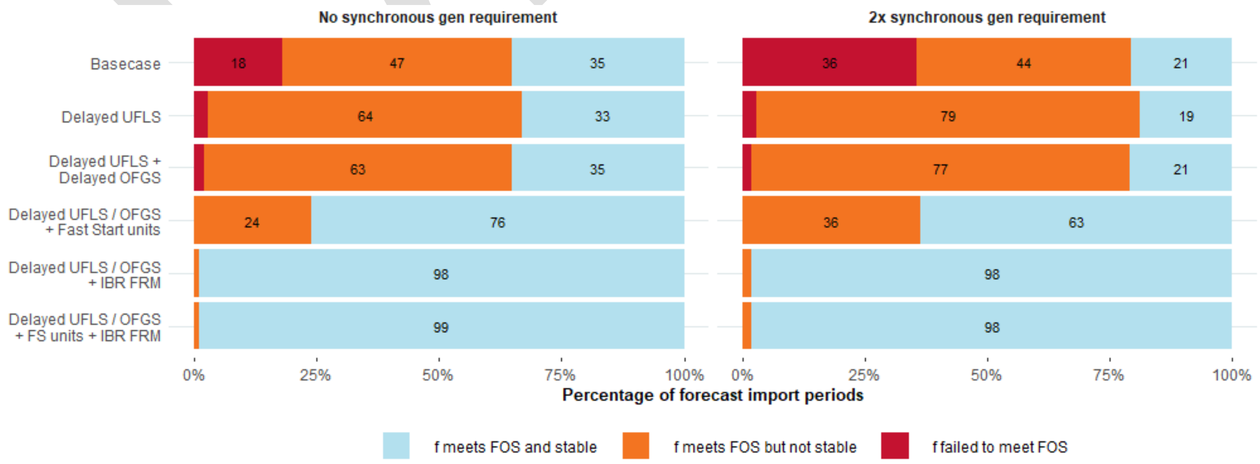
Table 64 summarises the various options under consideration to address the frequency recovery risks identified in this analysis, and Figure 23 shows their impacts on reducing risks.

Table 64 Options under consideration for managing frequency recovery risks

	Options	Details	Status	
1	Delayed UFLS	An additional delayed setting on capable UFLS relays that responds to a sustained under-frequency of <49.5 Hz with time delays in 15s increments from 90 to 300 s (120 MW total modelled).	✓	Finalising formal advice to SAPN. Does not require declaration of a protected event.
2	Delayed OFGS	Additional generation on the OFGS scheme that responds to a sustained over-frequency of >50.5 Hz with time delays in 15s increments from 90 to 135 s (160 MW total modelled)	✓	Proposed as part of OFGS uplift for SA and Western VIC. Does not require declaration of a protected event.
3	Enable 5min FCAS	Enable 5min raise Frequency Control Ancillary Services (FCAS) when importing into SA	×	Would require reservation of 100-200 MW of headroom in all importing periods, likely to be more expensive than other options.
4	Fast start units	Automated settings on fast-start generating units to synchronise and ramp up within 10 minutes in response to a sustained under-frequency. 100-200 MW addresses majority of risk periods and minimises risks of frequency over-shoot.	?	Developing specifications and aligning with SAPN’s procurement of Emergency Under-Frequency Response.
5	IBR implement Frequency Recovery Mode (FRM)	IBR with proportional frequency response typically respond very quickly to changes in frequency, which can hinder frequency recovery by withdrawing response as frequency is restored. This can be addressed by various changes to IBR settings, such as an automatic change in IBR set points following a sustained under frequency to assist with frequency recovery.	?	Developing specifications and aligning with SAPN’s procurement of Emergency Under-Frequency Response.

As shown in Figure 23, the implementation of delayed UFLS and OFGS significantly reduces the incidence of periods where the FOS is not met. The inclusion of fast start generating units and IBR Frequency Recovery Mode (FRM) almost eliminates the periods of failure and significantly reduces the more moderate risk cases.

Figure 23 Frequency recovery outcomes with mitigation options implemented (2022-23 and 2023-24)



AEMO is working with SAPN and other stakeholders to implement these actions, where feasible, and proceeding with cost-benefit assessments for the remaining actions to develop a recommendation to the Reliability Panel for a protected event, targeting Q3 2022.

8 Recommendations and conclusions

This chapter contains the key recommendations to manage non-credible risks considered in the 2022 PSFRR. Recommendations are based on the historical and 2027 future scenario studies carried out as part of the 2022 PSFRR. The specific study details that led to specific findings and recommendations outlined in this chapter are included in section 5 and Appendix A5.

8.1 Managing risks associated with non-credible South Australia separation

The 2027 future studies show that South Australian frequency might not recover within the time required by the FOS stabilisation band following a separation event. To stabilise and recover within that time, improvements to delayed UFLS/OFGS schemes and other possible approaches are being explored by AEMO. AEMO is collaborating with SAPN on updates to the delayed UFLS scheme, and this is also under consideration as part of a new protected event for South Australia separation.

8.2 Managing risks associated with non-credible Queensland separation

Historical studies show that when Queensland is exporting, Queensland frequency could rise above 52 Hz following the loss of QNI. To regulate frequency so as to meet the FOS, AEMO plans to collaborate with Powerlink to develop an OFGS for Queensland to manage over frequency during separation.

Future studies undertaken for 2027 scenarios show that following separation, Queensland frequency could collapse when Queensland is importing where the available UFLS is insufficient. AEMO has advised Powerlink and Energy Queensland to identify and implement measures to restore UFLS load, and to collaborate with AEMO on the design and implementation of remediation measures.

Future study scenarios also highlighted that QNI could lose stability following the non-credible loss of other interconnectors, such as HIC or PEC, and this could lead to multiple line and generation losses and the formation of islands. To manage QNI separation for interconnector contingencies elsewhere in the NEM, AEMO plans conduct further investigation and studies to consider applying a protected event or installation of an appropriate SPS to manage this issue. Initial studies on the determination of requirement of protected event may consider:

- Cost benefit analysis of the protected event due its market impacts.
- The impact of reclassification flow limits that are applied to HIC during damaging wind conditions on QNI stability.
- The impact of proposed PEC-HIC SPS to cover the non-credible loss of either PEC or HIC on QNI stability. Also, the effectiveness of PEC-HIC SPS to cover the non-credible separation of South Australia from MLTS.

8.3 Managing risks associated with the non-credible loss of DDTS-SMTS 330 kV lines

Based on historical studies, to avoid transmission line losses following the non-credible loss of DDTS-SMTS 330 kV lines, the following improvements are recommended:

- When VIC is importing: The IECS scheme is used to manage the impact of the non-credible loss of both DDTS-SMTS 330 kV lines. The scheme is currently enabled only during bushfires in the vicinity of these lines and when VIC is importing from NSW. Considering the impact of this non-credible contingency event on the power system, it is recommended that AEMO (as Victorian transmission planner) review the arming criteria.
- When VIC is exporting: It is recommended that AEMO (as Victorian transmission planner) implement a new SPS similar to the IECS to manage the non-credible loss of both DDTS-SMTS 330 kV lines. AEMO (as Victorian transmission planner) and Transgrid are advised to work together to design the generation and load trips as required for this new scheme.

8.4 Managing risks associated with non-credible loss of both Columboola – Western Downs 275 kV lines

The historical studies show that non-credible loss of Columboola – Western Downs 275 kV lines could cause multiple transmission line losses, equipment overloading and voltage collapse in the network around Surat in QLD and that this contingency could cause QNI to lose stability. To manage this contingency, it is recommended that Powerlink implement a new SPS under NER S5.1.8. Tripping 132 kV lines between Tarong and Columboola and tripping of generators in QLD could be considered as remedial measures among other options in SPS design.

8.5 Managing risks associated with non-credible loss of Calvale - Halys 275 kV lines

Future studies undertaken for 2027 scenarios show that following the QNI minor upgrade, when high QLD imports (above 600 MW) occur coincident with high CQ-SQ transfers, the WAMPAC scheme will not be able to ensure QNI and CQ-SQ cut-set line stabilities. To manage the non-credible loss of Calvale - Halys 275 kV lines, it is recommended that Powerlink modify WAMPAC to effectively manage this contingency.

8.6 Managing risks associated DPV growth and declining UFLS

To manage the power system security risks associated with the decline of the effective UFLS due to DPV growth, the following actions are recommended:

- To address the impact of DPV growth on UFLS, NSPs are advised to regularly audit the availability of effective UFLS considering the impact of DPV in their respective networks. This data should be regularly provided to AEMO so that it can be included in risk assessments, UFLS reviews and planning studies.
- To remediate the impacts of ‘reverse’ UFLS operation due to negative power flow on UFLS circuits:

- AEMO recommends that NSPs immediately seek to identify and implement measures to restore emergency under-frequency response as close as possible to the level of 60% of underlying load at all times. Where this is not feasible, AEMO will collaborate with NSPs to develop an approach that identifies a level of emergency under-frequency response that is achievable, while delivering a significant reduction in power system security risks.
- AEMO recommends that NSPs investigate measures to remediate the impacts of 'reverse' UFLS operation due to negative power flow on UFLS circuits and investigate arrangements to measure UFLS load availability in real-time to inform power system operation and planning studies.

8.7 Managing risks associated high RoCoF during major events

Future studies undertaken for 2027 scenarios indicate that with projected inertia levels, excessive OFGS and UFLS action can occur during high RoCoF events. AEMO will continue to monitor this in future general power system risk reviews and reviews of OFGS/UFLS settings, if required.